INTEGRATED POWER SECTOR MASTER PLAN FOR GHANA

MAIN REPORT

MARCH, 2023

GA-037-3212

info@energycom.gov.gh

www.energycom.gov.gh

+233 (0)302 813 756/7

P.M. B. Ministries, Accra Ghana

Integrated Power Sector Master Plan for Ghana

Volume #2

Main Report

March 2023

FOREWORD

The 2023 Ghana Integrated Power Sector Master Plan (IPSMP) is an output of months of work by the Energy Commission and various Ghana energy agencies, with financial support from the United States Agency for International Development (USAID) through the West Africa Energy Project (WAEP). In 2018, the first IPSMP was developed in close collaboration with Ghana energy sector agencies, led by the Energy Commission (EC), Ghana Grid Company (GRIDCo) and the Ministry of Energy (MoEn). This 2023 IPSMP is the second update of the 2018 IPSMP.

The vision of the IPSMP is to plan for a resilient grid power system that reliably meets Ghana's growing power demand in a manner that supports sustainable socio-economic development.

The IPSMP indicates that there is enough capacity (4,763 MW) to meet both demand at peak and the planned reserve margin of 18% for 2023 (4,328 MW) and 2024 (4,547 MW), therefore additional conventional thermal generation will not be needed until 2026. However, intermittent renewable energy sources will be added to help reduce generation cost in the medium term due to their comparatively low operational cost, and reduce fossil fuel dependency.

The Government of Ghana (GoG) is currently pursuing the Energy Sector Recovery Programme (ESRP) with the objective of curtailing the financial drain and averting such further occurrence going forward. The immediate objective of the ESRP is to provide a clear and comprehensive roadmap of strategic actions, reforms, and policies that would instil discipline into the energy sector to ensure financial viability and sustainability. For the medium-term, the ESRP provides a guiding framework to ensure good governance practices in the energy sector, by establishing a strong linkage between energy sector planning and timely procurement of energy infrastructure investments. These investments are expected to be supported by competitive, transparent, and fair procurement processes for acquiring new generation resources to ensure that electricity costs are as low as possible, which can translate into consumer tariffs that are as low as possible while being cost-reflective.

The objectives of the ESRP are very much in line with the recommendations of this version of the IPSMP. Regular updates of the IPSMP are very relevant to the fulfilment of the objectives of the ESRP and also the general planning of the power sector in a manner that supports sustainable socio-economic development of the country.

Ing. Oscar Amonoo-Neizer.
Executive Secretary, Energy Commission
March, 2023

ACKNOWLEDGEMENTS

The 2023 Integrated Power Sector Master Plan (IPSMP) was updated by the Energy Commission and the Power Planning Technical Committee (PPTC) with financial support received from USAID Ghana, through West Africa Energy Programme (WAEP).

The Energy Commission wishes to express its gratitude to ICF, the developer of IPM for extending the validity of the license at no cost. Also, we acknowledge support and feedback received from the USAID's local Energy Team (Mark Newton and Dorothy Yeboah Adjei) during the update of the IPSMP.

The Energy Commission and the PPTC team also acknowledge the important role played by officials from the Ministry of Energy in their sustained support for the 2023 update of the IPSMP.

The Energy Commission would like to thank the management and officials of the key stakeholder institutions—VRA, BPA, GRIDCo, ECG, NEDCo, EPC, PURC, GNPC, and GNGC—for their active participation in various activities associated with the updating of the 2023 IPSMP by dedicating resources and necessary data for the power sector modelling. They allowed their technical staff to work and provided the necessary data for the power sector modelling.

Stakeholder Institutions Participating in the IRRP Process

Volta River Authority (VRA)
Bui Power Authority (BPA)
Ghana Grid Company, Ltd. (GRIDCo.)
Electricity Company of Ghana (ECG)
Northern Electricity Distribution Company (NEDCo.)
Enclave Power Company (EPC)
Public Utilities Regulatory Commission (PURC)
Ghana National Petroleum Corporation (GNPC)
Ghana National Gas Company Ltd. (GNGC)

The PPTC Committee (see below) was established from these agencies, and these members contributed their time generously to ensure that the 2023 IPSMP was successfully updated in an inclusive manner. These stakeholder institutions are duly commended. All other stakeholders who provided data and specific suggestions that helped to shape the project and the update of the IPSMP are also duly acknowledged.

The 2023 Update of the IPSMP report was based on analysis of Ghana's power system as of the end of 2022 using ICF's power planning modelling tool, the Integrated Planning Model (IPM®).

Power Planning Technical Committee

Name	Institution
Mr. Salifu Addo	Energy Commission
Ing. Frank Otchere	Ghana Grid Company Limited
Ing. Mohammed T. Tampuri	Northern Electricity Company Limited
Ing. Hanson Monney	Ministry of Energy
Mr. Benjamin Buabeng-Acheampong	Ghana National Gas Company
Ing. Abdul Noor Wahab	Volta River Authority
Ing. Rasheed Baisie	Public Utilities Regulatory Commission
Mr. Ebenezer Baiden	Electricity Company of Ghana
Ing. Justice Barnor Kyere	Bui Power Authority
Mr. Joseph Kwaku Banuro	Energy Commission
Mr. Simpson Attieku	Energy Commission
Mr. Adolf Nii Ashong	Energy Commission
Mr. Francis Adjapong Yeboah	Energy Commission
Ing. Sheila Bortey-Kharis (Mrs.)	Ghana Grid Company Limited
Ing. Kassim Abubakar	Ghana Grid Company Limited
Monica Debrah (Mrs.)	Ghana Grid Company Limited
Ing. Frederick Okang	Ghana Grid Company Limited
Mr. Hamis Ussif	Ghana National Petroleum Corporation

Modelling Core Team

Name	Institution	Position/Function
Simpson Attieku	EC	Energy Planning
Joseph Kwaku Banuro	EC	Energy Planning
Felix Yeboah Koranteng	EC	Energy Planning
Ing. Frederick Okang	Ghana Grid Company Limited	Transmission modelling
Ing. Kassim Abubakar	Ghana Grid Company Limited	Demand/Transmission

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

List of Acronyms and Abbreviations

AAF	Automatic adjustment formula
AMR	Automatic meter reading
BAU	Business-as-usual
BGT	Bulk generation tariff
BNEF	Bloomberg New Energy Finance
BOT	Build-own-transfer
BPA	Bui Power Authority
BSP	Bulk supply substation
BST	Bulk supply tariff
CA	Connection agreement
CC	Combined cycle power plant
CT	Combustion turbine power plant
CEB	*Communauté Electrique du Benin* (Benin/Togo Generation and Transmission Power Utility)
CCR	Capital Charge Rate
CFL	Compact fluorescent lamp
CHT	Coal handling terminal
CIDA	Canadian International Development Agency
CIE	Cote d'Ivoire
CO_2	Carbon Dioxide
CSIR	Council for Scientific and Industrial Research
DAS	Distribution automation systems
DFI	Development finance institutions
DFO	Diesel fuel oil
DISCo	Power distribution company
DSC	Distribution service charge
DSM	Demand-side management
EC	Energy Commission
ECG	Electricity Company of Ghana
EE	Energy efficiency
EFOR	Effective forced outages rate
EIA	U.S. Energy Information Agency
EMOP	Electricity Market Oversight Panel
EPA	Ghana Environmental Protection Agency
EPC	Enclave Power Company
ESRP	Energy Sector Recovery Programme
ETU	Electricity transmission utility
EUT	End-user tariff
FIT	Feed-in-tariffs
FOB	Freight on board
FOM	Fixed operation and maintenance
FPSO	Floating production storage and off-loading
FSA	Fuel supply agreement
GAEC	Ghana Atomic Energy Commission
GCSA	Government consent and support agreement
GHS	Ghana Cedis (currency)

GDP	Gross domestic product
GEDAP	Ghana Energy Development and Access Project
GENCo	Power generation company
GH	Ghana
GHG	Greenhouse gas
GH-IPM	Ghana Integrated Planning Model
GIS	Geographic information system
GMP	Gas Master Plan
G-NDC	Ghana's Nationally Determined Contribution
GNGC	Ghana National Gas Company
GNPC	Ghana National Petroleum Corporation
GNPPO	Ghana Nuclear Power Programme Organisation
GoG	Government of Ghana
GRA	Ghana Revenue Authority
GRIDCo	Ghana Grid Company Ltd.
GSS	Ghana Statistical Service
GWh	Gigawatt hour
HFO	Heavy fuel oil
HRSG	Heat recovery steam generation
IAEA	International Atomic Energy Agency
IDC	Interest during construction
IEA	International Energy Agency
IMF	International Monetary Fund
IPM®	Integrated Planning Model
IPP	Independent power producers
IPSMP	Integrated Power Sector Master Plan
IRRP	Integrated Resource and Resilience Planning
ISO	Independent system operator
IWMI	International Water Management Institute
JICA	Japan International Cooperation Agency
kW	Kilowatt
kWh	Kilowatt-hour
LC	Letter of credit
LCO	Light crude oil
LDC	Load duration curve
LEAP	Long-range energy alternatives planning
LED	Light-emitting diode
LHV	Low heating value
LNG	Liquified natural gas
LPG	Liquefied petroleum gas
MAF	Million Acre Feet
M & E	Monitoring and evaluation
MCC	Millennium Challenge Corporation
MESTI	Ministry of Environment, Science, Technology, and Innovation
MiDA	Millennium Development Authority
MMBtu	Million British thermal units
MMcfd	Million Cubic Feet per Day
MoEn	Ministry of Energy

MoF	Ministry of Finance
MoP	Ministry of Power (erstwhile)
MoPet	Ministry of Petroleum (erstwhile)
MSW	Municipal solid waste
Mt	Million metric tonnes
MVA	Million Volt-Amperes
MW	Megawatt
MWh	Megawatt-hour
NDPC	National Development and Planning Commission
NEDCo	Northern Electricity Distribution Company
NEPIO	Nuclear Energy Programme Implementation Organisation
NES	National Electrification Scheme
NIP	National Infrastructure Plan
NITS	Nationally Interconnected Transmission System
NPC	Nuclear Power Centre
NOC	National Oil Company
NO_x	Nitrogen oxide
NPI	Nuclear Power Institute
NPV	Net present value
NRA	Nuclear Regulatory Agency
NREL	National Renewable Energy Lab
O&M	Operation and maintenance
PCC	Pulverized Coal Combustion
PCOA	Put-call-option agreement
PFG	Partnership for Growth
PNDC	Provisional National Defence Council
PPA	Power purchase agreement
PPTC	Power Planning Technical Committee
PSP	Private sector participation
PURC	Public Utilities Regulatory Commission
PV	Photovoltaic
RE	Renewable energy
REP	Rural Electrification Policy/Programme
REPO	Renewable Energy Purchase Obligations
RFP	Request for proposal
ROSATOM	State Atomic Energy Corporation of the Federation of Russia
ROW	Right-of-way
SCADA	Supervisory Control and Data Acquisition
SEG	Shenzhen Energy Group
SLT	Special Load Tariff
SMEC	Snowy Mountains Eng. Corp
SNEP	Strategic National Energy Plan
SNEP AEG	Accelerated Economic Growth scenario in the 2016 Draft SNEP
SO_2	Sulfur dioxide
STTA	Short-term technical assistants
TAPCo	Takoradi Thermal Power Plant
TBtu	Tera-British thermal units
TEN	Tweneboa, Enyenra, Ntomme

TICo	Takoradi International Company
TSO	Transmission System Operator
TSC	Transmission service charge
TTC	Total transfer capability
TWh	Tera Watt-hour
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
USAID	United States Agency for International Development
USc	United States dollar cents
USD	United States dollar
VALCo	Volta Aluminum Company
VAR	Volt-ampere reactive
VOM	Variable operation and maintenance
VRA	Volta River Authority
vRE	Variable renewable energy
WAGP	West African Gas Pipeline
WAGPCo	West African Gas Pipeline Company
WACC	Weighted Average Cost of Capital
WAPP	West Africa Power Pool
WEM	Wholesale Electricity Market
YoY	Year-on-Year

VOLUME 2: DETAILED ANALYSIS OF INTEGRATED POWER SECTOR MASTER PLAN

1. GHANA INTEGRATED POWER SECTOR MASTER PLAN

The Integrated Power Sector Master Plan (IPSMP) is a *strategic planning* document that provides a clear, comprehensive, and coherent view of the future development of power generation and transmission facilities in Ghana. This 2023 version of the IPSMP incorporates feedback received from various stakeholders in the power sector who reviewed the 2018 and 2019 versions, which were published by the Ghana Energy Commission on its website. This update also includes the latest electricity and peak demand projections, fuel supply projections (volumes and prices), financial assumptions for new construction, and transmission limits.

The IPSMP, which was developed in a coordinated manner with the participation of relevant energy sector agencies, was led by the Energy Commission. The IPSMP is rooted in sound technical analyses that consider various risks and uncertainties in a systematic manner. The analyses go beyond just updating supply-demand forecasts for electricity and developing a list of projects that are needed to meet future demand. The IPSMP also provides a rational basis for decision-making and implementation of least-cost projects, subject to constraints in the country. Thus, the IPSMP serves as an important policy document that sets out the vision, objectives, strategic plans, policies, and implementation plans for the ongoing development of the Ghana power sector.

To instil discipline and curtail the financial challenges in the energy sector, the GoG has put in place an Energy Sector Recovery Programme (ESRP), a strategic plan with the goal of ensuring financial viability and sustainability operational efficiency in the sector. The goal of the ESRP also includes the procurement of generation and transmission resources in a fair, competitive and transparent manner to ensure that electricity end-user tariffs are as low as possible. The IPSMP fulfils one of the requirements of the ESRP—to provide a strong linkage between energy sector planning and infrastructure investments.

Consequently, the development of the IPSMP and its regular updates are very relevant to the fulfilment of the objectives of the ESRP and the general development of the power sector in a manner that supports the financial sustainability of the power sector.

Any Master Plan, including this IPSMP, is always developed in a state of incomplete and evolving information. Therefore, regular updates of the IPSMP are necessary to address the changes and new challenges in the power sector over time. The IPSMP outlines a staged process of information and institutional development and identifies potential “decision-trees” and critical factors that are dependent on additional information that should be gathered and analysed over time.

Broad stakeholder workshops including the Technical Committee meetings were held to seek feedback on the 2019 version of the IPSMP as well as update the assumptions and inputs required for the 2023 version of IPSMP.

Similar to the 2018 and 2019 IPSMP reports, the 2023 IPSMP update is based on the output of technical analyses that were conducted using a dynamic, least-cost linear optimisation planning tool called the Integrated Planning Model (IPM®)[1]. The IPM relies on sectoral data on electricity demand and the power supply system (i.e., the generation and transmission systems) to undertake least-cost scenario analysis of electricity supply strategies and policies and to simulate both production cost and capacity expansion of Ghana's power system in the mid- to long-term planning horizons. The IPM takes into consideration various operational and contractual constraints to evaluate plant generation levels, and determine new power plant construction, fuel consumption, and inter-regional transmission flows.

1.1. IPSMP Vision and Objectives

The vision of IPSMP is to develop "*a resilient power system to reliably meet Ghana's growing power demand in a cost-effective manner that supports the country's sustainable development*".

The specific objectives that define the course to realise this vision are:

1. Achieve cost-competitiveness in power generation and delivery;
2. Reliably meet local demand and exports in a timely manner;
3. Increase resilience of the power system;
4. Ensure positive economic impacts through job creation and GDP growth;
5. Meet Ghana's local environmental and climate change commitments;
6. Promote and implement sustained energy efficiency and demand-side management (DSM) programmes; and
7. Support secondary objectives beyond current universal access goals (e.g., productive uses of electricity, household-level connection, mini-grids).

The IPSMP vision and objectives are aligned with the Government of Ghana's (GoG) policies in the power sector, and they were developed in a collaborative process led by the Energy Commission.

1.2. Approach for Developing 2023 IPSMP - UPDATE

The 2023 IPSMP, an update of the 2019 IPSMP, was undertaken by the PPTC led by the Energy Commission with financial support from USAID under the WAEP. It was very consultative, with active participation of stakeholders from the energy sector. The report relied on inputs, assumptions, and feedback from reviews of the 2019 IPSMP report, and comprehensive discussions of the modelling framework and model results to arrive at a consensus for the 2023 IPSMP.

The input data for the Ghana-IPM modelling platform that was used to facilitate the requisite analysis, were collated from the various stakeholder institutions in the power sector, with support from the PPTC and the IPM Modelling Team. Where necessary, data were also obtained from reputable third-party sources. All of the data were carefully vetted and discussed with the source agencies to confirm their validity and integrity.

1 The IPM modelling platform is a product of ICF and is used in support of its public and private sector clients. IPM® is a registered trademark of ICF Resources, L.L.C.

The resilience of the power system was evaluated by carrying out sensitivity (scenario) analysis on a set of adopted strategies in order to understand how uncertainties and risks, which may be encountered over the planning period, can impact the least-cost outcomes of the IPM model. A "Least-Regrets" solution was then determined by evaluating how different policies and strategies for the future development of the Ghana power sector will respond under the varying sensitivities. The Least-Regrets Strategy has the overall best system characteristics in terms of cost, resilience, reliability, and environmental concerns, even under a broad range of potential techno-economic futures.

Figure 1 shows the framework for the IRRP and the analyses leading to the 2023 IPSMP update. The planning process adopted by the PPTC in updating the 2019 IPSMP report is illustrated in Figure 2.

1.2.1. Feedback and Update Process for IPSMP

The draft 2023 IPSMP was presented to the Ministry of Energy, Volta River Authority, Ghana Grid Company, Electricity Company of Ghana, Northern Electricity Distribution Company, Ghana National Petroleum Corporation, and Ghana Gas Company, among others, for their review and comments. The feedback from these stakeholders was incorporated into the Final 2023 IPSMP.

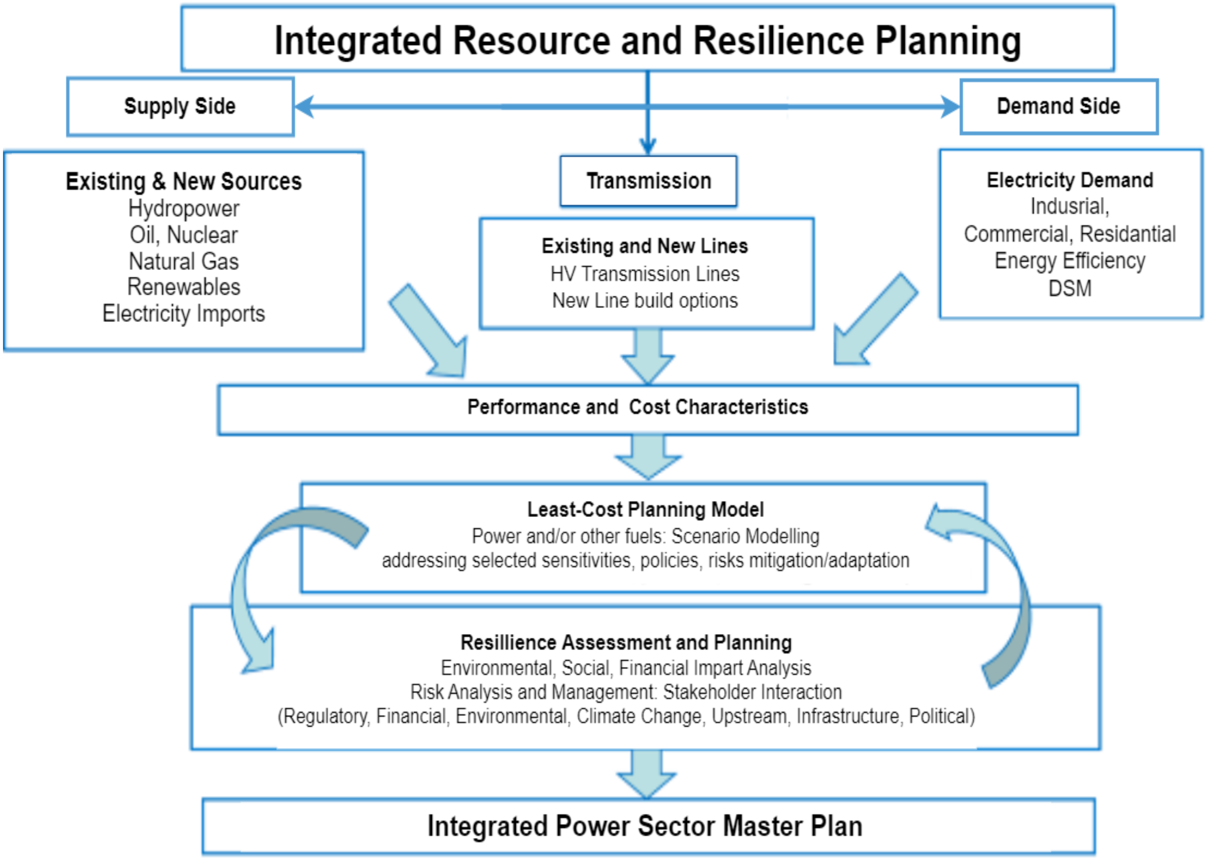


Figure 1: Framework for IRRP

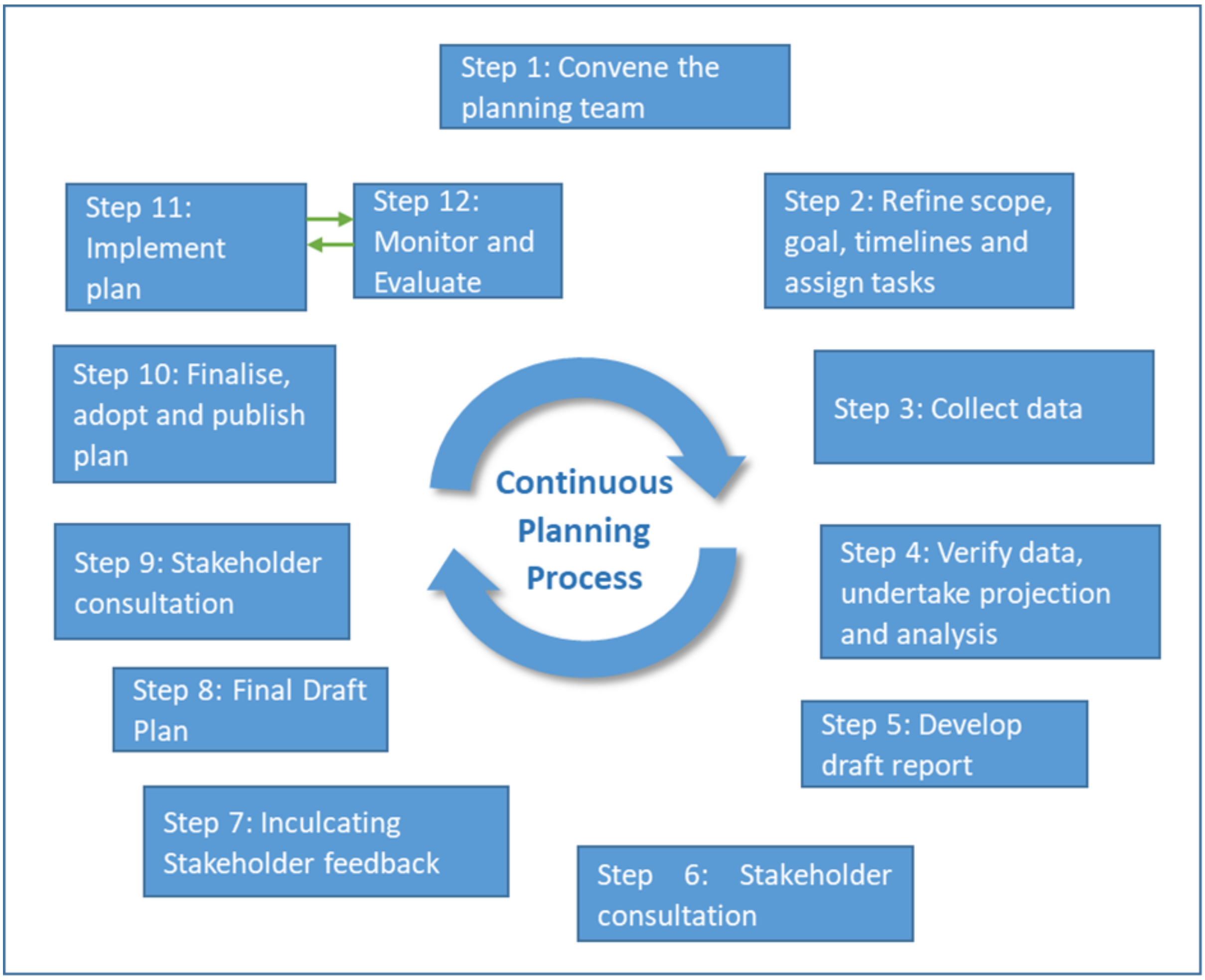


Figure 2: Adopted Planning Process

1.3. Organisation of the 2023 IPSMP Report

The information presented in this 2023 IPSMP report has been written concisely and structured in a logical sequence to facilitate effective reading and understating as well as referencing.

Volume 1 is a stand-alone Executive Summary designed for decision-makers.

Volume 2 provides a detailed description of the modelling framework used for the plan, the key variables used in the analysis as well as the renewable energy landscape, and financial issues. Following this, discussion on modelling inputs, the results of the modelling are described with a particular focus on the least-cost strategies and Least-Regrets scenarios. This volume also includes a series of recommendations associated with various parts of the electricity value chain.

Volume 3 contains the relevant data used and analysis conducted for the development of the 2023 IPSMP in a stand-alone set of appendices.

2. BACKGROUND AND KEY ISSUES

2.1. ASSESSMENT OF THE GHANA POWER SYSTEM

The goal of Ghana's power sector is to efficiently supply power that adequately meets the power needs of the country as well as be a major net power exporter in the West African sub-region. In an effort to achieve this goal, the country has developed strategic plans, including the IPSMP, to ensure the steady addition of adequate generation capacity and the upgrade and modernization of the transmission and distribution infrastructure in a timely and cost-effective manner. It is in view of this goal that the 2023 IPSMP report updates the 2019 IPSMP version, which provided an assessment of the performance of the country's power sector (up to 2018). The 2023 IPSMP report presents a review of Ghana's power system and highlights requirements that will ensure a robust or resilient power system performance in the medium to long term.

Electricity Consumption

Total electricity consumption increased from 14,291GWh in 2019 to 15,434GWh in 2020 and 16,898GWh in 2021 representing 8.2% and 9.5% YoY growth respectively. Despite the devastating effects of COVID-19 on global economies, the COVID-19 pandemic did not have any significant effect on electricity supply and demand in 2020 and 2021[2]. In 2022, the total electricity consumption of 17,516 GWh was also 3.7%% more than that of the previous year (2021).

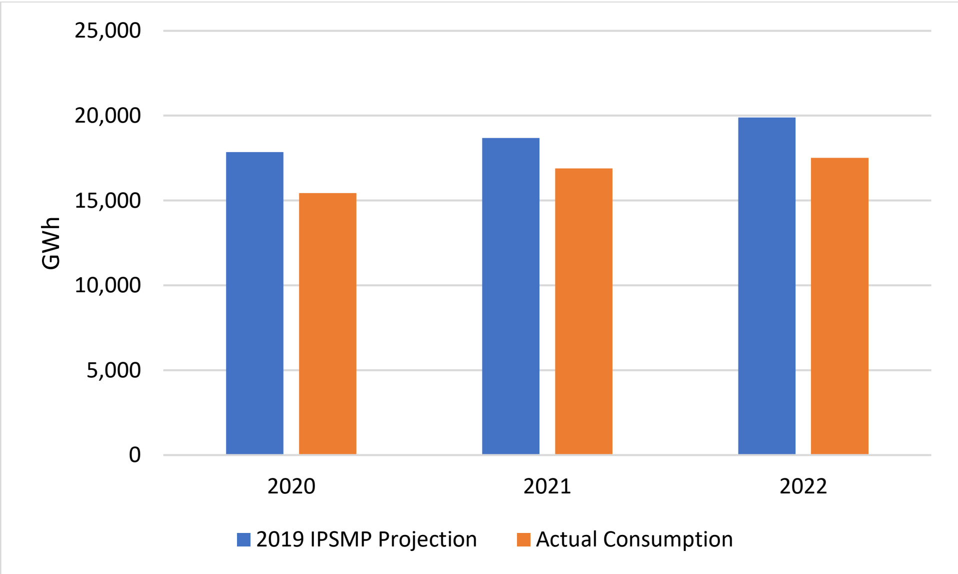


Figure 3: Electricity Consumption projection vs Actual

The 2019 IPSMP report projected a total electricity RefCase demand of 17,855 GWh in 2020, which was 15.7% higher than the actual, and 18,685 GWh in 2021, which was also 10.6% higher than the actual. The electricity consumption is lower than the projected mainly because of

[2] 2021 Electricity Supply Plan, Page iii
www.energycom.gov.gh/files/2021%20Electricity%20Supply%20%20Plan_Final.pdf

economic downturn during this period. The 2019 IPSMP used 6% GDP growth rate but the average GDP growth rate within this period (2020-2022) was 2.9%[3].

The annual electricity consumption in Ghana (with and without VALCo), indicates a strong influence of VALCo's operations on the total electricity consumption of Ghana. Hence, a key issue that needs to be assessed critically is how VALCo will operate in the future and how its influence or impact on future demand for electricity will be.

In 2019, the maximum coincident peak demand, which occurred on December 3, was 2,804 MW. This increased by 11% to 3,090 MW in 2020 (recorded on December 4). The maximum coincident peak demand increased by 10% to 3,246 MW in 2021 and this occurred on December 8. The actual Ghana peak load realised for the year 2022 was 3,469.0 MW and was recorded in March 2022. The peak load recorded for 2022 also represents a 6.9% (223.0 MW) growth over the 2021 peak load of 3,246.0 MW.

The 2019 IPSMP report, projected a maximum coincident peak demand of 3,048 MW in 2021, which was 6% lower than the actual. In 2022, the projected peak demand of 3,230 MW was also 7% lower than actual.

In 2019, the residential sector was the dominant sector (43%) regarding electricity consumption, while the industrial sector was the second most dominant sector (36%). The COVID-19 pandemic did not have any significant impact on electricity demand in Ghana. There was however an increase in residential energy consumption possibly due to the social adjustments driven by containment measures adopted where most Ghanaians stayed at home. However, by 2022, the industrial sector displaced the residential sector as the most dominant electricity-consuming sector (42%). The total electricity consumption in Ghana increased by 22.8%, from 14,261 GWh in 2019 to 17,547 GWh in 2022. See Table 6.

Electricity Imports and Exports

Table 1: Electricity Imports and Exports from 2019 to 2022

	2019	2020	2021	2022
Imports	127	58	44	37
Exports	1,430	1,855	1,734	2215
Net Exports	1,303	1,797	1,690	2178

Source: Energy Commission's National Energy Statistics, 2023

As shown in **Table 1** above, electricity import in 2019 was 127 GWh. This decreased significantly to 58 GWh in 2020 and 37 GWh in 2022. This is in line with government policy to decrease electricity imports but rather increase electricity exports to become a major net electricity exporter in the sub-region. In 2022, the country had a net export of 2,178 GWh of electricity.

[3] Ghana Statistical Service; https://statsghana.gov.gh/nationalaccount_macros.php?Stats=MjcxODMxNjI5OC43Nzk1/webstats/pr5np66697

Electricity Supply

The total installed and dependable electricity generation capacity from the end of 2019 to the end of 2022 is presented in **Table 2** below.

Table 2: Total Installed and Dependable Capacity (MW) by Technology

	2019		2020		2022	
	Installed	Dependable	Installed	Dependable	Installed	Dependable
Hydro	1,584	1,365	1,584	1,400	1,584	1,400
Thermal	3,682	3,296	3,694	3,435	3,753	3,482
RE sources	43	34	59	47	144.05	94.65
Total	**5,309**	**4,695**	**5,337**	**4,882**	**5,481**	**4,975**

Source: Energy Commission's National Energy Statistics, 2023

The total dependable electricity generation capacity at the end of 2019 was 4,695 MW compared to a peak demand of 2,804 MW. In 2019, hydropower accounted for 30% of the total installed generation capacity, whilst thermal power accounted for 69%. In addition, RE sources accounted for about 1% of the total installed capacity. The total dependable capacity in 2019 increased by about 4% to 4,882 MW in 2020 compared to a peak demand of 3,090 MW. In 2020, hydropower accounted for 29.7% of the total installed capacity whilst thermal increased to 69.2% and RE source was 1.1%. The total dependable generation capacity at the end of 2022 was 4,975 MW compared to a peak demand of 3,246 MW. The total installed capacity in 2021 was about 3% increase over that of the previous year. In 2022, the share of hydropower decreased to 28.9% of the total installed generation capacity, and thermal further increased to 68.5% with RE sources increasing to 2.6%.
The total amount of electricity (GWh) supplied from domestic plants from 2019 to 2021 according disaggregated to technology, is presented in **Table 3** below.

Table 3: Total Electricity supplied from domestic plant

	2019	2020	2021	2022
Hydro	7,252	7,293	7,521	8,213
Thermal	10,885	12,820	14,408	14,810
RE Sources	52	57	122	140
Imports	127	58	44	37
Total	**18,316**	**20,228**	**22,095**	**23,200**

Source: Energy Commission's National Energy Statistics, 2023

The total amount of electricity supplied from domestic power plants according to technology and imports was 18,316 GWh in 2019. In 2019, electricity supplied from hydropower accounted for 39.6% of the total electricity supplied whilst thermal power accounted for 59.4%. Electricity supplied from imports was responsible for 0.7% and that from RE sources was 0.3% of the total supplied. The total amount of electricity supplied in 2019 increased by 3.1% to 20,228 GWh in 2020. In 2020 and 2021, the share of electricity supplied from hydropower sources decreased to 36% and further decreased to 34% of the total electricity supplied respectively, whilst that from thermal power increased to 63.4% and 65%. The share of electricity supplied from RE sources in 2020 remained at 0.3% and that for imports decreased to 0.3% of the total electricity supplied. The total annual electricity supplied in 2020 increased by about 9.0% to 22,095 GWh in 2021 and by 5% from 2021 to 2022. The share of annual electricity supply from hydropower sources increased in 2022 to 35% of the total electricity supply. The share of thermal decreased to 64% whilst that from RE sources remained around 0.6% and imports decreased to 0.16% of the total electricity supplied in 2022.

2.2. Fuel Supply Mix for Electricity Generation

- **Hydrology and Hydropower generation**

The amount of hydropower generation depends entirely on the amount of water in the reservoirs (e.g., the Volta Lake for Akosombo Power Plant), which receive inflows from their catchment areas. The recorded net annual inflows into the Volta Lake for 2019 and 2020 was 33.43 Million Acre Feet (MAF) and 31.86 MAF respectively.

In 2021 the recorded total inflow was 31.01 MAF, which was 3% lower than the inflow in 2020. The inflows from 2019 to 2022 were all above the long-term average annual inflow of 30 MAF for the Volta Lake.

Total hydropower generation (from Akosombo, Kpong and Bui) Hydro Power Plants (HPP) was 7,252 GWh and 7,293 GWh in 2019 and 2020 respectively. In 2021, hydropower generation from the HPP was 7,521 GWh, which was 3% higher than the generation in 2020.

- **Natural Gas Supply**

Natural Gas supplies for electricity generation in the country are met by Ghana's domestic gas fields (Jubilee, TEN and Sankofa) and supplemented by imports from Nigeria through the West African Gas Pipeline (WAGP).

The total amount of lean natural gas supplied from the Atuabo Gas Processing Plant (which processes Jubilee and TEN gas) and Sankofa for both power and non-power purposes in 2019 was 55.3 TBtu. The domestic lean natural gas supplied increased by 72% to 95.2 TBtu in 2020 with the PURC approved weighted average cost of gas (WACOG) of US$ 6.08/MMBtu. In 2021, the total gas supplies increased by 13.2% to 107.8 TBtu, with the WACOG remaining at US$ 6.08/MMBtu. In 2022, the total gas consumption was 127.8 TBtu whiles th WACOG reduced to US$ 5.91/MMBtu.

In 2019, 23.8 TBtu of natural gas was imported for electricity generation at a total cost of US$ 169.57 million. The average price of imported natural gas in 2019 was about US$ 7.12/MMBtu. Natural gas imports for electricity generation increased by 3% to 24.4 TBtu in 2020 at a total cost of US$ 175.84 million with an average price of about US$ 7.19/MMBtu. In 2021, natural gas imports for electricity generation reduced to about 18.71 TBtu at a total cost of US$ 140.29 million and at an average price of US$ 7.50/MMBtu.

The quantity and price of lean natural gas supplied by Ghana National Gas Company (GNGC) from the Atuabo Gas Processing Plant (GPP) for both power and non-power purposes are shown in Figure 4.

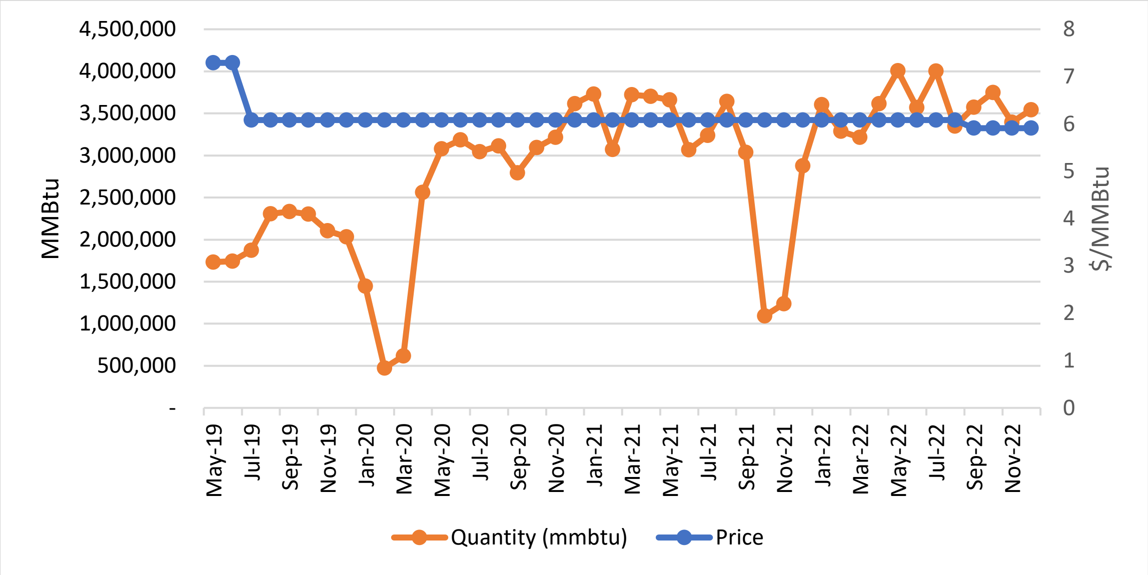


Figure 4: Monthly Lean Gas Production and Prices

Source of Data: GNGC, PURC

- **LCO, DFO and HFO Supply**

The dependence on liquid fuels for power generation in Ghana has greatly diminished following the discovery and use of natural gas for power generation. Few thermal plants run on either Light Crude Oil (LCO) or Diesel Fuel Oil (DFO) as secondary fuel. These plants provide strategic options for generation in instances where gas supply interruptions occur. In 2020, a total of 1,081,444 bbls of liquid fuels were used mainly by Amandi, Cenpower, Tico, KTTP and AKSA as a main or startup fuel for electricity generation. By 2022, this figure had reduced to 698,982 bbls. In energy terms, the consumption of liquid fuels represents about 5%, 3%, and 0.09% of natural gas consumed in 2020, 2021, and 2022 respectively.

Electricity Transmission

The electricity supplied, from generating plants and imports, is evacuated through a transmission network, which had a total length of approximately 6303.9 km terminating at 68 bulk supply substations (BSPs) as of mid-2021. The transmission voltage levels span 69 kV (212.8 km), 161 kV (5065.9 km), 225 kV (92.2 km) and 330 kV (933 km). The length of the transmission network is expected to further increase by the end of 2022 as new projects come online. The total transformer capacity stood at about 8064 MVA at the end of 2021.

The country's national grid is interconnected with the following three neighbouring countries: Togo/Bénin (CEB) at 161 and 330 kV, Cote d'Ivoire (CIE) at 225 kV, and Burkina Faso (SONABEL) at 225 kV. There are a number of other cross-border connections at 33kV for some mines and border communities of Cote d'Ivoire, Togo and Burkina Faso.

The total amount of electricity transmitted and the losses on the transmission system are presented in **Table 4**.

Table 4: Total Energy and Transmission losses

	2019	2020	2021	2022
Transmitted (GWh)	17,887	19,717	21,466	22,478
Losses on transmission (GWh)	843	888	1,076	922
% Losses on transmission	4.7	4.5	5.0	4.1

Source: National Energy Statistics, 2022

The total amount of electricity transmitted in 2019 increased by 10% to 19,717 GWh in 2020. The electricity transmitted in 2022 was 5% higher than that which was transmitted in 2021. The average transmission loss per annum from 2019 to 2022 was about 4.6%. A number of projects were initiated in 2018 and are expected to be completed by 2023 to resolve transmission constraints, transformer overloads and reduce losses. Some of these projects include the completed Pokuase Bulk Supply Point and the under construction Afienya Bulk Supply Point.

Electricity Distribution

The distribution companies in the country are ECG, NEDCo, and Enclave Power Company (EPC). In 2019, the total amount of electricity distributed in the country was 9,924 GWh. This increased by 8% to 10,718 GWh in 2020. In 2022, the total amount of electricity distributed was 11,808 GWh, which was 4% more than the previous year.

Table 5: Electricity Distribution in Ghana

	2019	2020	2021	2022
ECG	8,685	9,333	9884	10,274
NEDCo	1,010	1,148	1,281	1,307
EPC	229	237	230	227
Total	9,924	10,718	11,395	11,808

Source: National Energy Statistics, 2023

It can be observed in **Table 5** that ECG account for 87.1% of the total electricity distributed in the country from 2019 to 2022. This is followed by NEDCo, which accounted for about 10.8% of the total electricity distributed, with EPC accounting for about 2.1%.

The total electricity consumption according to the various sectors of the economy from 2019 to 2021 is presented in **Table 6**

Table 6: Electricity consumption by Sectors

	2019		2020		2021		2022	
	GWh	%	GWh	%	GWh	%	GWh	%
Residential	6,078	43	6,829	44	6,959	41	7,111	41
Industry	5,081	36	6,226	40	7,130	42	7,428	42
Service	3,081	22	2,355	15	2,773	16	2,965	17
Agriculture	11	0	17	0	25	0	33	0
Transport	10	0	7	0	10	0	11	0
Total	**14,261**	**100**	**15,434**	**100**	**16,898**	**100**	**17,547**	**100**

Source: National Energy Statistics, 2023

The total consumption in 2019 was 14,261 GWh, which increased by 8.2% to 15,434 GWh in 2020 and further increased to 16,898 GWh in 2021. In 2022, the total electricity consumption increased by 3.7% to 17,547 GWh.
The residential sector was the largest consumer of electricity in Ghana from 2019 to 2022, accounting for 43% to 41% of total electricity consumption. The industrial sector was the second-largest consumer, accounting for 36% to 42% of total consumption over the same period. The service sector's consumption remained relatively stable at 22% to 17%. Agriculture and transport sectors consumed only a small percentage of electricity, which remained constant over the years. The total electricity consumption increased from 14,261 GWh in 2019 to 17,547 GWh in 2022, representing a 22.8% increase.

The total amount of electricity lost (i.e., both technical and commercial) annually in distribution was estimated to be about 3,243 GWh in 2019, about 24.6% of the total electricity purchased. The amount of electricity lost increased by about 17.3% to 3,804 GWh, which is 26.19% of the total electricity purchased in 2020. The electricity lost in distribution increased to 4,809 GWh and 5,055, which is about 29.7% and 29.98% of the total electricity purchased in 2021 and 2022, respectively. The total distribution loss is expected to reduce due to interventions such as the ongoing network improvements, installation of smart prepaid meters, and revenue mobilisation exercise being carried out.

These high levels of electricity distribution losses coupled with non-payment of bills and poor tariff structure, have led to a mounting power sector debt and poor financial health. To curtail the mounting power sector debt and poor financial health and thereby increase their revenues, the Utilities have been installing prepaid electricity metering systems for both the private sector and government agencies. The sector is also pursuing other solutions and approaches including the implementation of Energy Efficiency (EE) and Demand Side Management (DSM) measures and reforms in the distribution sector to address the financial health challenges faced by the distribution utilities. These measures are inline with the Governement's policy of improving efficiency in both the supply and demand segments of energy, and also in line with the ESRP's efforts to reduce the energy sector debt.

Electricity Access

The national electrification access rate increased from 85% by the end of 2019 to 88.8% at the end of 2022 with about 1,021 additional communities being connected to the national grid as part of the rural electrification programme. Figure 6 shows the Electricity Access Map of Ghana in 2021.

The population access rate at the end of 2021 was 100% in urban localities as compared to 72.9% in rural localities. Per government policy, the nation expects to achieve universal electricity access by 2025.

To ensure the achievement of the 2025 national access rate target, GoG participated in the World Bank-funded Ghana Energy Development and Access Project (GEDAP). The project, which started in 2007, aims to increase the population's access to electricity and help transition Ghana to a low-carbon economy through the reduction of greenhouse gas emissions among other objectives. The GEDAP project is tailored to expand electricity access to geographical locations such as island communities and those Volta Lakeside communities where the level of electricity demand is low and extending the existing national grid over long distances to reach such communities would not be cost-effective.

Currently, the Government is participating in Scaling-Up Renewable Energy Programme (SREP) programme with the overall goal of significantly contributing to the Government's goal of universal access to electricity through the financial provision of combination of grants, concessional loans, and guarantees. The four components of the programme are the provision of Renewable energy mini-grid and stand-alone PV systems; Solar PV-based net metering with battery storage; Utility-scale solar PV/Wind power generation; and Technical Assistance to scale-up renewable energy sector.

Hence, mini-grids and stand-alone renewable energy solutions were developed to provide needed electricity services to those remote communities to complement the national grid to help move the electricity access rate from about 89% at the end of 2022 to at least 95% by 2025.

3. Planning Environment in Ghana Power Sector

3.1. Planning Challenges

The challenges that affected the effective planning and operation of the country's power system until 2016 have been thoroughly discussed in the 2018 and 2019 IPSMP reports. These challenges, which have shaped the approach of power system planning, are summarized as the following:

(i) Shortfalls in hydropower generation due to climate change, variability in water inflows into the hydro dam reservoirs, and challenges with adhering strictly to reservoir management plans.

(ii) Challenges with the implementation of cost-reflective electricity rate settings.

(iii) Difficulty with the determination of level (quantum) of suppressed demand and street lighting load.

Dealing with Planning Challenges

The 2018 and 2019 IPSMP was developed using a more collaborative approach which was led by the Energy Commission with the active participation of stakeholder institutions such as GRIDCo, ECG, and GNPC, among others. The IPSMP highlighted the need to sustain this collaborative approach. It, therefore, recommended the formation of a technical committee to be known as the Power Planning Technical Committee. This Committee shall be led by EC and GRIDCo and will be responsible for the development of the annual, medium, and long-term electricity generation capacity expansion plans for the country.

Subsequent to the adoption of the IPSMP as the main planning document for the Ministry of Energy, the Minister of Energy, inaugurated the PPTC and members were accordingly sworn-in on 10th August 2020. The objective of the PPTC as contained in its adopted planning guideline is to develop a common least-regrets electricity generation capacity expansion plan for Ghana.

Other recommendations in the 2019 IPSMP report such as competitive procurement of power and fuel led to the formulation and adoption of policies such as the Energy Supply Procurement and the Least-Cost Fuel Procurement policies in 2019. However, the sustainable development of the power system in the future will depend on the sustainability of these implemented policies and strict adherence to good power sector governance as well as strong and capable power sector institutions.

Forecasting Demand

Demand for electricity, both in terms of peak load and total energy demand, is a critical variable that drives decision-making in Ghana's power sector. Forecasting of electricity demand on the grid has been particularly challenging in recent years for several reasons including:

- Uncertainty of industrial and commercial demand uptake, as industries and large commercial customers are more willing to switch to alternative options due to the high tariffs;
- Increasing potential for residential and commercial customers to invest in self-generation through solar PV systems and diesel generators (when electricity prices become favourable);
- Energy efficiency and demand-side management (DSM) measures especially for lighting, cooling, and industrial motors have great potential to reduce demand growth;
- A significant amount of suppressed demand is assumed to be in the system (however, estimating suppressed demand has been a challenge);
- Uncertainty of VALCo's consumption owing to operational challenges and policy; and
- Underutilisation of disaggregated data on consumption (i.e., breakdown of consumptions by different customer classes) from the utilities, which has limited detailed sectoral forecasts and demand analysis.

Detailed analysis of demand forecasts was carried out using historical data collected from ECG, NEDCo, and Enclave Power using improved regression analysis.

Economic growth is a key driver of demand forecasts, and currently, most forecasts rely on the IMF's short- to medium-term economic growth forecasts from which moving averages are derived and applied to extend the forecasts over the planning period. In general, a business-as-usual expectation is that the long-term annual average of the real GDP growth will average around 5.8%.

Increasing average daily temperatures and relative humidity due to climate change requires that demand forecasts consider how climate change could impact potential increased demand for cooling in residential and commercial sectors. Therefore, growth in peak load could be different from the growth in annual or monthly energy demand. This differentiated growth rate between peak demand and annual energy growth could also be exacerbated by increasing penetration of solar power both at the utility and consumer levels.

In addition to GDP, average temperature and relative humidity are used as explanatory variables in forecasting electricity demand. Dummy variables are also used to account for abnormal occurrences on the grid such as periods of power curtailment that suppress electricity demand to a significant extent. Three different forecasts (i.e., reference, high, and low cases) are considered in the IPSMP to address uncertainties.

Energy Efficiency and Demand-Side Management

Energy audits undertaken in various commercial buildings in 2017 under the IRRP project indicated that 10-30% of the electricity used could be saved through cost-effective housekeeping and equipment retrofitting measures, particularly in lighting (e.g., changing light bulbs and fixtures) and cooling, especially in the era of high retail tariffs.

Furthermore, a study completed in March 2019 under the IRRP project to assess Energy Efficiency and DSM Potential in Ghana, showed that the total top energy efficiency opportunities in Ghana amount to a technical energy saving potential of 6,350 gigawatt hours

(GWh), which is about 31.7 percent of total forecasted load in 2021 (20 TWh). However, when several limiting assumptions (e.g., cost of implementation, rate of uptake or level of participation, etc.) are taken into consideration, the achievable energy savings potential in 2021 is 560 GWh, which is equivalent to about 2.8 percent of total forecasted load in that year.

Hence, if the country is able to realize just the estimated achievable energy savings potential, this can reduce the energy demand by about 1.9 terawatt hours (TWh) in 2030, which amounts to about 5.3% of total load forecasted in 2030 (35,634 GWh). However, sustainable policy and regulatory actions are needed to support energy efficiency measures for the realization of the energy savings potential. Although this analysis does not capture all the barriers to the implementation of these measures, the scale of opportunities for energy savings potential identified in Ghana is enough to help policy makers and utilities recognize the importance of energy efficiency measures as a strategy for lowering costs of energy services and for driving economic productivity.

In 2020, a Field Metering and Measurement Studies (FMMS) survey was conducted by Millennium Development Corporation (MiDA) under the Millennium Challenge Compact Agreement. The purpose of the FMMS was to assess household electric appliances' energy efficiency and ownership in Ghana, with the overall objective of strengthening the existing appliance Standards and Labelling (S&L) program that was established several years ago in Ghana. Subsequent to this, the Energy Commission through Parliament included 19 new appliances to the Standard and Labelling program. These appliances include rice cookers, television sets, electric kettles etc. With this, appliances that do not meet the minimum energy efficiency performance standard requirements will be banned from entering the country.

Supply-Side Issues

The supply-side options associated with Ghana's power system are made up of this supply mix: 65.3% thermal power, 34.1% hydro, and 0.55% renewable energy as of December 2021. The main supply issues, in the long term, are enumerated as follows:

Water Availability for Hydropower Generation

The hydrology or annual inflows of the various tributaries of the Volta River into the Volta Lake reservoir provide key indicators for the availability of water for hydropower generation. The water level in the Akosombo Dam has been low in the past (from 2013 to 2015) mainly due to the drafting of the reservoir beyond the recommended levels of generation from the dam. The over-drafting was mainly due to shortfalls in thermal generation because of unreliable gas supply.

The inflow in the 2016 inflow season (i.e., from June to November) was higher than the flows for each of the years between 2013 through 2015; however, it was lower than the long-term average (LTA) by 6%. Challenges with procurement of fuel supply for thermal generation made it difficult to adhere to the recommended reservoir drafting plan, especially at peak periods, thus affecting the reservoir elevation.

The elevation of the Volta Lake at the beginning of 2017 was 250.47 feet, but due to gas supply challenges at Aboadze in the first quarter of 2017, 6 units of the Akosombo plant were operated at peak, which negatively affected the level of the Volta Lake. The inflows in 2017 were lower than the long-term average (LTA) by 7%.

The Volta Lake started the year 2021 at an elevation of 267.7 ft (81.6 m) and ended the year at an elevation of 269.2 ft (82.0 m). The Lake recorded a maximum of 271.3 ft (82.7 m), which is 31.3 ft above the minimum operating level of 240 ft during the 2021 inflow season and a rise of 11.8 ft above the minimum level of 259.6 ft recorded in the year. The total net inflow recorded in 2021 was 31.01 MAF, which implies that an above-average inflow of 30.01 MAF was obtained in 2021.

The Bui Reservoir Elevation at the end of 2021 was 177.58 masl, which is 9.58m above the minimum operating level (168 masl). The maximum level attained during the inflow season was 180.90 masl on October 27, 2021.

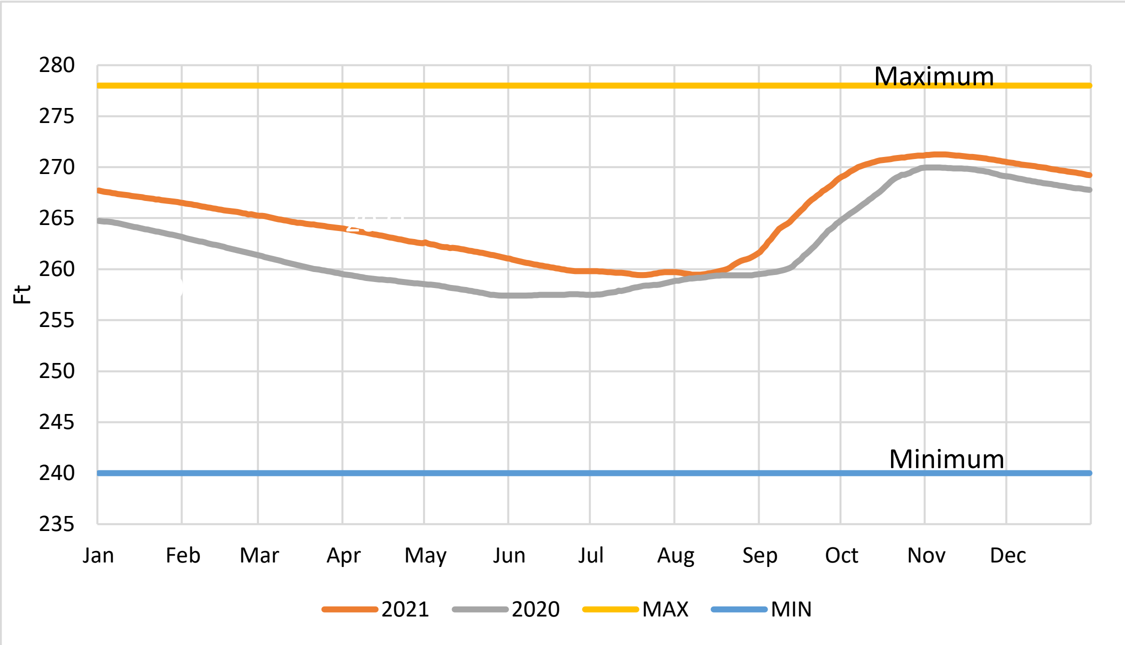


Figure 5: Akosombo Elevation 2021

Source: 2022 Annual Supply Plan

The Bui Reservoir level at the beginning of 2021 was 172.16 masl. Based on the year (2021) start elevation and a plan to adopt a conservative approach towards the reservoir draw down, Bui was expected to operate two (2) units at peak during 2021. However, due to system exigencies, the plant operated off-peak in addition to the peak requirements resulting in the reservoir dropping to a minimum water level of 166.70 masl on June 25, 2021, at the end of the dry season. This was the lowest elevation of the reservoir since the commissioning of the Bui Generating Station (BGS). The minimum level reached was thus 2.7m lower than the projected minimum of 169.40 masl for the year.

The projected and recorded reservoir trajectory in 2020 and 2021 is shown in Figure 6.

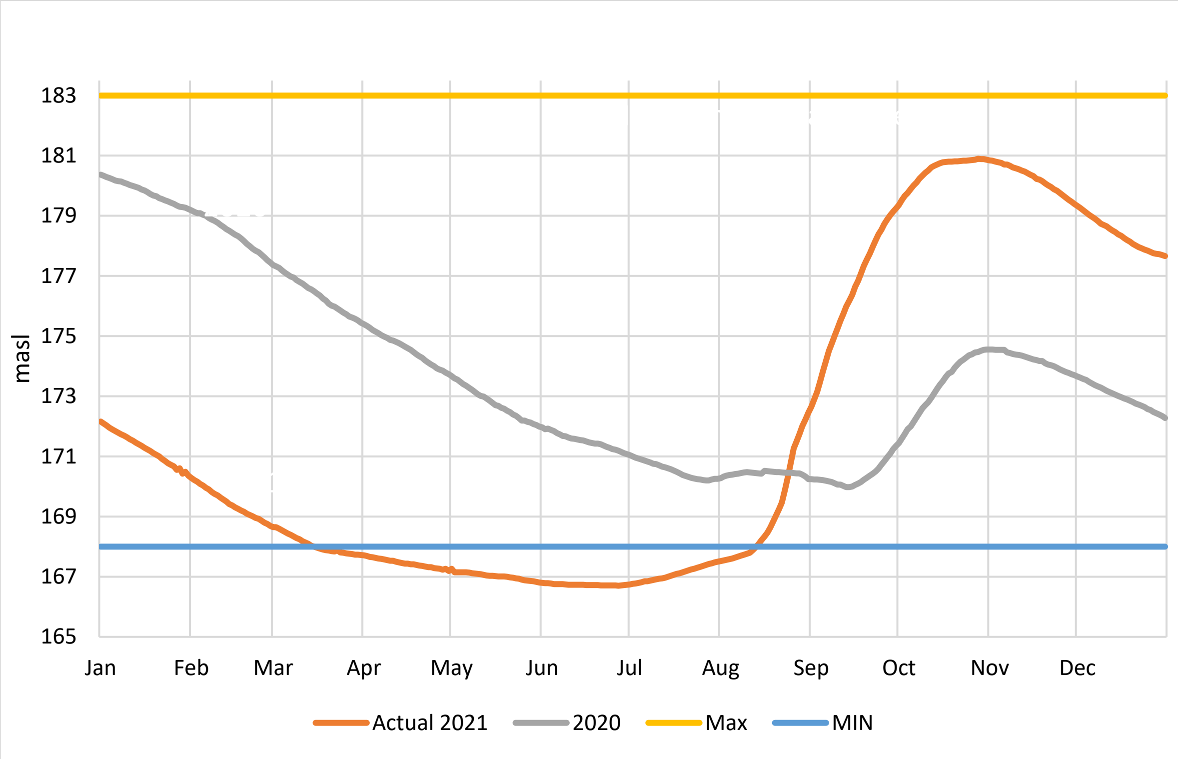


Figure 6: Bui Reservoir Elevation 2020 and 2021

Source: 2022 Annual Supply Plan.

Natural Gas Resource and Infrastructure Constraints

The current natural gas infrastructure that supplies natural gas for power generation includes the three (3) FPSOs producing and exporting gas from domestic sources with the following details:

- FPSO Kwame Nkrumah in the Jubilee field, with a total gas handling capacity of 160 MMscfd.
- FPSO John Evans Atta Mills in the TEN field, with a total gas handling capacity of 100 MMscfd.
- FPSO John Agyekum Kuffour in the OCTP field, with a total gas handling capacity of 210 MMscfd, which is expected to be increased to 260MMscf in the second half of 2023.

Mid-stream infrastructure, operated by the Ghana National Gas Company comprises the following main elements:

- An offshore gas export pipeline, which consists of a 12-inch diameter 58km long subsea pipeline, transporting dense-phase gas from the Jubilee FPSO to the Gas Plant (GPP).
- A Gas Processing Plant (GPP) at Atuabo in the Western Region with a maximum design capacity of 150 MMScfd and a normal design capacity of 120 MMScfd.
- An onshore gas pipeline, which consists of a 20-inch diameter 110 km pipeline, transporting sales gas from the GPP to an existing Thermal Power Plant at Aboadze

- Gas imports from Nigeria flow through the WAGP to Tema and Takoradi. There is also the reverse flow capacity on the WAGP transporting gas from the West to the East. WAGP has the capacity (in both directions) to deliver up to 235MMscfd of gas in Tema and up to 128MMscfd in Takoradi.

Ghana's total proven domestic natural gas reserves as of the end of 2022 was estimated at about 1.772 TCF. In 2021, 107.8 TBtu lean natural gas was produced from domestic gas sources (Jubilee, TEN and OCTP).

Natural gas supplied from domestic sources accounted for 70% of the total in 2019, 79% in 2020 and 85% in 2021 (see **Table 7:** below). The increasing share of natural gas supplied from domestic sources could be attributed to the reverse flow of natural gas from the West to East.

Table 7: Natural Gas Supplies from WAGP, Atuabo GPP and OCTP in MMscf

	2019	2020	2021	2022
WAGP	22,335	22,196	16,975	17,908
Atuabo GPP	19,443	28,423	33,896	37,975
OCTP	32,550	56,571	65,141	67,897
Total	74,329	107,190	116,012	123,780

Source: WAGP, National Energy Statistics, GNGC

The WAGP was originally configured to allow for only a unidirectional flow of natural gas from the Tema end of the pipeline (in the east) to the Takoradi/Aboadze end of the pipeline (in the west). With the discovery of more domestic gas in the west, it became necessary to undertake the Takoradi– Tema Interconnection Project to reverse natural gas flows from domestic sources in the west through the WAGP pipelines to gas demand centres in the east. This project was completed and became fully operational in August 2019, thus improving the reliability of the gas supply to power plants in Tema.

Cost of Fuels for Electricity Generation

Fuel price risk will remain an important factor in the country's power generation activity as the proportion of thermal power generation technology in the generation mix continue to increase. The cost of electricity generation from fossil fuel-based power plants depends to a large extent on the cost of the fuel used (e.g., natural gas, LCO, HFO, and diesel). Domestic gas prices are often linked to annual escalation factors, whilst imported gas prices are often linked to international commodity benchmark prices such as Brent Crude. These prices also often have floors, which limit the extent of price reduction, even when the price indices fall. Hence, the high cost of fuels for thermal power generation has been a key challenge in the Ghana power sector and resulted in overall higher tariffs for consumers.

The delivered cost of natural gas and liquid fuels is relatively high in Ghana—the delivered cost of imported gas through the WAGP is about $8.2/MMBtu.

The price of gas from Sankofa fields, produced, conditioned to pipeline specifications and delivered to the National Transmission System was $8.72/MMBtu in 2022, and US$10.05/MMBtu in 2023. The Jubilee Foundation Volume which GNPC was taking from the Jubilee gas sellers at no cost, was exhausted at the end of 2022. For the first half of 2023, the price for Jubilee/TEN gas was set at US$0.5/MMBtu under an interim arrangement between GNPC and the upstream gas sellers. A long-term price is expected to be agreed between the Parties by the second half of 2023. The costs for gathering and processing increase the delivered cost of Jubilee/TEN. For Q1 2023, the cost of Jubilee/TEN delivered at the gate of the National Transmission System would be $0.93/MMBtu. Transmission costs in Q1, 2023, adds US$0.719/MMBtu to deliver gas at Aboadze, and US$2.5278/MMBtu to deliver further to Tema, from the West. Diesel, HFO, and LCO have relatively higher prices than natural gas, and as such, their delivered cost would be higher than that of natural gas, in the range of $11–$15/MMBtu.

As a result of the high costs of fuels, the national average bulk generation charge (as revised on 1st February 2023)[4] is about GHp 63.1997/kWh[5], which is the weighted average of the cost of both hydro and thermal generation.

Use of Renewable Energy sources for Electricity Generation

The Renewable Energy Act (Act 832 as amended) was enacted to promote the wider-scale utilization of renewable energy sources for energy supply. The Act also specifies Renewable Energy Purchase Obligations (REPOs), which must be fulfilled by utilities and bulk customers.

In February 2019, the Energy Commission released a Renewable Energy Master Plan (REMP), which specified targets for the penetration of specific technologies. The government of Ghana has also made a commitment under the Paris Agreement to “scale up the penetration of renewable energy by 10% by 2030”[6].

Meeting the RE targets would require a significant increase in the deployment of grid-connected renewable energy sources. Since 2019, VRA has installed a 19.5 MW grid-connected solar PV plant at Kaleo (13 MW) and Lawra (6.5 MW) in addition to the 2.5 MW plant at Navrongo to fulfil its RE obligations. Bui Power Authority (BPA) has also secured a bid to install up to 250 MW of grid-connected solar PV also to realize its obligations out of which 51 MW (50 MW ground-mounted and 1MW floating solar) has been commissioned as of December 2022.

In November 2022, the PURC approved the guidelines that set out the principles, methodology and processes for the approval of Net Metering Rates. The guidelines aim to provide PURC with the information it needs to make decisions on rates at which distribution utilities and customer generators shall agree to billing and settlement of energy exchange under the Net Metering Scheme. These guidelines apply to a Public Utility licensed or authorised [7]under any law to own or operate electricity distribution assets or to provide electricity distribution and supply services in the regulated electricity market in Ghana. Similarly, the guidelines also

[4] By Februray 2023,the BGC was Ghp/kWh 85.8447 (https://www.purc.com.gh/attachment/705636-20230124100135.pdf)

[5] Composite BGC (VRA and IPPs) effective 1st September 2022

[6] Ghana’s intended nationally determined contribution (INDC) and accompanying explanatory note, September 2015: https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Ghana%20First/GH_INDC_2392015.pdf

[7] https://www.purc.com.gh/attachment/772548-20221128101136.pdf

apply to renewable energy Customer-generators operating under the Net Metering Scheme and connected to the distribution network in Ghana.

Feasibility studies have established some potential for electricity generation from wind power along the eastern coast of Ghana. A number of licenses for the development of wind projects have been issued by the EC but none has reached financial close phase.

The Government of Ghana plans to construct a Hydro-Solar hybrid system of 60 MW Hydro Power and 50 MW Solar Power at Pwalugu. When completed, the multipurpose dam which includes a 25,000-hectare Irrigation Scheme, in addition to providing hydropower will also help in improving the country's food sustainability.

Nuclear Option for Power Generation

The country's interest in developing nuclear power for peaceful purposes is to provide secure, clean and reliable baseload power, which stimulates industrial and economic growth and is sufficient for export. Its introduction will also bring other non-power benefits such as seawater desalination, hydrogen production, and process heating for industry including glass and cement manufacturing, and metal production[8]. The introduction of nuclear power into the generation mix is to diversify power generation resources and, thereby, enhance the security of power supply in the country.

Nuclear Power for Electricity Generation in Ghana

In May 2007, the Government of Ghana set up a Presidential Committee on Nuclear Power (PCNP) to investigate the role of nuclear power for electricity generation in Ghana. Cabinet decision was therefore taken in 2008 to include nuclear power in the national energy mix following the recommendations made by the Presidential Committee.

A roadmap for the implementation of a Nuclear Power Programme was developed by the Nuclear Power Centre (NPC[9]) of the Ghana Atomic Energy Commission (GAEC) in March 2015. The roadmap projects the addition of about 1000 MW nuclear power generation to the country's electricity generation mix. Figure 7 shows the proposed roadmap for the construction of the first nuclear power plant in the country.

[8] https://www.iaea.org/newscenter/news/the-use-of-nuclear-power-beyond-generating-electricity-non-electric-applications#:~:text=There%20are%20many%20applications%20beyond,refining%20and%20synthesis%20gas%20production.

[9] Nuclear Power Centre has been upgraded to a Nuclear Power Institute in January 2016

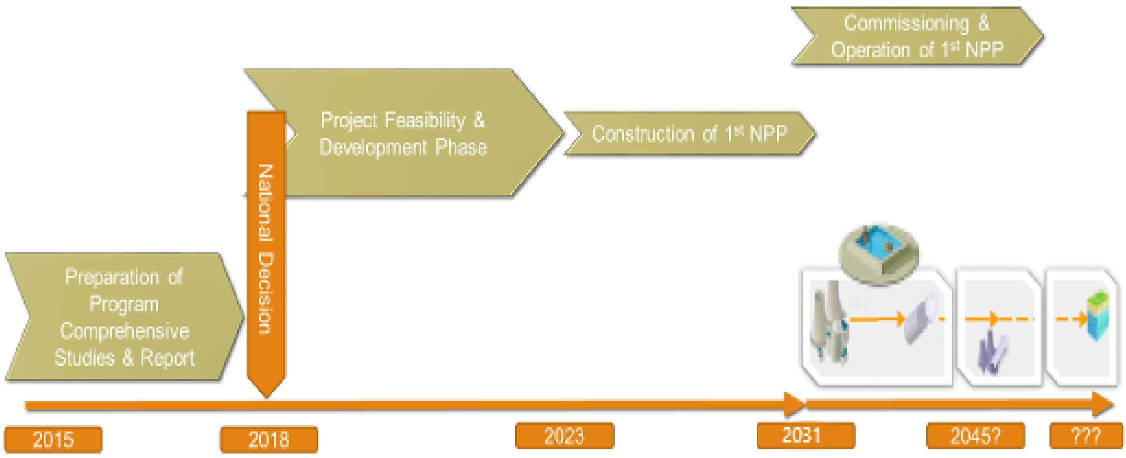


Figure 7:Nuclear Power Roadmap for Ghana

Source: Ministry of Energy, 2022.

In addition to the roadmap, the necessary nuclear legislation (i.e., a comprehensive nuclear law—the Nuclear Regulatory Act, 2015 (Act 895) and a Nuclear Regulatory Authority (NRA)), which are pre-requisites of the IAEA were, respectively, enacted and established in January 2016. The NRA is expected to enforce all nuclear regulations and protocols on safety and safeguards without any political interference or conflicts of interest and ensure effective management of the nuclear project during the construction and in-service operation of nuclear power plants. This is to avoid delays in completion of the project, which otherwise might cause significant increase in the project cost. Government of Ghana has also entered into bilateral discussions with potential suppliers of nuclear technology and fuel to foster cooperation.

Nuclear power plants are expensive to build but relatively cheap to operate because of the low variable cost component. However, in the long term, the high capital costs could be offset by the savings on O&M and fuel costs, especially in situations when the prices of natural gas or coal are relatively higher. The attractiveness and competitiveness of nuclear power is further improved if the social, health and environmental costs associated with fossil fuels are also taken into consideration.

In view of the above, and as part of Ghana's Energy Transition Framework to decarbonise the energy sector, nuclear energy for power generation is expected to account for about 50% of the generation mix in the 2060s. Government in 2022, also, has approved the acquisition of the preferred site to host Ghana's first nuclear power plant as well as large nuclear power technology as the technology of choice for Ghana's first nuclear power plant.

Transmission and Distribution Investments

Investments in technological and operational improvements in both transmission and distribution infrastructure are needed to enhance the delivery of electricity and reduce losses. The challenge in the past and at present is how to obtain sufficient investments in a timely manner to ensure that expansion and upgrade of the network (e.g. K3BSP), and 330 kV Kumasi third Bulk supply point are not delayed. These upgrades will alleviate high loadings of some transformers and increase transfer capacity, especially to the Middlebelt and NEDCo areas. The increased transfer capacity would also support exports of power to Burkina Faso, Mali, and other countries in the subregion. Other challenges in network expansion and upgrades include land acquisition issues, which have continued to hamper timely completion of transmission and distribution infrastructure projects.

Table 8: Transmission and Distribution Losses in Ghana

Indicator	Unit	2016	2017	2018	2019	2020	2021	2022
ECG Distribution Losses	%	23.6	22.6	24.3	24.7	26.6	30.4	30.6
NEDCo Distribution Losses	%	32.1	27.4	31	28.5	27.2	27.4	28.3
EPC Distribution Losses	%	7	1.7	2.7	2.6	2.1	1.2	0.5
Transmission Losses	%	4.4	3.8	4.4	4.7	4.5	5	4.1

Source: 2023 Energy Statistics, Energy Commission

Distribution-level technical and commercial losses continue to remain high, and greater technological and operational improvements are needed over time to reduce these losses. Reliability improvements are particularly critical to ensure that distribution utilities (ECG, NEDCo and EPC) can deliver power reliably to their customers. The distribution utilities, in the last few years, have focused on installing prepaid metres and boundary meters on a massive scale to reduce power and revenue losses; however, more monitoring and analytics are necessary to ensure that power and revenue loss reduction targets are achieved. The timeframe for reducing the power and revenue losses (i.e., technical and commercial) will have an impact on the cost of power to Ghanaians and operational profitability of utilities.

The increasing T&D losses can be attributed to increasing load without the corresponding upgrade and expansion of the network, among others. The overall technical and commercial losses in the power sector were 27% in 2021, costing about USD 700 million annually.

It is worth noting that the losses for Enclave Power Company was relatively lower because of the shorter reach of their distribution network. The losses improved further in 2017 after the installation of a dedicated 161kV/33kV substation within the Free Zones enclave that supplied power to their customers.

Wholesale Electricity Market

In order to improve the general governance and operations of the electricity sector, the Electricity Regulations, 2008, LI 1937, stipulate the establishment and the implementation of a wholesale electricity market (WEM) in Ghana, to facilitate trading in bulk or wholesale electricity, ancillary services, or any other related electricity supply product or service. The WEM is also expected to allow for private-sector investment and competition in the procurement of electricity in Ghana.

The LI 1937 also provided for a number of key policy guidelines:

- The structure of the WEM and the overall rules that govern the WEM; and
- Establishment of an Electricity Market Oversight Panel (EMOP), which would, inter alia, monitor the general performance of electricity transmission utility, ensure smooth and efficient operation of the WEM, monitor pre-dispatch schedules, and ensure long-term optimisation of hydro-electricity supply in the country.

The EMOP was established in December 2017 to supervise the administration and operations of the WEM. The EMOP advises the Energy Commission on the administration of the WEM.

The establishment and implementation of the WEM, the structure of the final market design and the market rules, are still evolving and would be expected to influence the electricity planning environment and landscape.

4. MODELLING FRAMEWORK

4.1. OVERVIEW OF PLANNING TOOL

The main tool used for the modelling and analysis is IPM. It is a proprietary, commercial multi-regional planning model developed by ICF to support long-term planning for the power and industrial sectors. IPM allows for a detailed engineering/economic capacity expansion and production costing model designed to project competitive least-cost generation options for electricity. It is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector.

In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation. In this Ghana IPSMP, the main applications have been capacity planning and analysis of the implications of alternative strategies/policies.

4.1.1. Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period.

IPM employs a bottom-up partial equilibrium and dynamic linear programming model for the optimisation of the electric generation and transmission within each zone/region as well as the transmission lines that connect the zones to meet the electricity demand at the least cost. The model also projects plant generation levels, new power plant construction, fuel consumption, and inter-regional transmission flows using a linear programming optimisation routine with dynamic effects.

The model simulates the operations of a power system in the mid- to long-term planning horizon, which is well suited for scenario analysis, and it has perfect foresight (i.e., IPM looks at future years and simultaneously evaluates decisions over the entire forecast horizon). IPM explicitly considers fuel markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals, as part of its optimisation process.

Figure 8 illustrates the framework of IPM, highlighting the types of inputs and outputs of the model. All existing publicly owned and independent power producer generators are modelled, specifying the operational and contractual constraints for each of the generators.

Outputs of IPM include estimates of regional energy and capacity prices, optimal investment plan including the timing of additional capacity and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, fixed operation and maintenance [FOM], variable operation and maintenance [VOM]), allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Results can be directly reported at the national (summary) and zonal (detailed) levels.

Although the IPM is capable of explicitly modelling individual (or aggregated) end-use energy efficiency investments, this feature was not included in the 2023 IPSMP Update, due to lack of sufficient data on energy efficiency improvement. However, an assessment was conducted to evaluate the potential savings from energy efficiency investments in the future, as discussed in the Appendix. Investments in end-use energy efficiency practices can compete on a level playing field with investments in traditional electric supply options to meet future demands. Consequently, as supply-side resources become more constrained or expensive due to rising fuel prices or implementation of more stringent environmental regulations, it is expected that more energy efficiency would be considered.

4.2. Model Structure and Formulation

The IPM model structure and formulation did not change in this updated version. The objective function is still the same with the main three structural components of the Model being made up of the – objective function, decision variable and set of linear constraints.

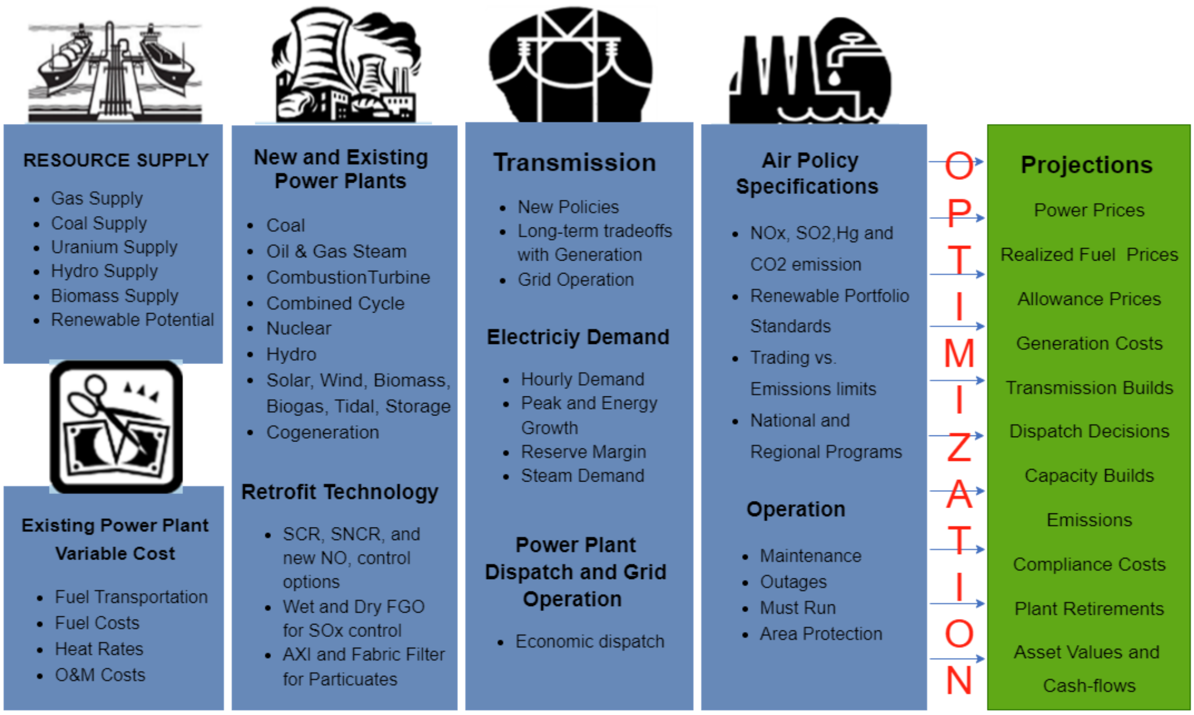
4.2.1. Objective Function

Objective Function for the Integrated Planning Model (IPM®)

Minimize the present value of:

$Total\ Costs = \sum_{years} (GenCosts_i + NewCapCosts_i + TransCosts_i +$
$EmisAllowanceCosts_i + UnservedEngyCosts_i)$Subject to:

- Capacity constraints (available supply to meet peak demand in MW + reserve margin)
- Energy constraints (available supply to meet energy demand in GWh)
- Operational constraints (turn down, area protection, capacity factors, etc.)
- Fuel use constraints (resource volume, pipeline constraints, etc.)
- Emissions constraints (RE targets, GHG emissions limits, etc.)
- Transmission constraints (transfer capability limits, costs, etc.)



*Note: Not all elements mentioned here are included in the Ghana IPM

Figure 8:Framework for Ghana Integrated Planning Model (IPM)

IPM's primary objective over the period of planning is to reduce the total, discounted net present value of the costs of meeting demand, power operation constraints, and environmental regulations. It is the net present value of the sum of all the costs incurred by the electricity sector which is being minimised by the linear programming formulation. The total cost mainly comprises of the cost of new plants, fixed and variable operating and maintenance costs, and fuel costs, among others. User-provided discount rates in the model are used to determine the NPV for all the years over the entire duration of the planning horizon.[10]

4.2.2. Decision Variables

Decision variables are the values which are solved for in the IPM whilst considering the least-cost function and the constraints in the electric system. The results for these decision variables are in effect the optimal least-cost solution given the set of constraints.

The key decision variables represented in the IPM are:

Generation Dispatch Decision Variables: These decision variables depict the generation from each of the model power plants, with each of them, having a respective generation decision variable defined for all possible combinations of fuel, season, model run year, and segment of the seasonal load duration curve applicable. In the objective function, the generation decision variable of each plant is multiplied by the relevant heat rate and fuel price to obtain a fuel cost. In addition, the variables are also multiplied by the respective VOM cost rate to obtain the VOM cost for the plant.

Capacity Decision Variables: This decision variable characterises the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. The decision variables represent the existing capacity and capacity additions which are multiplied by the associated FOM cost rates to obtain the total FOM cost for a plant in the objective function. The capacity addition decision variables are also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

Transmission Decision Variables: This variable characterises the transmission linkages between the various model regions in each of the run years. The total transmission cost across each link is derived by the multiplication of the transmission variables with the variable transmission cost rates in the objective function.

4.2.3. Constraints

The constraint in the *GH-IPM 2023* attempts to replicate the conditions characterising the electricity sector in Ghana with some of the key constraints included in the model listed below:

- reserve margin
- demand
- capacity factor (used only for selected plants)
- turndown/area protection, transmission
- fuel supply constraints

[10] See Section 10.3 of U.S EPA IPM Documentation v6.

4.3. KEY METHODOLOGICAL FEATURES OF IPM

IPM is a flexible modelling tool for obtaining short- to long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen, but they are estimates of what might happen given the assumptions and methodologies used. This section provides an overview of the essential methodological and structural features of IPM that extend beyond the assumptions that are specific to the *GH-IPM 2023*.

4.3.1. Model Plants

Model plants are used in IPM to represent aggregations of existing generating units, to represent retrofit and retirement options that are available to existing units, and to represent potential (new) units that the model can build.

Existing Units: This refers to plants that are already in operation in the country. For the *GH-IPM 2023*, all existing plants as of December 2022, totalling 25, were characterised. The total number of units within these plants 142. For the *GH-IPM 2023,* all the units within a plant are aggregated together, although IPM could model each unit separately or specific units aggregated together in the model.

Firmly Planned Units: IPM categorises the power plants for which commitments have been made as "firmly planned". For the *GH-IPM 2023*, only the three power plants that were physically under construction were categorised as firmly planned. The generation units of these plants were aggregated and modelled, similar to the existing units, except that their online years are 2023 and beyond.

Retrofit and Retirement Options: IPM uses model plants as retrofit and retirement options for existing and firmly planned units. However, this capability of IPM was not utilised in the *GH-IPM 2023 version*—although it is expected to be included in future versions.

Potential (New) Units: Model plants, differentiated by type of technology, regional location, and years available, represent new generation capacity available in each model run. Based on economics or operational constraints (e.g., reserve margin requirements), IPM "builds" one or more of these predefined model plant types by raising its generation capacity linearly, consistent with the objective function and constraints.

In determining whether it is economically advantageous to invest in new plants, IPM considers cost and performance differentials between existing plants and new technologies, expected technology cost improvements (by differentiating costs based on a plant's vintage, i.e., build year), and regional variations in capital costs that are expected to occur over time. However, regional variations in capital cost were not implemented in the *GH-IPM 2023* version.

4.3.2. Model Run Years

IPM makes use of model "run years" to represent the full planning horizon being modelled. Mapping each year in the planning horizon into a model run year enables IPM to perform multiple-year analyses while keeping the model size manageable. Although IPM reports outputs for only model run years, IPM includes the costs in all years in the planning horizon in the cost minimization problem.

4.3.3. Cost Accounting

The cost components considered by the model include the costs of investing in new capacity options, fuel costs, and the operation and maintenance costs associated with unit operations, among others. To ensure technically sound and unbiased treatment of the cost of all investment options offered in the model, IPM also:

- Discounts all costs in the multi-year objective function to a base year, to ensure that inter-temporal cost relationships are recognized.
- Represents capital costs in IPM's objective function as the NPV of levelized stream of annual capital outlays, in contrast to a one-time total investment cost. The payment period is the shorter of the book life of the investment or the years remaining in the planning horizon. This approach avoids presenting artificially higher capital costs for investment decisions in the out years with costs that would be recovered beyond the planning horizon.

The cost components included in the objective function include cost for all years in the planning horizon allowing the model to capture cost escalation accurately.

4.3.4. Modelling Wholesale Electricity Markets

IPM is designed to simulate electricity production activity in a manner that would minimise production costs, as is the intended outcome in WEMs. For this purpose, the model captures transmission costs and losses between IPM model regions;[11] however, because it is a wholesale model, it does not reflect retail distribution costs. However, generation is based on net energy for load,[12] as opposed to delivered sales,[13] and thus implicitly includes distribution losses.

Additionally, the production costs calculated by IPM are the wholesale production costs. Finally, because IPM is forward-looking, the model does not consider embedded costs, such as carrying (capacity) charges of existing units.

4.3.5. Load Duration Curves

IPM uses load duration curves (LDCs) for dispatching of electric generating units. These are created by arranging the hourly chronological electric load data from the highest to lowest (MW) value.

IPM can include any number of separate LDCs for any number of user-defined seasons. A season can be a single month or several months. *GH-IPM 2023* has used months as seasons, so every year has 12 LDCs**.** Figure 9 presents a chronological hourly load curve for the month of January 2010 and a corresponding LDC for that month consisting of 744 hours.

[11] The current version of the Ghana-IPM model does not include any transmission costs or losses between the various model zones. Instead, the losses are included as "demand" on the grid that needs to be met.

[12] Net energy for load is the electrical energy requirement of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

[13] Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

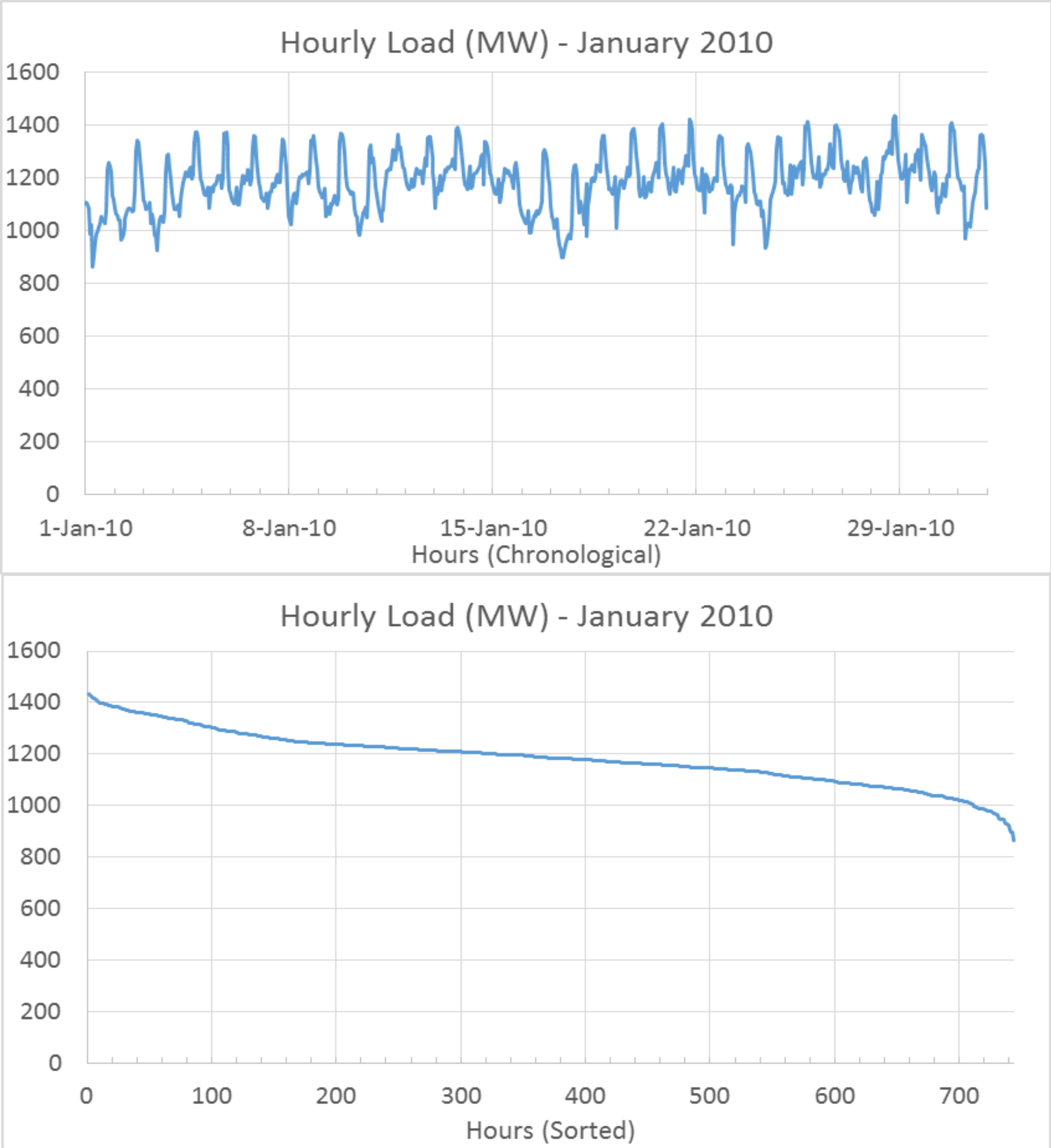


Figure 9: Presentation of Load Duration Curve Used in GH-IPM 2023

Forecasts of peak and total electricity demand and hourly load curves are used to derive future seasonal LDCs for each IPM run year in each IPM region. The results of this process are individualised seasonal LDCs that capture the unique hourly electricity demand profile of each model region. The LDCs change over time to reflect projected changes in load factors. In other words, the baseline LDC is updated each year by the model to account for the new peak demand, and the total energy (area under the LDC).

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 10. ***GH-IPM 2023* uses 10 load segments in its seasonal LDCs for model run years 2023–2040.** Therefore, every year has 120 load segments (12 months x 10 segments). Figure 10 illustrates the 10-segment LDCs used in the model. Length of time and system demand are the two parameters that define each segment of the LDCs.

The load segment represents the amount of time (along the x-axis) and the capacity that the electric dispatch mix must be producing (represented along the y-axis) to meet system load.

Segment 1 in Figure 10 generally contains 1% of the hours in the month (i.e., "season") but represents the highest load demand value. IPM has the flexibility to model any number of load segments; however, the greater the number of segments, the greater the computational time required to reach a solution. The LDC shows all the hourly electricity load levels that must be satisfied in a region in a particular season of a particular model run year. Segment 1 (the "super peak" load segment with 1% of all the hours in the season) and Segment 2 (the "peak" load segment with 5% of all the hours in the season) represent all the hours when load is at the highest demand levels.

Segments 2 through 10 represent hourly loads at progressively lower levels of demand. Plants are dispatched to meet this load based on economic considerations and operating constraints. The most cost-effective plants are assigned to meet load in all 10 segments of the LDCs.

By using monthly LDCs rather than annual LDCs, IPM can capture any seasonal differences in the level and patterns of customer demand for electricity. For example, air conditioner cycling only impacts customer demand patterns during the dry season, in most regions. The use of monthly LDCs also allows IPM to capture seasonal variations in the generation resources available to respond to the customer demand depicted in an LDC. For example, power exchanges between utility systems may be seasonal in nature. This can impact the type of generating resources that are dispatched during a particular season. Further, because of maintenance scheduling for individual generating units, the capacity and utilisation for these supply resources also vary between seasons.

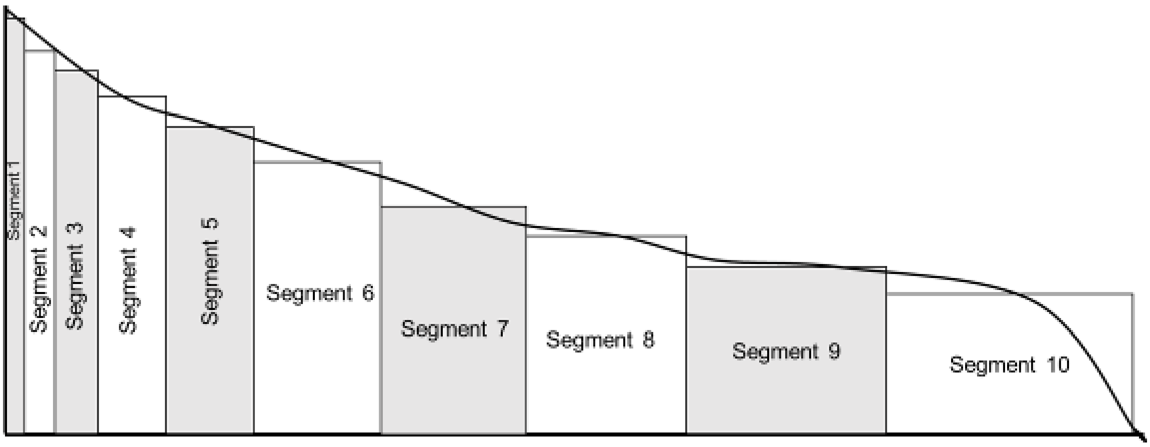


Figure 10: Representation of Load Duration Curve Used in *GH-IPM 2023*

4.3.6. Dispatch Modelling

In IPM, in the absence of any operating constraints, those units with the lowest variable cost are dispatched first. The power plant that generates the last unit of electricity (the marginal unit), sets the energy price for that load segment. Physical operating constraints, for example, turn-down constraints, can influence the dispatch order. These including turndown constraints (to prevent cycling of base load units).

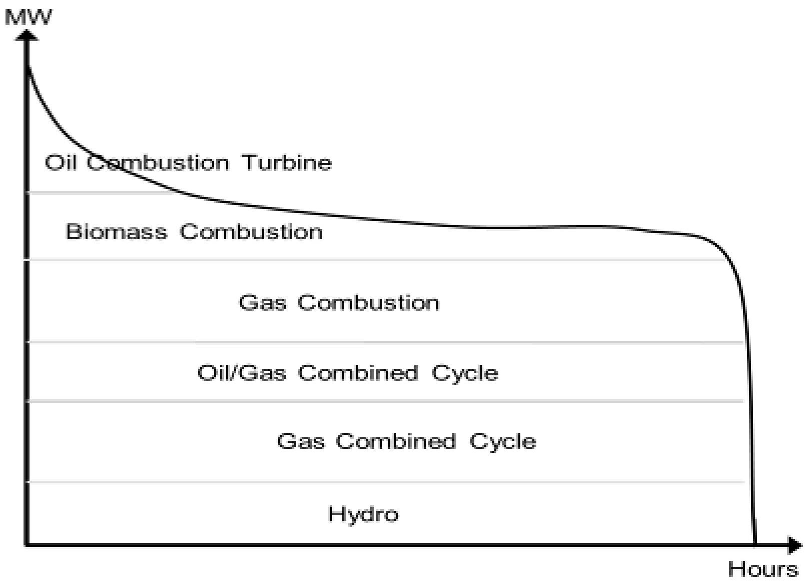


Figure 11: Hypothetical Dispatch Order in *GH-IPM 2023*

Figure 11 depicts a highly stylised dispatch order based on the variable cost of generation of the resource options included in the *GH-IPM 2023*. This shows a hypothetical LDCs with those units with the lowest operating cost being dispatched first for the maximum possible number of hours represented in the LDC because of their low operating costs. Generation resources with the highest variable operating cost (e.g., peaking turbines) are at the top of the dispatch stack as they are dispatched last and for the minimum possible number of hours.

4.3.7. Unserved Energy

IPM will allow unserved energy in the problem optimization if all possible lower cost generation options have been exhausted. Typically, the value of unserved energy is set equal to ten times the variable cost of the most expensive option or a user-specified unserved energy for specific model regions. For the Ghana analysis, the cost of unserved energy is based on an assessment of the value of loss load (VoLL) for different customer classes (see Section 5.3.3). Because cost of unserved energy is usually very high, all units will be dispatched before energy is left unserved.

4.3.8. Fuel Modelling

IPM allows for the modelling of the full range of fuels with the cost, supply, and characteristics of each fuel defined during model set up. In the *GH-IPM 2023***,** all fuel prices are exogenous and are inputs into the model, with the supply volumes for some of the fuels, such as natural gas and biomass, being constrained by resource and production expectations**.**

4.3.9. Transmission Modelling

IPM includes a detailed representation of existing transmission capabilities between model zones. The maximum transmission capabilities between zones are specified in IPM's transmission constraints. The GH-IPM allows for the building of new transmission lines if needed in any specific run year.

The decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition.

4.3.10. Perfect Competition and Perfect Foresight

IPM methodology assumes perfect competition and models the production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The formulation assumes no market imperfections, such as market power, transaction costs, informational asymmetry, or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets.

IPM's assumption of perfect foresight implies that decisions today reflect knowledge of the nature and timing of conditions in future years. For example, IPM's decisions reflect complete foreknowledge of future electricity demand, fuel supplies, and other variables (including regulatory requirements) that are subject to uncertainty and limited foresight. Modellers frequently assume perfect foresight to establish a decision-making framework that can estimate cost-minimising courses of action, given the best-guess expectations of these future variables that can be constructed at the time the projections are made. One can then use scenarios and sensitivity analyses to assess implications of changes to these assumptions.

4.4. Data Parameters for Model Inputs and Outputs

4.4.1. Model Inputs

IPM requires input parameters that characterise the Ghana electric system, economic outlook, fuel supply, and existing energy policies. Below is a list of the key input parameters for the IPM:

Electric System

- Existing generating resources
- Plant capacities
- Heat rates
- Maintenance schedule
- Forced outage rate
- Minimum generation requirements (turn down constraint)
- Fuels used
- FOM and VOM costs
- Emissions Limits or Emission Rates for NO_x, SO_2, CO_2
- Output profile for non-dispatchable resources

New Generating Resources

- Cost and operating characteristics
- Performance characteristics
- Limitations on availability

Other System Requirements

- Inter-regional transmission capabilities
- Reserve margin requirements for reliability
- Area protection
- System-specific generation requirements

Economic Outlook

- Electricity demand
- Firm regional electricity demand
- Load curves
- Financial outlook
- Capital charge rate
- Discount rate
- Fuel supply
- Fuel supply curves
- Fuel price
- Fuel quality
- Transportation costs for natural gas, and biomass

4.4.2. **Model Outputs**

IPM produces a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Standard IPM reports cover the following topics:

- Generation
- Capacity mix
- Capacity additions and retirements
- Capacity and energy prices
- Power production costs (capital, VOM, FOM and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_x, SO_2, CO_2)
- Emission allowance prices

5. Modelling Assumptions

This chapter presents a summary of the various assumptions that guided the modelling work using the IPM. The chapter also describes several sensitivities on key variables that were tested. Detailed information on these assumptions are available on the EC's website.

The modelling parameters used for the IPSMP modelling are as follows:

- Modelling zones
- High-level Assumptions
  - Year maps
  - Financing
- Demand
  - Peak and energy by zones
  - Sensitivities
  - Hourly demand
  - Limitations
- Supply
  - Existing and firmly planned capacity
    - Unit types, cost, operational characteristics and constraints
  - Cost and performance of new generation options
    - Unit types, cost, operational characteristics and constraints
  - Renewable energy resources and renewable energy penetration assumptions
  - Sensitivities
  - Reserve margins
  - Fuel supply and price
    - Natural gas volume and infrastructure
    - Price and volume sensitivities
    - Conventional fuels (liquid fuels, coal, nuclear)
- Transmission

5.1. Ghana Zones for IPM Modelling

Understanding locational differences in a power system landscape is a key element to better planning of generation resources, as it helps in understanding:

(1) Where power plants should be located,

(2) The implications of transmission constraints within and across regions and options to reduce the transmission bottlenecks, and

(3) The assessment of locational marginal pricing is a key element of WEMs.

Current transmission constraints within and across some segments or corridors of the Ghana transmission grid system were evaluated using a transmission load flow model—PSS/E. The results of the transmission constraints evaluation, combined with other data, informed the demarcation of the transmission grid system into four "zones" for the IPM modelling: SouthEastGH, SouthWestGH, AshantiGH,[14] and NorthGH (see **Figure 12** and **Table 9**).

[14] AshantiGH zone represents the Middlebelt areas of Ghana.

The SouthEastGH zone of the IPM model comprises Volta and the Eastern and Greater Accra regions, while the SouthWestGH zone comprises Western and Central regions (which are two zones covered by Electric Company of Ghana [ECG] sub-regions). The AshantiGH zone of the IPM model covers the existing ECG Ashanti operational subregion and the NorthGH zone covers the NEDCo operational area, which includes the Bono, Bono East, Ahafo, Northern, Upper East, and Upper West Regions.

For each of these zones, energy and peak demand forecasts were exogenous inputs that were estimated. Electricity demand for bulk customers in each of these IPM model zones was separately determined because their historical demand data does not lend itself to time-series analysis. Similarly, the demand (energy and peak) for VALCo and Enclave Power Company (EPC) loads were treated separately.

Table 9: Description of Ghana Model Zones and Regions

Ghana Zone	Model Region	Geographical/Demand Coverage
SouthEastGH	SouthEastGH	ECG – Volta, Oti, Greater Accra and Eastern operational regions
	BulkCust – SouthEastGH	Non-ECG bulk customers in Volta, Oti, Greater Accra & Eastern regions
	EPC	Free Zones Enclave in Tema
	VALCO	VALCO plant in Tema
SouthWestGH	SouthWestGH	ECG – Central, Western North and Western operational regions
	BulkCust – SouthWestGH	Mines and other direct customers in Central, Western North & Western regions
AshantiGH	AshantiGH	ECG – Ashanti operational region
	BulkCust – AshantiGH	Mines and other direct customers in ECG Ashanti operational region
NorthGH	North GH	NEDCo operational area, covering Bono, Bono East Ahafo, Northern, Savannah, Upper East, North East and Upper West regions
	BulkCust – North GH	Mines and other direct customers in NEDCo territory
Togo	Togo	Power exchange with Southern and Northern Togo
Cote d'Ivoire	Cote d'Ivoire	Power exchange with Cote d'Ivoire
CLSG	CLSG	Power exchange with Liberia, Siera Leone
Mali-Burkina	Burkina East	Power exchange with Ouagadougou, Burkina Faso
	Mali-Burkina West	Power exchange with Bobodilassou (Burkina) and Bamako (Mali)

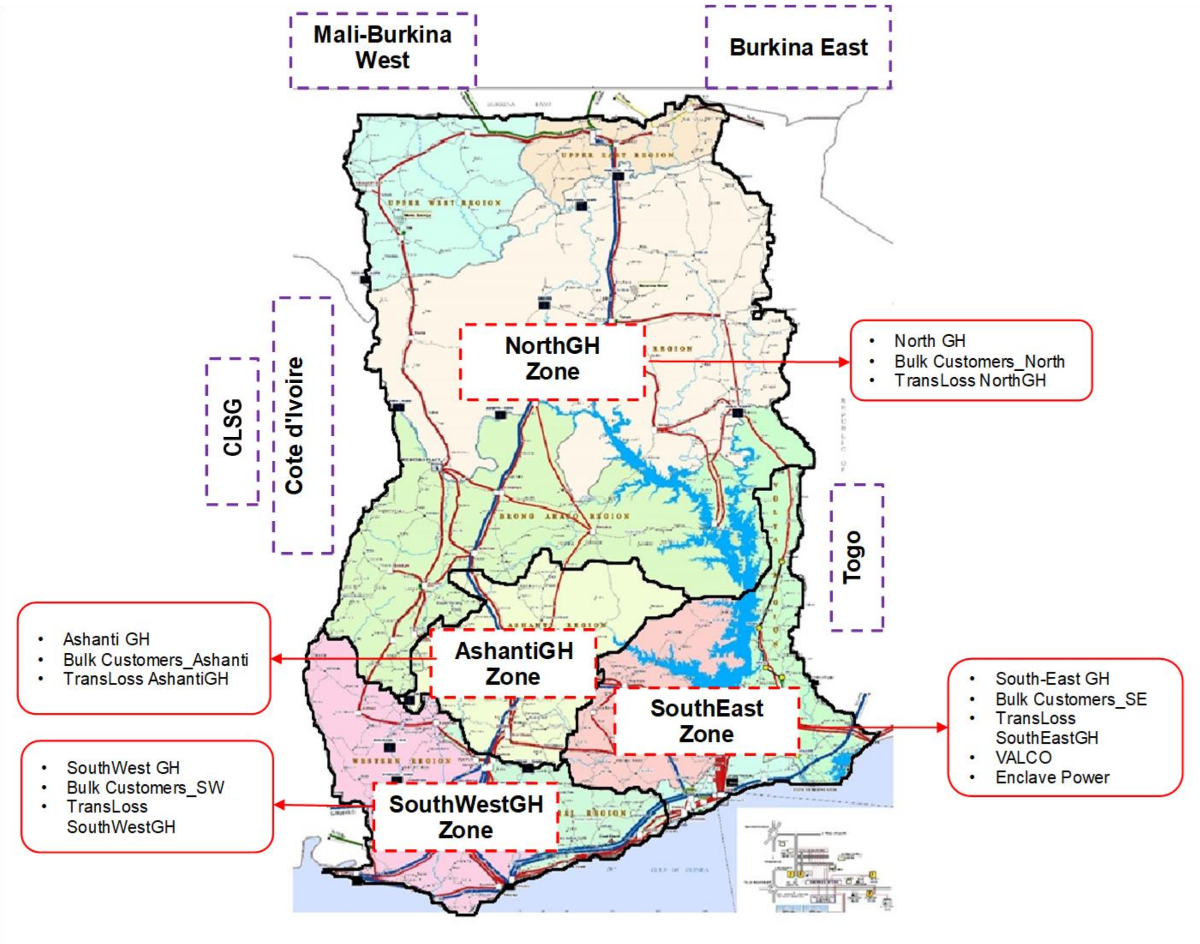


Figure 12: Ghana Zones and Modelling Regions

Source: IRRP Project/PPTC, based on GRIDCo transmission map.

5.2. HIGH LEVEL ASSUMPTIONS

5.2.1. Run Years and Mapping

As discussed in section 4.3.2, the IPM model uses the concept of "run years" to reduce the size of the model in order to maintain a reasonable run-time for solving the model. The mapping of the calendar years to run years is shown in Table 10. As noted earlier, although the model only solves for the outputs in these run years, the objective function is based on costs in all of the years. The run years used in the model are 2023, 2024, 2025, 2026, 2027, 2028, 2029, 2030, 2031, 2032, 2033, 2034, 2035, and 2040.

The analysis time horizon for GH IPM 2023 extends from 2023 through 2040, with IPM seeking the least cost solution that meets all constraints and minimizes the net present value of system cost (i.e., sum of capital, VOM, FOM, and fuel costs). The years designated as "model run years" and the mapping of calendar years to run years are shown in Table 10.

Furthermore, the *GH-IPM 2023v1* uses 12 months and 10 segments for the load duration curve of each month, meaning that for each of the run years, the model outputs can be obtained for 120 parts of the run year. See section 4.3.5.

Table 10: Year Map used in *GH-IPM 2023*

Run Year	Years Represented	Number of Years
2023	2023	1
2024	2024	1
2025	2025	1
2026	2026	1
2027	2027	1
2028	2028	1
2029	2029	1
2030	2030	1
2031	2031	1
2032	2032	1
2033	2033	1
2034	2034	1
2035	2035	1
2040	2036-2040	5

5.2.2. Financial Assumptions

In terms of cost calculation, the GH IPM 2023 uses real 2016 dollars (2016$) as its real dollar baseline. So, all costs are presented in 2016$.

As discussed earlier, the capacity expansion and least cost dispatch decisions are based on minimizing the net present value of capital plus operating costs over the full planning horizon. The net present value of all future capital and operating costs is determined with the use of a discount rate. The real discount rate is assumed to be 10% for the *GH-IPM 2023* model, and is based on the real weighted average cost of capital (WACC).[15] WACC for all future power plants is different, based on specific assumptions about debt-to-equity ratios, and the loan interest rate and rate of return on equity.

In order to levelise the capital costs of new power plants and transmission lines, a capital charge rate (CCR) is applied to the total investment cost (overnight costs + interest during construction) of the new plant/transmission line. CCRs are a function of the underlying discount rate, plant life, debt life, taxes and insurance costs, and depreciation schedule, for each asset.[16] Also, there are technology-specific CCRs based on the specific financial characteristics of the plants, as indicated in the table below.

Additional analysis of the financial costs of new power plants and transmission lines is necessary in order to improve the discount rate and CCR for different types of new power plants and transmission lines.

[15] See Chapter 10 in U.S. EPA IPM Documentation. https://www.epa.gov/sites/production/files/2018-06/documents/epa_platform_v6_documentation_-_all_chapters_june_7_2018.pdf

[16] See section 10.9 of U.S. EPA IPM Documentation. https://www.epa.gov/sites/production/files/2018-06/documents/epa_platform_v6_documentation_-_all_chapters_june_7_2018.pdf

Table 11: Financial Assumptions for New Power Plants

Technology	Lifetime (yr)	Equity Rate	Equity Ratio	Debt Rate	Debt Life (yr)	Real CCR
Combined Cycle	30	18%	30%	10%	15	13%
Combustion Turbine	20	18%	30%	10%	10	14%
Coal Power	40	18%	30%	12%	15	14%
Solar PV Utility	30	15%	30%	8%	15	11%
Wind	30	18%	30%	10%	20	13%
Nuclear Power	60	18%	10%	7%	20	9%
Biomass	30	18%	30%	10%	15	13%
Small Hydro	60	18%	10%	7%	20	9%

Expected future tariffs for Solar in early 2020s: Nominal 8.5 US cents flat over PPA period

Expected future tariffs for Wind in early 2020s: Nominal 9.0 US cents flat over PPA period

5.3. DEMAND

A key element of power sector modelling and planning is the evaluation of the long-term peak load and energy demand forecasts, which is undertaken with Ghana's power sector utilities. Generally, the power utilities in Ghana have so far adopted a top-down econometric approach to forecast demand, which considers actual consumption and constraints associated with each utility. In forecasting demand using an econometric model, power utilities rely mostly on regression analyses based on historical electricity consumption data.

There are three power utilities that operate in Ghana. These are the Electricity Company of Ghana (ECG), Northern Electricity Distribution company (NEDCo) and Enclave Power Company (EPC). The load of the distribution companies adds up to about 75% of the load on the NITS. Thus, demand forecast for the major distribution companies (i.e., ECG and NEDCo) was based on regression analyses.

For both of the utilities, regression analyses were used to determine the relationship between historical annual energy consumption and macro-economic indicators such as GDP, Population growth (Customer Population) and Price of electricity, after accounting for technical losses. The relationship derived was used to forecast the annual electricity demand using projected GDP, Customer Population growth and Price of electricity.

The annual future energy demand from the grid for ECG's operational area was split among the modelling zones, based on the expected ratios of ECG's load centres. The energy purchases forecast for the NEDCo region was assigned to the NorthGH zone.

Future energy demand for bulk customers in each zone was estimated based on forecast received from GRIDCo's bulk customers who are directly connected to the transmission grid. Finally, the transmission losses for each IPM model zone were estimated and added to the projected demand for each IPM model zone.

The energy demand projections for ECG and NEDCo were converted to peak demand forecasts using system load factors for the respective utilities.

5.3.1. VALCo Assumptions

As part of Government of Ghana's policy to develop an Integrated Aluminium Industry in Ghana, the Volta Aluminium Company Limited (VALCO) projected to operate at 150 MW, increasing to 300 MW in 2023 and further increasing to 500 MW by 2024. Upon the completion of the expansion works of VALCO by 2027, the maximum demand is projected to be about 1,000 MW.

It is worth noting that, the operations of VALCO are dependent on factors such as the availability of low-cost electricity, the prevailing price of aluminium and government policies. In recent times, the price of aluminium has been low. However, government considers VALCO as a strategic industry and therefore, gave legacy hydro at a cost of 3.5 UScent/kWh for VALCO's operations for a demand up to 150 MW and valid until end of 2023. The decision was not specific on the price beyond 2023 and for VALCO demand beyond 150 MW.

In view of these and for the purpose of this report, VALCO's demand for the reference case was set to a maximum of 165 MW throughout the planning period (See Table 12). The 500 MW for VALCO is therefore considered under the High demand case.

Therefore, projections for VALCo's energy and peak demand were determined in discussions with VALCo, and are as shown in Table 12. For the short term, VALCO's consumption is assumed to follow the historical consumption for the past 5 years. The utilization of two out of VALCo's five potlines has been assumed for the medium to long term planning horizon due to prevailing conditions at VALCO; however, these assumptions can regularly be updated to reflect actual and realistic changes.

Table 12: VALCO Peak and Energy Forecast

Year	VALCO Forecast	
	MW	GWh
2023	95	861
2024	95	861
2025	95	861
2026	165	1371
2027	165	1371
2028	165	1371
2029	165	1371
↓	↓	↓
2040	165	1371

5.3.2. Ghana Import-Export Assumptions

Ghana has power supply transactions with its neighbouring countries, namely Cote d'Ivoire, Burkina Faso and Togo/Bénin and recently Liberia and Siera Leone. The transaction between Cote d'Ivoire and Ghana is a power exchange arrangement, while Sonabel (Burkina Faso) and Communauté Electrique du Bénin (CEB; in Togo/Bénin) have power purchase agreements (PPAs) with Ghana. Generally, Ghana has been a net exporter over time when all the transactions are considered as shown in Figure 13, although, during periods of generation deficiencies, Ghana has been a net importer.

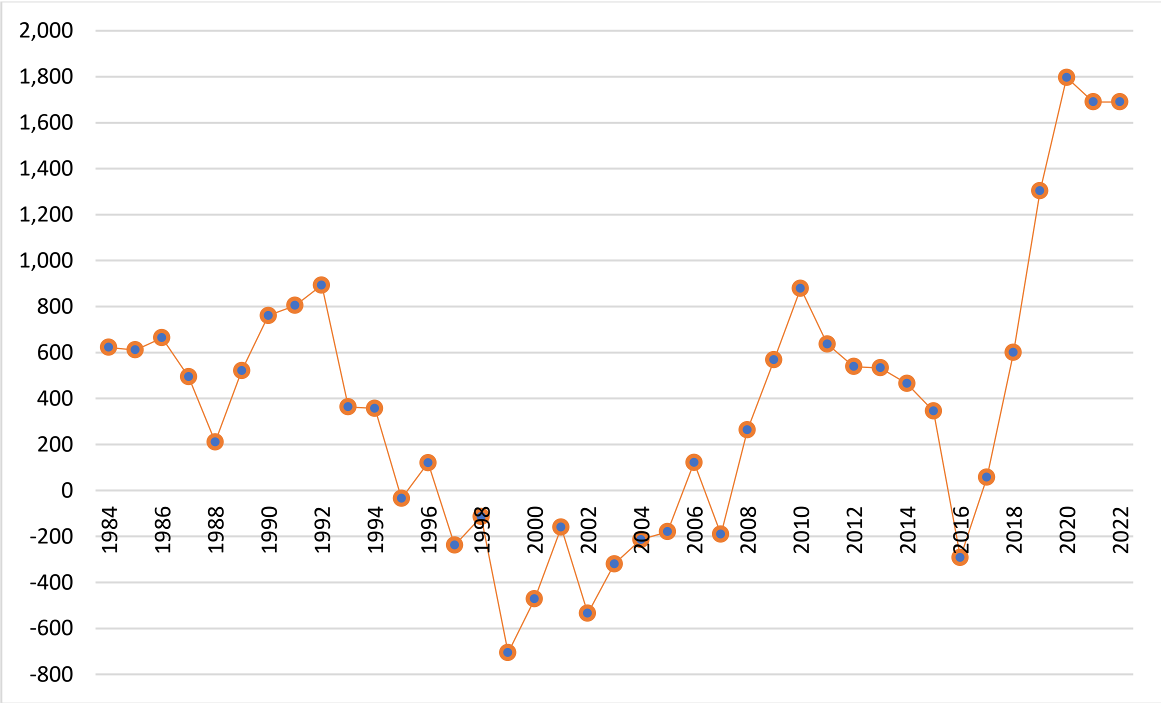
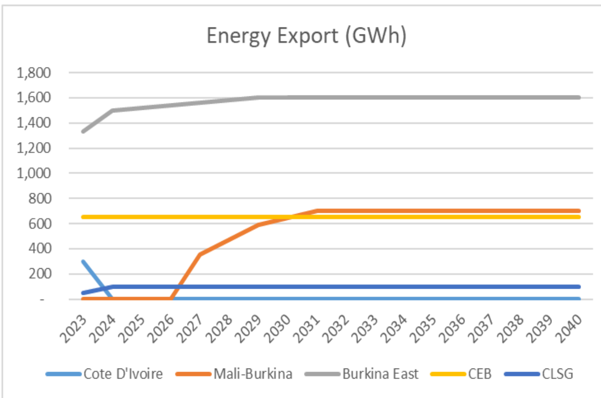


Figure 13: Historical Ghana Net Exports

Source: GRIDCo Transmission Master Plan, 2011 and 2023 National Energy Statistics.

Future expectations for electricity demand projections for net exports from Ghana are primarily based on power supply contracts between Ghana and its neighbouring countries, and these power supply contracts are reviewed on an annual basis to reflect the changing demands of the countries. For the IPSMP modelling, demand forecasts for exports to Togo/CEB, Burkina Faso, CIE, and Mali were determined based on information from GRIDCo and VRA. The projected export for Reference Case is shown in Figure 14.



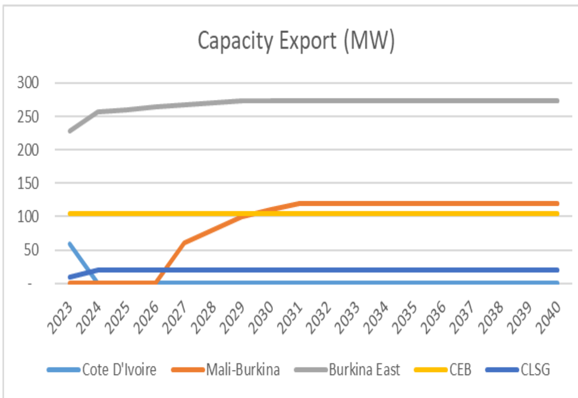


Figure 14: Projected Energy and Peak Exports

These estimates were developed following a series of discussions with GRIDCo and VRA to utilise information on recent forecasts and expected demand growth made available by consumers in these countries to the Ghana utilities.

Energy exports are projected to increase steadily in the near term from about 2,330 GWh in 2023 to about 3,054 GWh in 2031, and is not expected to afterwards. A similar trend is observed in the peak demand exports, which are expected to rise from about 402 MW in 2023 to about 519 MW by 2040. In the long term, countries for which export assumptions have been made are expected to be less reliant on exports from Ghana.

Table 13 and Table 14 illustrate the Reference Case IPSMP energy and peak demand forecasts, respectively, for the different sectors.

Table 13: Energy Demand Forecast

SUMMARY Annual Wholesale Generation Requirement [GWh]									
Year	ECG	NEDCo	EPC	Bulk Customers	VALCO	Exports	GRIDCO Trans Loss	Total Ghana	Total Domestic Ghana
2023	15,375	1,908	289	1,833	861	2,330	1,021	23,616	20,426
2024	16,175	2,050	307	2,103	861	2,250	1,126	24,871	20,634
2025	17,016	2,135	319	2,557	861	2,270	1,050	26,208	22,027
2026	18,078	2,215	414	3,191	1,371	2,290	1,123	28,682	23,898
2027	19,206	2,312	430	3,298	1,371	2,662	1,236	30,516	25,247
2028	20,404	2,424	538	3,279	1,371	2,800	1,300	32,117	26,646
2029	21,678	2,534	552	3,352	1,371	2,937	1,384	33,808	28,115
2030	23,030	2,734	689	3,370	1,371	2,996	1,443	35,634	29,824
2031	24,467	2,863	707	3,337	1,371	3,054	1,501	37,301	31,374
2032	25,994	3,029	883	3,554	1,371	3,054	1,577	39,463	33,461
2033	27,616	3,145	905	3,595	1,371	3,054	1,642	41,329	35,261
2034	29,340	3,299	1,132	3,551	1,371	3,054	1,711	43,457	37,321
2035	31,170	3,462	1,160	3,509	1,371	3,054	1,748	45,474	39,301
2036	33,115	3,634	1,450	3,459	1,371	3,054	1,859	47,944	41,659
2037	35,182	3,817	1,486	3,412	1,371	3,054	1,939	50,262	43,897
2038	37,377	4,011	1,858	3,355	1,371	3,054	2,024	53,050	46,601
2039	39,709	4,217	1,904	3,301	1,371	3,054	2,113	55,670	49,132
2040	42,187	4,435	2,380	3,235	1,371	3,054	2,206	58,870	52,238

Table 14: Peak Demand Forecast

Year	ECG	NEDCo	EPC	Bulk Customers	VALCO	Exports	GRIDCO Trans Loss	Total Ghana
2023	2,348	314	67	332	95	340	177	3,673
2024	2,462	330	66	307	95	382	203	3,845
2025	2,590	344	73	380	95	385	189	4,056
2026	2,752	357	80	459	165	388	202	4,403
2027	2,923	372	88	469	165	452	223	4,692
2028	3,106	390	97	467	165	475	234	4,934
2029	3,299	408	106	479	165	499	250	5,206
2030	3,505	440	117	482	165	509	260	5,479
2031	3,724	461	129	476	165	519	271	5,744
2032	3,956	488	141	519	165	519	284	6,073
2033	4,203	506	158	516	165	519	296	6,364
2034	4,466	531	177	510	165	519	308	6,677
2035	4,744	557	199	505	165	519	315	7,004
2036	5,040	585	223	498	165	519	335	7,365
2037	5,355	615	249	491	165	519	350	7,744
2038	5,689	646	279	484	165	519	365	8,146
2039	6,044	679	313	476	165	519	381	8,577
2040	6,421	714	350	468	165	519	398	9,035

5.3.3. Domestic Demand Sensitivity

Given that any demand forecast can never be predictive (given the high range of uncertainty in underlying factors), it is important to develop various sensitivities to the reference demand forecasts. For the IPSMP, two different demand cases were developed—a high and a low demand case—relative to the Reference Case.

Figure 15 shows the ensuing total energy demand projections. The energy demand projections were converted to peak forecasts using load factors, as in the Reference Case, depicted in Figure 16

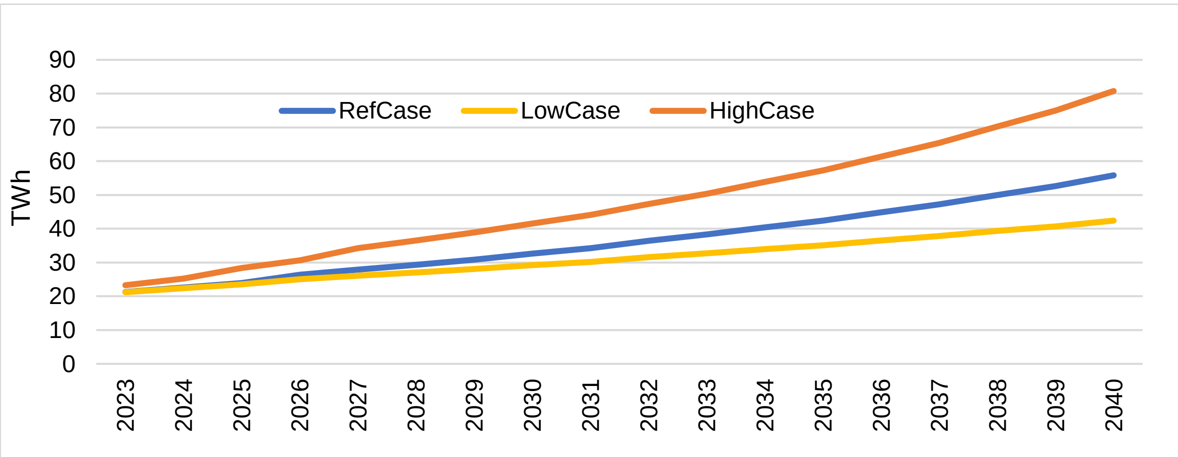


Figure 15: High and Low Energy Demand Forecasts

These cases had different forecasts for the ECG and NEDCo demand areas, based on different expectations of future GDP growth, and other variables such as customer population, and price as explanatory variables.

Demand scenarios for EPC were provided by the company. The demand projections for VALCO, the bulk customers, and exports were provided by their respective entities.

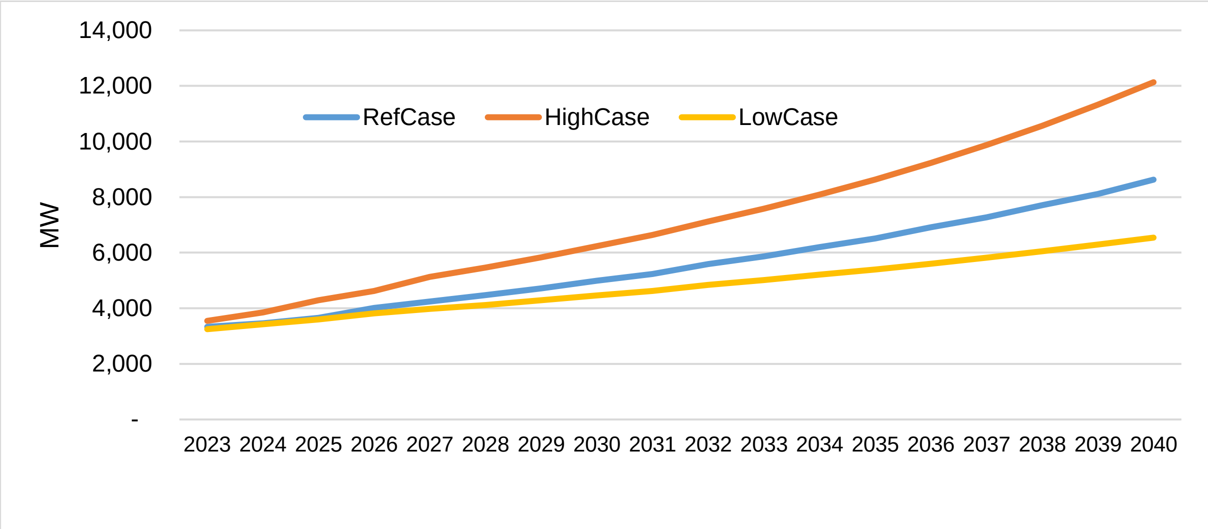
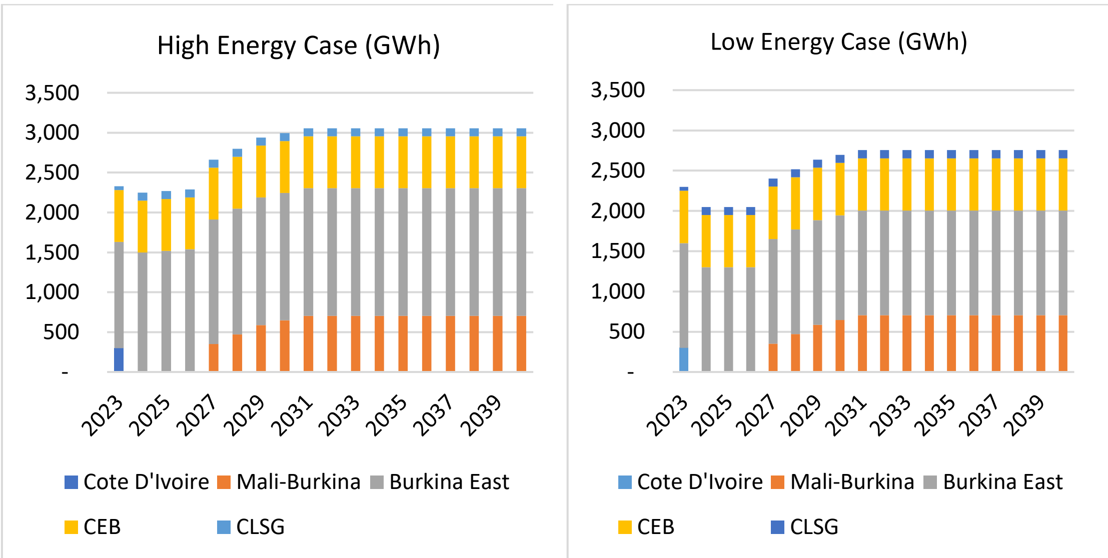


Figure 16: High and Low Total Peak Demand Forecasts

5.3.4. Export Demand Sensitivity

In assessing various demand sensitivities, increased and reduced peak and energy demand export estimates were developed for all three export destinations. Figure 17 illustrates the increased and reduced estimates.



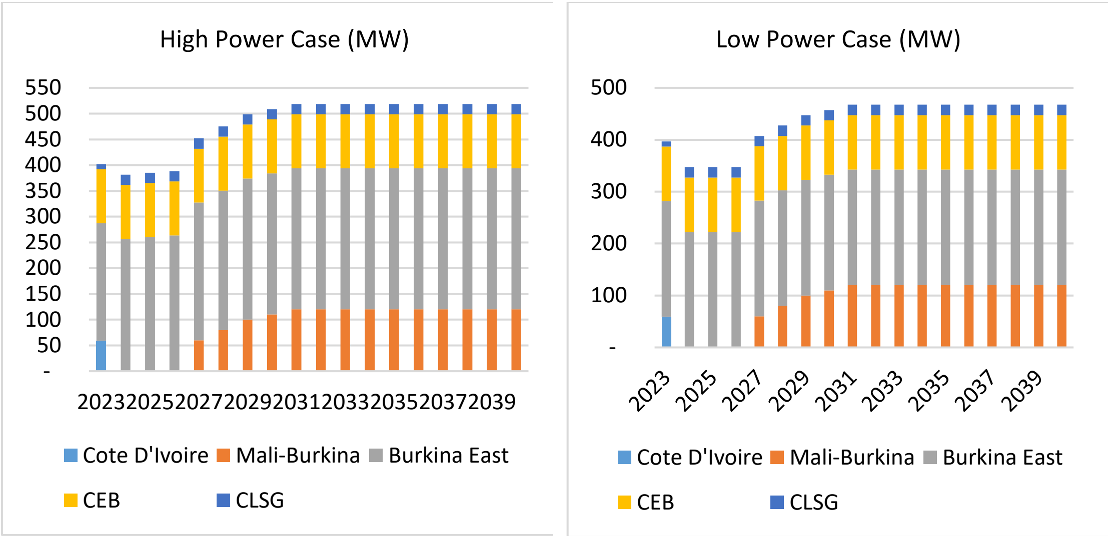


Figure 17: Increased and Reduced Energy and Peak Demand Exports

5.3.5. Hourly Demand – Load Duration Curves

For modelling purposes, IPM utilises a reference year's hourly load duration curve (LDC) to group similar demand and dispatch hours in the optimisation problem (see Section 4.4.5). The highest point on the LDC is the peak demand for the year, and the area under the curve is the total energy demand for the year. IPM takes this reference LDC shape and "grows" the LDCs to a new set of hourly load data based on the peak and energy demand forecasted for the forecast year.

Current available data did not allow the IPM modelling team to determine LDCs at a zonal level. Therefore, all four zones used a common LDC based on the chronological hourly load data from 2018 for all of Ghana, which was provided by GRIDCo. Similarly, the 2016 hourly demand data for all mining companies was also used as the hourly demand for bulk customers. For VALCo, a 7-day hourly demand data was collected and used as a proxy for the entire year given their production pattern. Finally, hourly data were received from EPC for the load served in 2016, and were used as the reference LDC for the EPC model region.

Figure 18 shows the final LDCs derived from the hourly data. For the *GH-IPM 2023*, the reference load shape was not varied over time. In other words, although in the long term, the hourly load shapes could vary (e.g., due to greater industrialisation or higher penetration of air conditioners), this potential change was not considered in the current version.

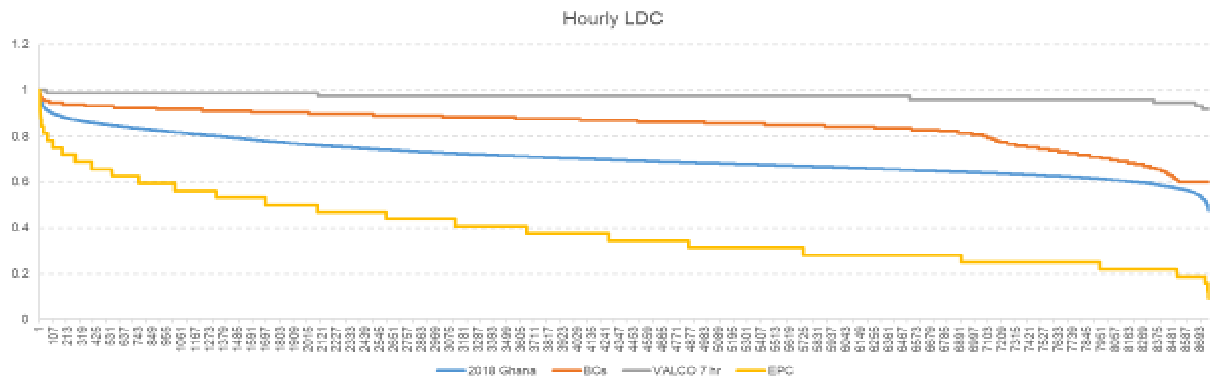


Figure 18: Load Duration Curves scaled to a 1000 MW Peak

5.3.6. Cost of Unserved Energy

The cost of unserved energy in the *GH-IPM 2023 model* is the same as what was used in the 2019 IPSMP which was based on a 2013 report on ECG System Reliability Assessment. The Study provided estimates of the value of lost load (VoLL) by different types of customers, which is shown in Table 15. These values were used as inputs on the cost of unserved energy for various IPM model regions.

Table 15: Cost of Unserved Energy used in GH-IPM 2023

	Cost of Unserved Energy ($/MWh)
ECG and NEDCo model regions	8.11
Bulk Customers and VALCo	14.23

5.3.7. Limitations of IPSMP Demand Forecasting

It is important to recognise that the historical measured electricity consumption does not reflect the full consumption (or demand) of all grid-connected consumers in Ghana mainly due to self-generation. In addition, any potential generation, transmission, or distribution disruptions (i.e., outages) or constraints would also limit the measured consumption. The price of electricity may also affect consumption of electricity over time. Therefore, the measured consumption is not the same as the demand in the system. The difference between the two is often considered as the suppressed demand in the system. A full-scale analysis of the suppressed demand was not conducted for the current version of the IPSMP demand forecasts.

5.4. Generating Resources

As discussed in the previous chapter, there are three general types of generating units modelled in *GH-IPM 2023:*

- "Existing": Units that are operational in the Ghana electric industry, as of 31st December 2022.
- "Firmly planned": Units that are not currently operating but for which firm decisions have been made—thereby making them firmly anticipated to be operational in the future.
- "Potential": New generating technology options used in IPM for capacity expansion; i.e., units that could potentially be installed in the future.

Existing and firmly planned units are entered as exogenous inputs to the model, whereas potential units are endogenous to the model in the sense that the model determines the location and size of all the potential units that end up in the least-cost optimised solution for a specific set of model assumptions.

5.4.1. Existing and Firmly Planned Capacity

Currently, Ghana's existing capacity consists of a diversified mix of hydro, thermal, and renewable energy plants. A list of current operating power plants is shown in Table 17. The table shows the total number of generation units at each plant, as well as installed capacity, the net dependable capacity (which is used for the modelling), and the contribution of the plants to the reserve margin. The net dependable capacity is the expected capacity that is available for generation from a planning perspective, although on an operational basis, the amount up to the installed capacity (or greater) can be available for a short duration. The reserve margin capacity is the capacity that is available for meeting the peak demand. In most cases, the dependable capacity is the same as the reserve margin, except for non-dispatchable renewables and plants that are not controlled by the grid operator.

For example, the Genser power plants, which are captive power plants, can meet energy demand of their associated mines; however, these Genser plants are not expected to contribute to the reserve margin, as GRIDCo does not have the ability to call on them during peak hours.

Table 18 shows the firmly planned, under-construction power plants in Ghana, as of December 2022. Some of these power plants are expected to come in the first quarter of 2023 and in 2027, although their specific commissioning dates may vary.

Table 19 shows the operational and cost characteristics of the existing and under-construction power plants. The effective forced outages rate (EFOR) accounts for the planned outages for maintenance for these power plants, as well as the historical availability and outages. The firm retirement dates for some of the power plants are based on contractual obligations or expected firm retirements of power plants based on their lifetime. As noted in the previous chapter, this implementation of the *GH-IPM* does not make use of the model's ability to make economic retirement decisions. As such, all plants that do not have firm retirement dates are available to meet energy and peak demand needs throughout the modelling period. Table 16 is a list of the specific power plants with their respective online and firm retirement dates in the model:

Table 16: Contractual Firm Power Plant Retirement Dates in *GH-IPM 2023*

Plant Name	Online Date	Firm Retirement Date
CENIT	03/10/2013	10/03/2033
BXC Solar	15/01/2016	15/07/2036
Karpower Ship	01/01/2018	01/08/2037

The fixed operating and maintenance (FOM), the variable operating and maintenance (VOM) components of cost, and the heat rates of the power plants were estimated by the PPTC. FOM is the annual cost of maintaining a generating unit. It represents expenses incurred regardless of the extent that the unit is run. It is expressed in units of $ per kW per year. VOM represents the non-fuel costs incurred in running an electric generating unit. It is proportional to the electrical energy produced and is expressed in units of $ per MWh.

The information in Tables 16-21 will be updated over time, based on new information, as part of the IPSMP updates.

The existing BXC and MeinEnergy solar plants were procured on a feed-in-tariffs (FIT) basis, and the estimated cost of the FIT for this plant is shown as fixed costs in $kw-year. Similarly, the two VRA solar plants are also shown with a FIT expressed in fixed costs.

Table 17: Existing Power Plants in Ghana, as of December 2022

Plant Name	Online Date	Region	No. of Units	Operating Utility	Capacity Sub-Type	Installed Capacity (MW)	Net Dependable Capacity (MW)	Reserve Margin Contribution (MW)
Akosombo	Jan-1966	Akosombo, Eastern	6	Volta River Authority	Hydro: Hydro (Utility)	1020	900	900
Kpong	Jan-1982	Kpong, Eastern	4	Volta River Authority	Hydro: Hydro (Utility)	160	140	140
TAPCO (T1)	Mar-1998	Takoradi, Western	3	Volta River Authority	LCO/Gas Combined Cycle	330	315	315
TICO (T2)	Jun-2000	Takoradi, Western	3	Volta River Authority	LCO/Gas Combined Cycle	340	320	320
T3[17]		Takoradi, Western	5	Volta River Authority	LCO/Gas Combined Cycle	132	0	0
TT1PP	Jun-2009	Tema, Greater Accra	1	Volta River Authority	LCO/Gas Combustion	110	100	100
TT2PP	Jun-2010	Tema, Greater Accra	8	Volta River Authority	Gas Combustion Turbine	80	70	70
SAPP 1	Sep-2011	Tema, Greater Accra	6	Volta River Authority	Gas Combustion Turbine	200	180	180
VRA Solar Navrongo	Jan-2013	Navrongo, Upper East	1	Volta River Authority	Solar Photovoltaic	2.5	1.8	0
VRA Solar Kaleo	Dec-2021	Kaleo	1	Volta River Authority	Solar Photovoltaic	13	13	0

[17] T3 is currently offline, however, it is scheduled to come online in 2024 after which it's dependable and its contribution to peak will be 120 MW.

Plant Name	Online Date	Region	No. of Units	Operating Utility	Capacity Sub-Type	Installed Capacity (MW)	Net Dependable Capacity (MW)	Reserve Margin Contribution (MW)
		Upper West						
VRA Solar Lawra	Dec-2020	Kaleo Upper West	1	Volta River Authority	Solar Photovoltaic	6.5	6.5	0
Bui	Jun-2013	Bui, Brong Ahafo	3	Bui Power Authority	Hydro: Hydro (Utility)	404	333.5	333.5
CENIT	Oct-2013	Tema, Greater Accra	1	Cenit Energy Limited	LCO Combustion	110	100	100
KTPP	Oct-2015	Tema, Greater Accra	2	Volta River Authority	DFO/Gas Combustion	220	200	200
KarpowerShip	Sep-2019	Takoradi, Western	26	Karpower Ghana Ltd	HFO/Gas Combined Cycle	470	450	450
BXC Solar	Jan-2016	Winneba, Central	1	BXC Company	Solar Photovoltaic	20	18	0
Bui Solar	April-2021	Bui, Bono	1	Bui Power Authority	Solar Photovoltaic	50	45	0
Safisana	Sep-2016	Ashaiman, Greater Accra	1	Safisana Company Ltd	MSW – Landfill Gas	0.1	0.1	0
AKSA	Aug-2017; Jan-2019	Tema, Greater Accra	22	AKSA Energy Ghana	HFO/Gas Combined Cycle	370	330	330
SAPP 2	Mar-2017	Tema, Greater Accra	4	Sunon Asogli Power Co.	LCO/Gas Combined Cycle	360	350	350

Plant Name	Online Date	Region	No. of Units	Operating Utility	Capacity Sub-Type	Installed Capacity (MW)	Net Dependable Capacity (MW)	Reserve Margin Contribution (MW)
Cenpower	Jun-2019	Tema, Greater Accra	3	Cenpower Generation Company	LCO/Gas Combined Cycle	360	340	340
Twin City (Amandi)	Oct-2019	Takoradi, Western	3	AMANDI Energy	LCO/Gas Combined Cycle	210	201	201
MeinEnergy Solar Plant	Sep-2018	Winneba, Central	1	Meinergy	Solar Photovoltaic	20	18	18
Total			101			4,988.1	4,386.9	4,347.5

Source: Energy Commission, PPTC.

Table 18: Under-Construction Power Plants in Ghana[18]

Plant Name*	Online Date**	Region	No. of Units	Operating Utility	Capacity Sub-Type	Installed Capacity (MW)	Net Dependable Capacity (MW)	Reserve Margin Contribution (MW)
Ameri (6 Units)**	2023	Kumasi, Ashanti	6	Volta River Authority	LCO/Gas Combustion	150	135	135
Ameri (4 Units)**	2026	Kumasi, Ashanti	4	Volta River Authority	LCO/Gas Combustion	100	90	90
Early Power 1	Mar-2023	Tema, Greater Accra	6	Early Power	LPG/Gas Combustion	191	185	185
Early Power 2	Mar-2027	Tema, Greater Accra	3	Early Power	LPG/Gas Combustion	315	300	300
Total			19			756	715	715

Source: Energy Commission, PPTC.

* The online dates of these plants are tentative, as online dates are subject to change. The dates shown here are the expected dates of commissioning, as of December 2022.

**Ameri currently is a 250 MW existing power plant in Takoradi but 6 units out of 10 units is being relocated to Kumasi. The remaining 4 units will be used to revive T3. Per VRA's plan, in 2026, 4 units (Ameri 4 units) will be purchased and added to the 6 units (Ameri 6 Units) in Kumasi to make a total of 10 units (250 MW).

[18] Ghana Power Generation Company (GPGC) power plant was not considered in the assumptions because of uncertainty of construction.

Table 19: Operational Characteristics of Existing and Under-Construction Power Plants

Plant Name	IPM Ghana Zone	Net Dependable Capacity (MW)	EFOR	Firm Retirement	Heat Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Akosombo	SouthEastGH	900	3%		-	9.16	0.98
Kpong	SouthEastGH	140	2%		-	9.16	0.98
TAPCO (T1)	SouthWestGH	315	15%		8,462	18.7	6.9
TICO (T2)	SouthWestGH	320	15%		7,903	30.94	4.9
TT1PP	SouthEastGH	100	8%		11,335	14.3	6.5
TT2PP	SouthEastGH	70	8%		11,800	11.8;12.41	4.5
SAPP 1	SouthEastGH	180	15%		9,465	160	4.5
VRA Solar Navrongo	NorthGH	1.8	0%		-	255.67	0
VRA Solar Kaleo	NorthGH	13	5%		-	255.67	0
VRA Solar Lawra	NorthGH	6.5	5%		-	255.67	0
Bui	NorthGH	333.5	10%		-	31.46	1.63
CENIT	SouthEastGH	100	10%	Mar-2026	11,683	110.41	3.5
KTPP	SouthEastGH	200	8%		11,635	12.3	3.5
BXC Solar*	SouthWestGH	18	5%	Jul-2036	-	214.99	0
Bui Solar	NorthGH	50	5%			214.99	0
Safisana	SouthEastGH	0.1	15%		13,500	35.0	4.2
AKSA	SouthEastGH	350	10%	Nov-2023	8,630	62.36	21.7
SAPP 2	SouthEastGH	370	10%		7,825	98.35	11.2
Cenpower	SouthEastGH	340	10%		7,850	117.66	1.60

Plant Name	IPM Ghana Zone	Net Dependable Capacity (MW)	EFOR	Firm Retirement	Heat Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Karpowership	SouthWestGH	450	10%	Aug-2037	8,478	178.91	9.10
Amandi	SouthWestGH	190	10%		7,775	193.42	7.9
Early Power 1	SouthEastGH	185	7%		7,500	19.7	3.23
Early Power 2	SouthEastGH	300	7%		7,500	19.7	3.23
Ameri (with VRA)	AshantiGH	230	10%		11,279	14.54	4.17
Mein Energy*	SouthWestGH	18	5%	Sep-2038	-	214.99	0
VRA Solar_kfW*	NorthGh	17	5%		-	255.67	0

Source: Energy Commission, PPTC.

*These numbers are based on FiT and expected energy output

Table 20: Annual Capacity Factor Constraints for Selected Power Plants

	Maximum Capacity Factor		
	Akosombo	Kpong	Bui
2023	73.4	83.0	30.8
2024	69.7	80.5	30.8
2025	62.0	75.0	30.8
↓	↓	↓	↓
2040	51.1	72.2	30.8

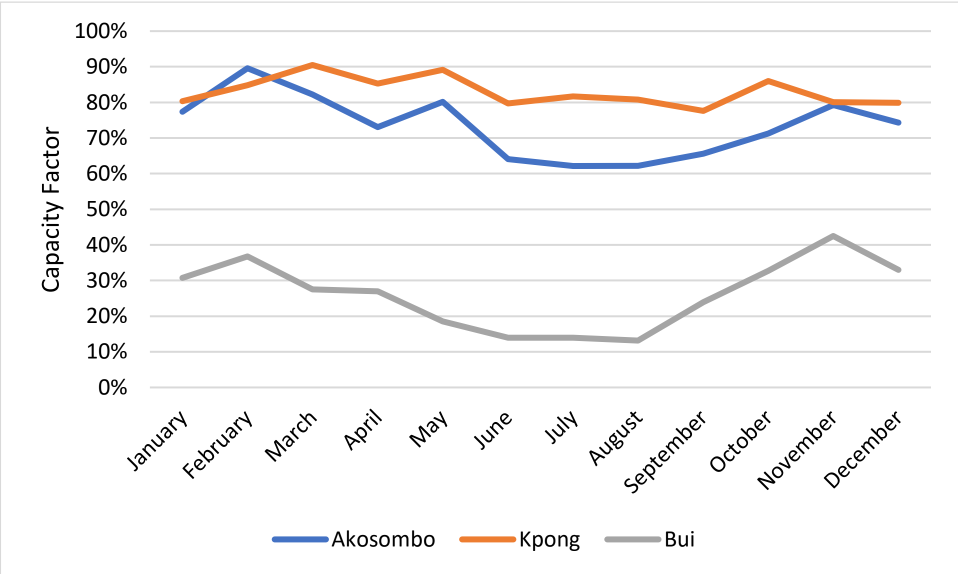


Figure 19: Monthly Pattern for Hydropower Generation

Source: VRA and BPA.

A number of operational and contractual constraints require the generation of electricity from particular power plants. The operational constraints for the hydropower plants in terms of their annual capacity factors, as well as the seasonal availability factors, are shown in Figure 19 and Table 20.

The Akosombo hydropower plant has a very strong influence on the Ghana power system, given that it is the largest power plant in the country and it provides the necessary ancillary services (e.g., voltage and volt-ampere reactor support, reserve margin during peak demand periods) for the operation of the Ghana Nationally Interconnected Transmission System (NITS). As such, a minimum of about two turbines (270 MW) of Akosombo and one turbine of Kpong (42 MW) must always be operating in order to support the grid. As such, this minimum capacity is forced to run at all times in the model, using the IPM's "area protection" feature.

Another key long-term future constraint (2026–2040) for the Akosombo and Kpong power plants is the need to build up the amount of water in the reservoir in order for the hydropower plants to continue to operate at their long-term average output of 5,300 GWh per year (for both plants combined). In order to ensure this buildup of water in the reservoir, the annual capacity factors for these two plants reduces from 2023, eventually reaching 62% for Akosombo and 75% for Kpong by 2025. From 2026 to 2040, the capacity factors are fixed at the long-term average. See Table 20.

Finally, given the reliance of the Ghana power system on the hydropower plants, it is important to assess the implications of reduced or limited inflows into the existing dams. A recent report published by the Council for Scientific and Industrial Research (CSIR) indicated that inflows into the reservoir for the hydropower systems could be reduced by about 30% in the long run due to climate change (IWMI, 2012). Therefore, in one of the possible sensitivity cases that assesses the implication of reduced inflows due to climate change, the annual capacity factors for hydropower generation from Akosombo and Kpong were reduced from their respective long-term average in 2026 to a value that is reduced by 32% in 2040; a similar 25% reduction was made for Bui. A linear decrease in capacity factors was assumed from 2023 to 2040 for this sensitivity.

5.4.2. **Cost and Performance of New Generation Options**

Ghana's power system currently has the potential to use a number of new technologies for power generation, in addition to those currently in place. Furthermore, the performance of the existing suite of technologies is improving such that power can be generated more efficiently. The cost of renewable energy and storage technologies is decreasing quite dramatically across the globe and it is important to account for this significant trend.

The efficiency and cost trends for new power generation technologies were based on publicly available information, and are shown in Table 21.

The total installed cost of developing and building a new plant is captured through the overnight capital cost. They include engineering, procurement, construction, startup, and owner's costs (for such items as land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, etc.). Interest during construction (IDC) is added to the capital costs, as shown in Table 21 because different types of power plants have different construction times. Calculation of IDC is based on the construction profile and the interest rate, which is assumed to be 5% per year for all of the power plants, except for a nuclear plant, which is assumed to have an IDC of 3% per year.

In addition, the costs of solar PV and wind power plants are expected to decline over time, and as such, they have specific vintage years associated with them. Vintage periods are used to capture the cost and performance improvements resulting from technological advancement and learning-by-doing. Mature technologies including coal and nuclear, do not have a declining cost trend, and so their costs in real 2016 dollars remain the same throughout the modelling period.

5.4.1. **Capital Cost Sensitivity**

The capital cost assumptions shown in Table 21 could vary depending on various factors: technological improvements, global price changes, risk perception as expressed by the discount factor, etc. Ghana is generally a price taker with respect to the cost of these new technologies because the equipment required for them is mostly imported, and as such, it cannot fully control their cost. On the other hand, the country can reduce financing costs of these technologies by addressing the current financial challenges in the sector, and diligently enforcing the use of competitive bidding for power procurement.

Table 21: Cost and Performance of Potential Power Plant Technologies for Ghana

Technology Type	Years of Const.	Overnight Costs w/o IDC[1]	Capital Cost w/ IDC[2]	Fixed O&M[3]	Variable O&M[3]	Heat Rate[3]
		2016$/kW	2016$/kW	2016$/kW-yr	2016$/MWh	Btu/kWh
Biogas	1	4000	4200	410.3	5.5	18,000
Biomass	2	3720	4000	130.0	4.5	13,500
Natural gas – CCGT	2	968	1041	15.0	3.6	7,250
Natural gas – OCGT	2	902	947	11.5	4.2	10,000
Hydro – small	4	4500	5000	45.0	3.0	
Solar PV – 2023	1	560	560	24.8		
Solar PV – 2026	1	523	523	24.8		
Solar PV – 2035	1	445	445	24.8		
Onshore wind – 2020	2	1437	1547	46.7		
Onshore wind – 2026	2	703	757	46.7		
Onshore wind – 2035	2	648	697	46.7		
Coal	4	2788	3154	65.0	6.0	8,800
Nuclear	7	5700	6233	100.0	2.3	10,300

Notes:

1. The overnight costs were developed from an average of costs taken from EIA 2021, IEA 2021, and Lazard 2017.
2. Overnight cost of Solar and Wind for 2023 and beyond were developed based on expected future nominal tariffs of 8.5 US cents and 9 US cents, respectively (assuming a flat rate in nominal dollars over the PPA period)
3. Heat rate, fixed O&M, and variable O&M were estimated based on EIA 2016.

From a planning perspective, it is important to consider sensitivities around the capital costs of the different technologies, particularly those for renewable energy. Accordingly, high and low capital cost sensitivities were estimated for various technologies based on available research such as Lazard, U.S. Energy Information Administration (EIA), IEA, and Bloomberg New Energy Finance, among others.

Given that most of these studies and research reports point to a continued decline in the capital cost of solar PV projects or systems, the reference capital cost for 2023 and 2020 was maintained as the High Case for the 2023–20340 periods, respectively. Table 22 shows the various sensitivities considered for renewable energy technologies.

Although conventional thermal technologies are mature, and it is very unlikely costs would decrease significantly, a potential sensitivity where capital costs of these technologies were decreased was also considered (e.g., if these technologies were provided to Ghana at a low cost to support the development of these technologies). In this sensitivity, it was assumed that the cost of combined cycle plants could drop by 40%, combustion turbines by 20%, coal plants by 10%, and nuclear plants by 20%.[19]

---

[19] It is important to point out that this sensitivity is contrary to current trends where coal and nuclear power plant costs are expected to increase in the future due to more stringent regulatory measures and increased cost materials for building such power plants. As shown by Lazard, over the past few years

Table 22: Capital Cost Sensitivities for Various Renewable Energy Technologies

Solar PV

Online Year	Unit	Reference	High Cost	Low Cost
2023	USD/kW	560	751	368
2026	USD/kW	523	702	344
2035	USD/kW	445	597	293

Solar PV with Storage

Online Year	Unit	Reference	High Cost	Low Cost
2026	USD/kW	731	981	481
2035	USD/kW	632	848	416

Wind

Online Year	Unit	Reference	High Cost	Low Cost
2020	USD/kW	1,547	1,856	1,238
2026	USD/kW	757	1,049	465
2035	USD/kW	697	965	428

5.5. POWER SYSTEM OPERATIONS ASSUMPTIONS

5.5.1. Capacity, Generation, and Dispatch

While the capacity of existing and firmly planned units is an exogenous input into the IPM, the dispatch of those units is an endogenous decision that the model makes, as discussed in the previous chapter. IPM determines the optimal economic dispatch profile of any given unit based on the operating and physical constraints imposed on the unit. In *GH-IPM 2023,* unit-specific operational and physical constraints are generally represented through availability and area protection constraints. However, for some unit types, capacity factors are used to capture the resource or contractual constraints on generation. The two cases are discussed below.

Availability

Power plant “availability” is the percentage of time that a generating unit is available to provide electricity to the grid. Availability considers both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit’s available hours adjusted for derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. The *GH-IPM 2023* used IPM’s effective forced outage rate (EFOR) function in specifying availability of the units. Table 19 shows the EFOR assumed for each power plant.

Capacity Factor

Generation from certain types of units is constrained by resource limitations. These technologies include hydro, wind, and solar. For such technologies, IPM uses capacity factors

---

the capital cost of nuclear and coal power plants has been increasing. Moreover, increasing efficiency and performance of these power plants would also increase the capital costs generally (on $/kW basis).

or generation profiles to determine the maximum possible generation from the unit. For example, a photovoltaic solar unit would have a capacity factor of 17% if the usable sunlight were only available that percent of the time over the entire year. For such units, explicit capacity factors or generation profiles mimic resource availability. For hydropower plants, capacity factors constrain the total volume of generation by month and by year.

Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the percent of total dependable capacity that is above the annual system peak load. The additional capacity beyond the annual peak demand is to meet unforeseen contingencies and forced outages of power plants.

The reserve margin percentage is often dependent on the total number of units and the size of the largest generating unit in the power system under consideration. Smaller power systems with limited number of units need to have larger reserve margins in percentage terms than bigger power systems with more units.

Reserve margins are often calculated based on studies that assess the joint probabilities of outages in generation or transmission units in the system. However, for the Ghana IPM model, we considered a simpler analysis. An assessment of the impact of the loss of two critical generating units or plants in Ghana was done. The assumption was on the loss of an entire Karpower plant which can go out due to transmission or fuel challenges and the loss of one or more generating units (each rated at 150 MW of net dependable capacity) of the Akosombo and Kpong hydro plant. The cumulative capacity of 450 MW (Karpower),170MW and 35 MW(a unit of dependable capacity of Akosombo and Kpong respectively) was used to determine the planning reserve margin. This translates to about 18% of the 2023 projected peak of 3,668MW. The specific reserve margins used in the *GH-IPM 2023* are shown in Table 23.

Unlike what has been usually done by the various planning agencies so far (e.g., GRIDCo, ECG, EC), reserve margin assumptions in Table 23 are separately enforced for each model zone, rather than for Ghana as a whole. For example, the NorthGH Zone has to meet the planned reserve margin requirements for every year (e.g., 17% in 2023) on its own, through firm transmission or new plants in the NorthGH Zone. Similarly, for each of the four Ghana zones. Therefore, the reserve margin requirement in the *GH-IPM 2023* model is stronger than if it was enforced for all of Ghana, without considering transmission constraints.

Table 23: Reserve Margin Assumptions for each of the four GH Zones

Year	Annual RM
2023	18%
2024	18%
2025	18%
2026	18%
2027	18%
2028	18%
2029	18%
2030	18%
↓	↓
2040	18%

The contribution of the various power plants to the reserve margin is shown in Table 17 and Table 18, and this is often the dependable capacity for existing thermal or hydro units or the capacity build by IPM for new conventional, dispatchable units. The reserve margin capacity contributions for renewable units are described in Section 5.6.

Power Plant Lifetimes

The *GH-IPM 2023* version does not include any pre-specified assumptions about power plant lifetimes except for some contracted power plants with defined decommissioning dates. Retrofits and economic retirements were not included in the *GH-IPM 2023* but will be considered in the next update.

Heat Rates

Heat rates, expressed in BTUs per kWh, are a metric of the efficiency of a generating unit. It was assumed that heat rates of existing units would remain constant over time. This assumption reflects two offsetting factors: (1) plant efficiencies tend to degrade over time and (2) increased maintenance and component replacement work to maintain or improve plant efficiency. It is important to recognise that in the current version, the cost of maintaining the heat rates through O&M investments is not included. However, they can be included in a future version that also assesses economic retirements.

The heat rates for existing power plants in the *GH-IPM 2023* are based on data collated from VRA, PURC, and ECG. Heat Rates for the existing and potential build power plants can be found in Table 19 and Table 21, respectively.

5.6. RENEWABLE ENERGY RESOURCES

5.6.1. Wind Generation

Wind Resource Potential: This version of the Ghana Model, *GH-IPM 2023*, includes only onshore wind generation as a potential source of energy, which is limited to only the SouthEastGH zone. This is because of the relatively better and more economical wind regime (See Figure 20) in the SouthEastGH zone, and also particularly because of the availability of ground-measured data. However, future updates could include other zones.

Potential wind capacity is constrained in the *GH-IPM 2023 to* reflect the resource availability and the potential operational constraints that are inherent with variable renewable energy resources. As shown in Table 24, the maximum wind capacity limit used in the *GH-IPM 2023* is 700MW, although there is potential for more[20] it will require more detailed study to identify specific capacity limits per model region to inform the redefinition of limits in the model.

[20] IRENA, Ghana Renewables Readiness Assessment, 2015. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/IRENA_RRA_Ghana_Nov_2015.pdf

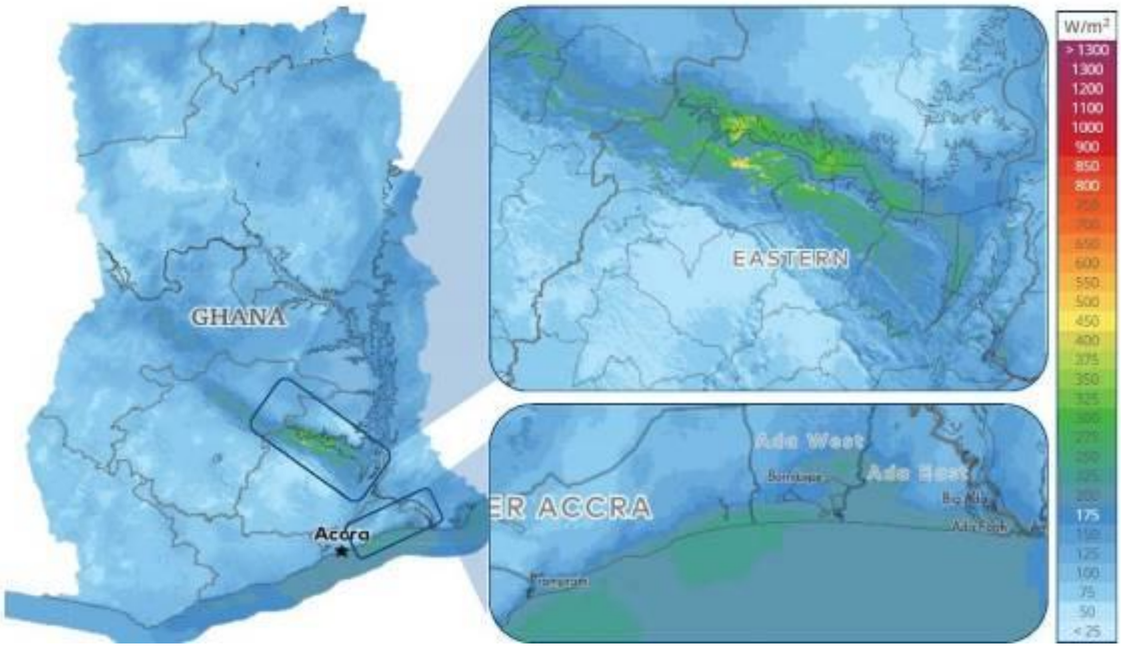


Figure 20: Wind Resource Map – Ghana

Source: https://www.globalwindatlas.info (last accessed July 30, 2018).

Table 24: Reference Wind Capacity Limit in the GH-IPM 2023v1

	IPM Model Zone	Maximum Capacity (MW)
Reference Case	SouthEastGH	700

Generation Profile: Wind and solar are only dispatched when the sun shines and the wind blows, hence these resources use generation profiles included in the model. Historical hourly wind resource data from the Energy Commission were used to create a typical hourly generation pattern of a typical day in a particular month for the SouthWestGH zone. See Figure 21. For Hour 1 through Hour 24, the generation profile indicates the amount of generation (kWh) per MW of available capacity in that month.

Reserve Margin Contribution: Each zone in the model has a reserve margin, which represents the amount needed to maintain reliability in the zone. The ability of a unit to contribute the net dependable capacity in its zone (or to contribute to another zone through firm transmission) is modelled through the unit's contribution to reserve margin. Due to the intermittent nature of wind and the hours it is available relative to the peak demand hours in Ghana, it does not fully contribute to the reserve margin. In the *Ghana-IPM 2023*, wind is expected to contribute about 20% of its installed capacity to the reserve margin. This was estimated from resource availability during the peak hours.

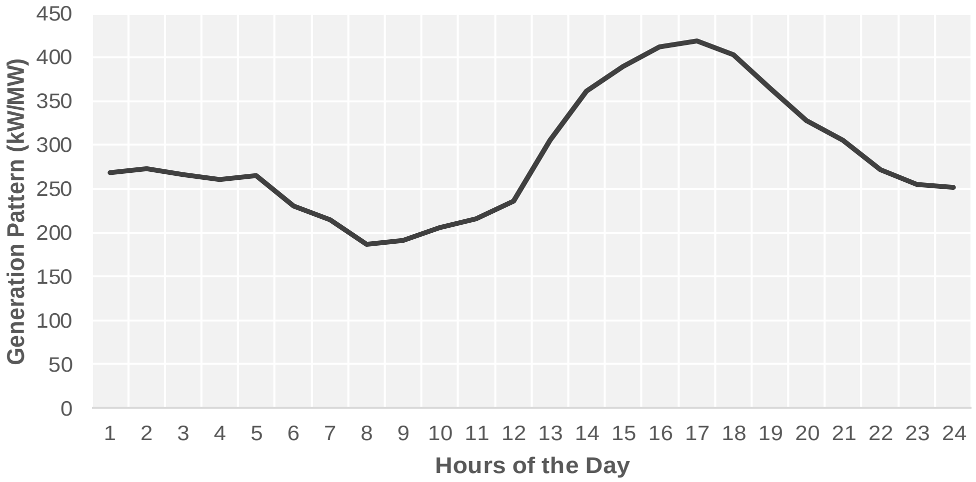


Figure 21: Typical Wind Generation Profile used in the GH-IPM2023 v1.[21]

5.6.2. Solar Generation

Solar Resource Potential: The resource potential estimated for solar PV and solar PV with storage was developed from some existing photovoltaic plants operating in the country and resource maps. Due to the ubiquitous nature of this resource in the country, solar PV is made available in all four model zones; although with varying potentials due to potential grid interconnection challenges in the zone. The nature of incident irradiance in the country does not lend itself to the economic use of concentrated solar technology, and therefore, this option was not included in the model.

Similar to the wind, the maximum possible solar photovoltaic capacity is limited in the various zones, mainly due to operational and interconnection constraints. The limits in the reference assumptions are indicated in Table 25.

These limits are, however, nearly doubled in the high resource case for some strategies (e.g., the Indigenous Resources and the Enhanced G-NDC, see Chapter 7). A detailed study of specific limits for the various zones is needed to further fine-tune these constraints in the model. Below is a summary table of the capacity limits for Solar PV and Solar PV with Storage in the *GH-IPM 2023*.

Table 25: Reference Solar Photovoltaic Capacity Limit in the GH-IPM 2023v1

	IPM Model Zone	Maximum Capacity (MW)
Solar PV	AshantiGH	217.5
	NorthGH	1440
	SouthEastGH	960
	SouthWestGH	845
Solar PV with Storage	AshantiGH	117.5
	NorthGH	585
	SouthEastGH	640
	SouthWestGH	375

[21] Illustrative hourly wind profile (kW of generation per MW of electricity). The complete data set can be found in the Assumptions Sheet attached in Volume 3.

Generation Profile: Like wind, solar PV is an intermittent renewable technology and can only be dispatched when the sun shines. On an economic basis, solar and wind plants have zero or near-zero operational costs, such that they would be dispatched whenever it is available. The generation profiles for solar PV specify the hourly generation patterns for typical days in each eligible zone for each month. The generation profiles were prepared with data from existing solar generation units and adjusted for the different model zones. Figure 22 shows a typical profile for both solar PV and solar PV with storage.

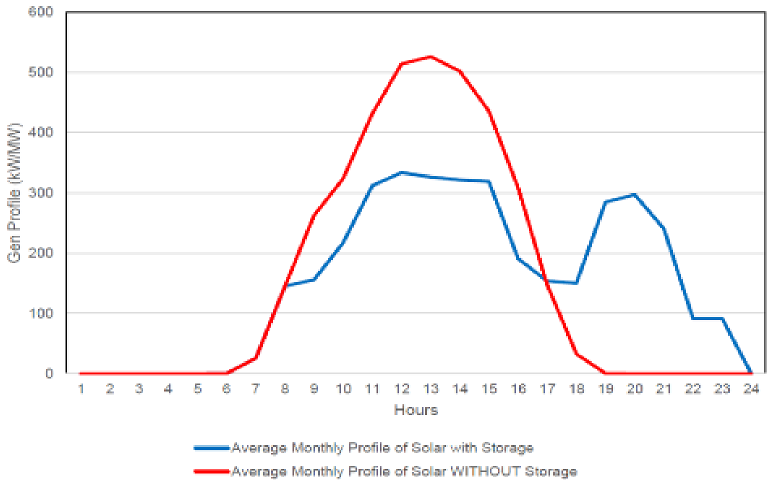


Figure 22: Typical Hourly Solar Generation Profile in IPM

Reserve Margin Contribution: Only solar PV with storage contributes to the reserve margin because the solar PV power output does not coincide with the peak demand. However, the solar with storage option makes about 30% contribution to reserve margin due to the availability of the storage during the peak demand period. Solar's contribution to peak demand, if there is storage, is shown above.

5.6.3. Dispatchable Renewables

The dispatchable renewable technologies available in the GH-IPM 2023 version are biomass (combustion and gasification) and biogas. These technologies were made available in all four regions given the ubiquitous nature of these resources in Ghana. Biomass is offered as a fuel for potential (new) biomass direct-fired boilers and biogas plants (waste to energy), and they contribute 100% to the reserve margin. Table 26 and Table 27 show the biomass capacity and availability constraints included in the model.

Table 26: Reference Biomass Capacity Limits in the GH-IPM 2023

	IPM Model Zone	Maximum Capacity (MW)
Biomass	AshantiGH	55
	NorthGH	0
	SouthEastGH	80
	SouthWestGH	45
Biogas	AshantiGH	21
	NorthGH	43
	SouthEastGH	32
	SouthWestGH	27

5.6.4. Renewable Energy Penetration Target Option

The Ghana IPM model does have the option of building new renewable energy capacity to meet renewable energy penetration targets if they are called for by policy. However, modelling of the 2023 version of the Ghana IPM does not include such RE targets in the uncontrained strategy; instead, only the economics dictates the building of new renewable technologies.

5.6.5. Renewables-based Mini-Grids

Renew able energy-based minigrids are now becoming an important option for increasing electricity access in remote and lakeside communities. Currently, VRA operates five mini grids in Lakeside communities which were built by the Ministry of Energy. Funding has also been secured by the Ministry to build additional 35 minigrids on island communities on the Volta lake.

5.7. Fuel Supply and Price

5.7.1. Oil Prices and Availability

Although most existing power plants in Ghana are dual fuel plants, they have had to rely heavily on fuel oils for power generation historically, due to the inconsistent/unreliable supply of natural gas. For instance, plants such as Karpowership, AKSA, and TAPCO switch from natural gas to their respective secondary fuel (HFO, LCO) on an as-needed basis, that is, when there is curtailment of gas supply. These fuel oils were therefore an important part of the fuel supply options in the model.

Table 27: Biomass Availability Constraint in the *GH-IPM 2023*

Year	Volume (MMBtu)
2023	10,355,261
2024	10,413,984
2025	16,974,088
2026	17,034,641
2027	17,096,131
2028	17,158,572
2029	17,221,981
2030	17,286,372
2031	17,351,761
2032	17,418,165
2033	17,485,598
2034	17,554,079
2035	17,623,623
2036	17,694,247
2037	17,765,970
2038	17,837,167
2039	17,908,649
2040	17,980,418

Procurement of these liquid fuels is done by VRA and independent power producers (IPPs) on the spot markets, considering the volume of available storage facilities that are located close to the power plants for operational purposes. Therefore, for the IPSMP modelling, the availability of liquid fuel supply is not constrained, and the model determines the use of liquid fuels for power generation, based on the price of other fuel options and other operational constraints in the system.

Oil and liquid fuel prices in the future are difficult to project, based on history. Therefore, for the IPSMP several different oil price projections from various international agencies were considered. For example, oil price forecasts from the U.S. EIA and the World Bank are shown in Figure 23, and these forecasts are based on different methodologies. Generally, the U.S. EIA reference oil prices tend to increase rather quickly over time due to an expectation of demand growth, whereas the World Bank forecasts tend to emphasise the availability of low-cost resources to keep price increases in check. For the IPSMP, an average of the two projections is used as the best-guess estimate of future oil prices (see Figure 23). The reference crude oil price forecasts were derived by taking an average of crude oil commodity price projections by the World Bank and the U.S. EIA. The World Bank forecasts were sourced from its April 2019 release of Commodities Price Forecasts; the U.S. EIA forecasts were sourced from its 2019 Annual Energy Outlook publication.

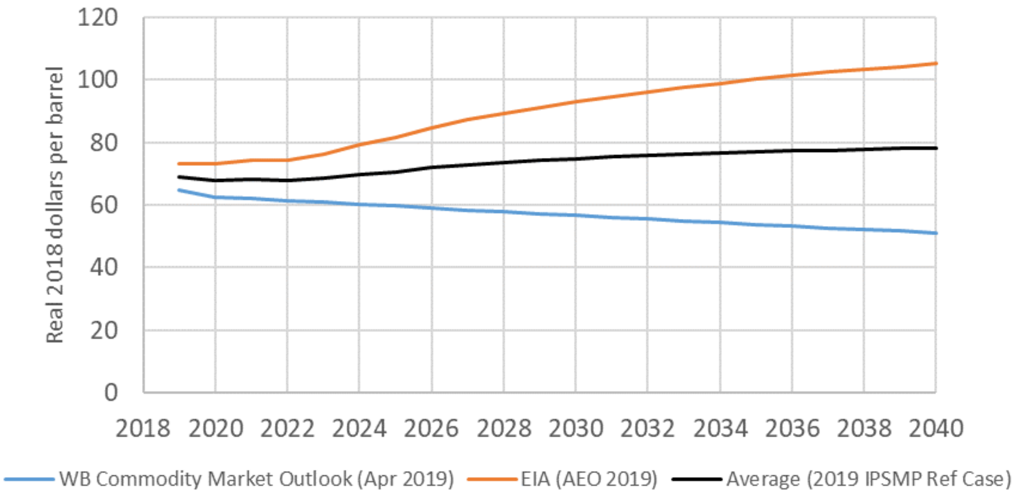


Figure 23: Crude Oil Price Forecasts ($/bbl) in 2016$

Liquid fuel prices (HFO, LPG, and DFO) and LNG prices are modelled as a percentage of the oil price.

LNG prices are assumed to be linked to crude oil prices, and they are not assumed to decouple from this oil link.

Given the uncertainty around oil price projections, it is important to consider potential sensitivities around oil prices. High and low oil price cases for the IPSMP sensitivities were developed based on percent increases (and decreases) of the high and low cases projected by U.S. EIA, relative to their Reference Case forecast. The resulting high and low case oil price projections for the IPSMP sensitivities are shown in Figure 24.

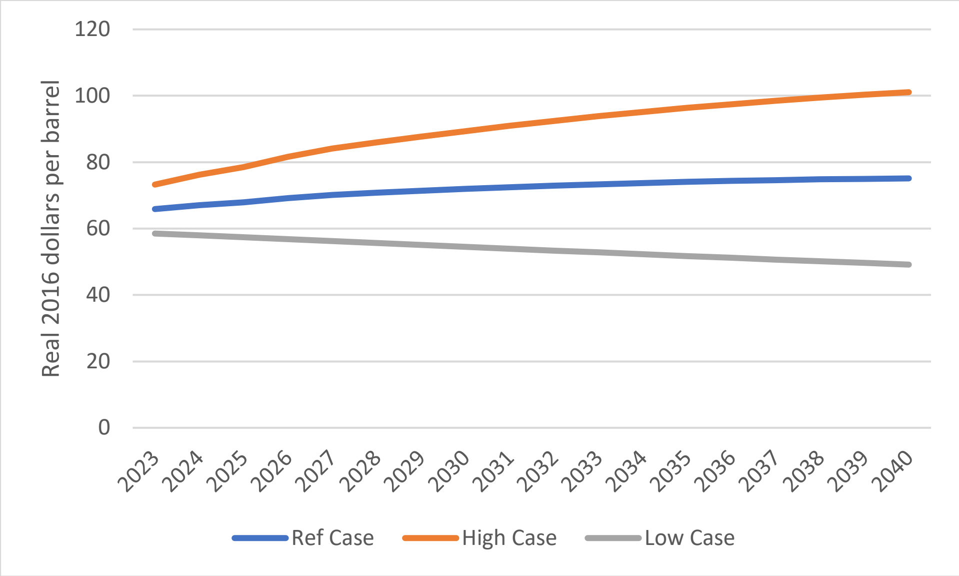


Figure 24: Crude Oil Price Sensitivities

5.7.2. Natural Gas

Since December 2014, there have been two primary supply options for natural gas for power generation in Ghana: Nigerian gas through the West African Gas Pipeline (WAGP) and indigenous gas that is produced and processed through the Atuabo Gas Processing Plant.

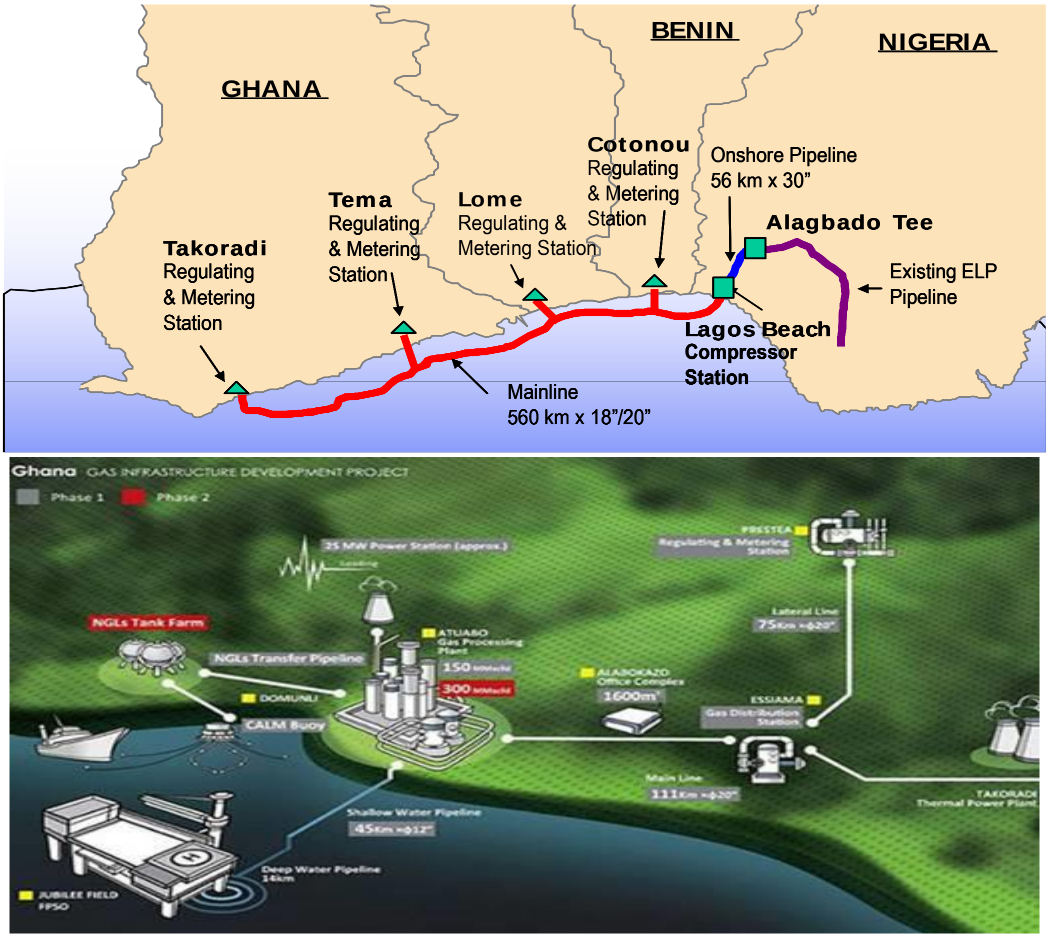


Figure 25: Existing Natural Gas Pipeline Infrastructure for Gas Supply in Ghana

Source: GNPC, WAGP.

The Nigerian gas is transported from the delta regions of Nigeria via Escravos Lagos Pipeline System to Ikeja in Lagos then through the WAGP to power plants in Tema and Aboadze. The indigenous gas (associated and non-associated) is produced, however, from offshore fields in Ghana. The associated gas from Jubilee and TEN is processed onshore at Atuabo, and then delivered to power plants in the Aboadze power enclave. The non-associated gas from the Sankofa field is produced and conditioned to pipeline specifications and delivered to the National Gas Transmission System at Sanzule, for transmission through the NGTS. Figure 25 shows the pipeline infrastructure associated with these two sources.

Consumption of gas for power generation in Ghana began in 2009 when Nigerian gas was supplied to Tema and Takoradi power plants through the WAGP (see Table 28). TAPCO and Sunon Asogli plant were the first plants to have utilised this new gas supply from Nigeria. This supply line was critical to power generation in the country given that Sunon Asogli was a gas-only plant.

However, a number of issues including supply interruption in 2011 to 2012 and gas supply issues in 2013–15, and payment issues in 2015–16 resulted in limited gas supply through the WAGP to power plants in Ghana. WAGP gas supply was effectively cut off for nearly half a year due to non-payment of bills to WAGPCo. WAGP gas was only restored towards the end of 2016, as WAGPCo and the Government of Ghana came to an agreement to address the debt issues.

At the same time, domestic gas supply from Jubilee fields was confronted with challenges with the turret and compressor of the floating production, storage offloading unit (FPSO) which resulted in interrupted supplies to TAPCO, TICO, and Ameri. Unlike in 2016, gas supply to Ghana power plants has been more stable since 2019, which allowed for more gas-fired generation in Tema and Takoradi.

Table 28: Annual Gas Supply Volumes (MMBtu)

Year	WAGP (Nigeria)	Indigenous Production
2013	11,573,000	
2014	22,541,000	2,040,000
2015	20,625,000	26,391,000
2016	4,003,000	23,473,000
2017	11,713,000	33,749,000
2018	26,036,130	39,072,672
2019	23,764,532	55,321,073
2020	24,440,681	95,166,167
2021	18,707,886	107,834,388
2022	20,236,447	268,768,215

Source: Energy Commission, 2023.

Natural gas has been playing, and is expected to play, an important role in Ghana's power sector, but it had gotten off to a poor start in terms of reliability. Ensuring reliable gas supply has become a key concern for power planners, and therefore there is significant interest in developing LNG imports and regasification infrastructure.

According to GNPC's "base-case" projections of indigenous gas production, Jubilee, TEN and Sankofa are expected to decline over time, unless additional development and production are undertaken in those fields. Figure 26 shows the expectations of indigenous gas supply, as per discussions with GNPC. These projections demonstrate that without any other new field development or extension of the production life of the existing fields, domestic gas production may cease in 2036.

It is also very important to recognise, and include in the modelling, the contractual obligations that affect the Sankofa gas production. The Government of Ghana, through the GNPC, has agreed to a 90% take-or-pay contract on gas volumes from Sankofa field production. This implies that 90% of Sankofa gas production must be consumed in Ghana, and without any other major gas use, this gas must be used in the power sector. Therefore, the IPSMP modelling has a minimum consumption of 90% from Sankofa production. Furthermore, production from Jubilee and TEN fields is modelled to be consumed by Ghana power plants.

Given the high production volumes expected from Sankofa and its 90% take-or-pay contractual obligation, the WAGP infrastructure was modified in June 2019, to allow for the domestic gas to flow from the Aboadze area to Tema, which is termed as the "reverse flow". Total capacity for the reverse flow is estimated at 225 mmcfd at the entry point in Takradi and 235MMscfd at the exit point in Tema. The availability of the reverse flow capacity does not imply the gas will flow from west to east, but only that this capacity is available to the model to utilise, if it happens to be a least-cost option.

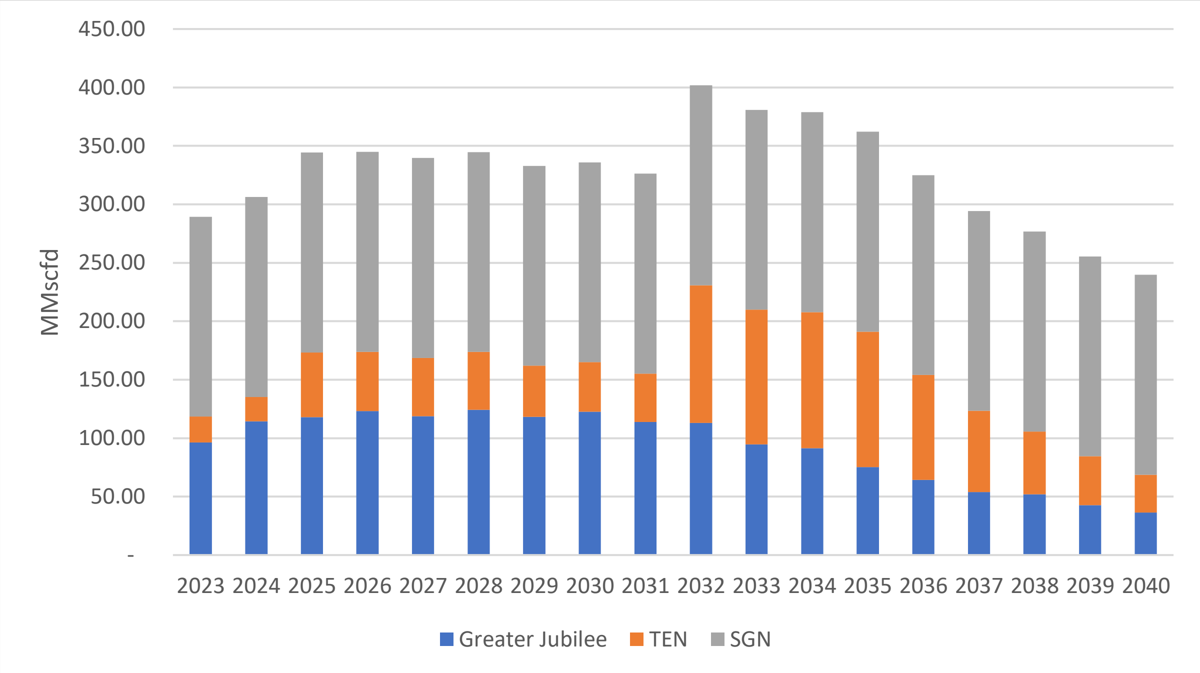


Figure 26: Average Daily Production Profile for Indigenous Gas – Reference Case

Source: GNPC(2023-2036), PPTC(2037-2040).

For modelling purposes, Nigerian gas through the WAGP was capped at about 120 million cubic feet per day (MMcfd) of gas supply to power plants in Tema, starting in 2023.

From discussions with GNPC, additional new field development and production are expected in the late 2020s hence this 2023 version of the Ghana IPM has included a new gas source which is a proxy for additional supply coming into production in 2028 and beyond. The maximum daily average capacity for this new source is about 500MMcfd. The gas is only available for utilisation if its economical to do so.

The IPSMP modelling also considers LNG as a potential resource to ensure gas supply reliability, particularly because GNPC has a contract with Shell for the supply of gas from the Tema LNG terminal.

The Tema facility is expected to have a maximum daily average capacity of about 400 MMcfd. GNPC and its counterparties have delayed the commencement of the project until the end of 2024.

Currently gas pipeline infrastructure is being constructed to Kumasi to serve the Middlebelt power enclave. Therefore, the model assumes that natural gas is available for use Kumasi/Middle Belt area, with an additional estimated transport cost of $1.65/MMBtu. This allows for the model to consider potential new-build gas power plants in the Middlebelt area (if it is cost-effective) in addition to Ameri and AKSA.

5.7.3. **Natural Gas Price**

The price of natural gas is a key variable that affects the utilisation of existing gas-based power plants and whether new gas power plants need to be built. The price of indigenous gas is dependent on a number of different factors, including the contractual terms agreed to between GNPC and the producers, and the cost of gas processing and transportation. The midstream and transportation costs are regulated by the Public Utilities Regulatory Commission (PURC).

The price of lean gas from both domestic and import sources for power generation is a weighted average delivered cost determined by the Public Utilities Regulatory Commission (PURC). The Weighted Average Cost of Gas (WACOG) for power generation in 2023 was US$6.1/MMBtu[22] and this price was used throughout the planning horizon. However, this can be updated anytime PURC revises its WACOG.

[22] https://www.purc.com.gh/attachment/705636-20230124100135.pdf

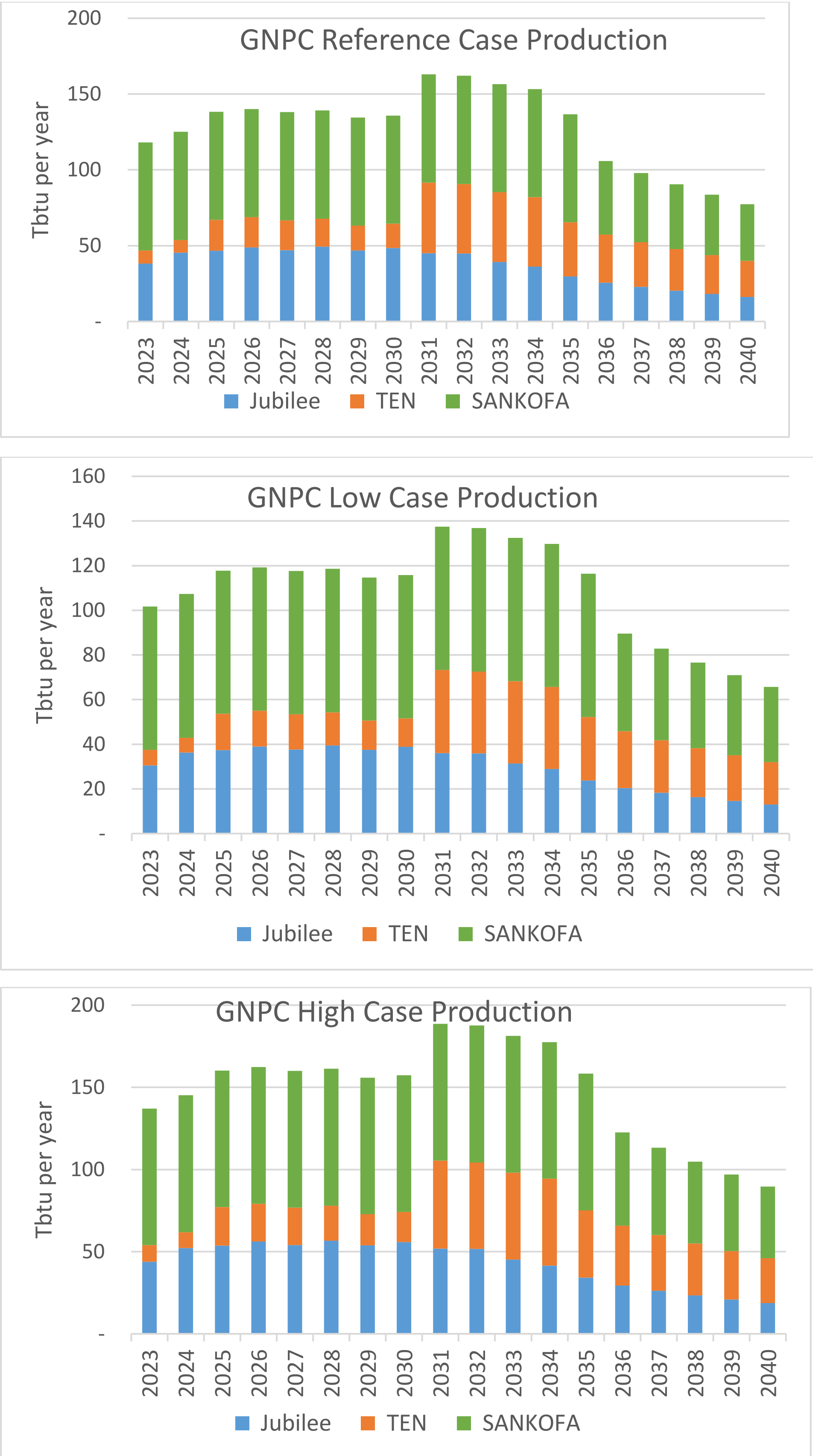


Figure 27: Sensitivity of Domestic Gas Production.

Source: GNPC

5.7.4. Natural Gas Volume and Price Sensitivities

The need for an accurate estimate of indigenous natural gas production in power sector planning cannot be overstated, as this is a key parameter in the determination of the need for capacity and timing of new power plants. A series of discussions were therefore held with GNPC in developing gas production projections for Sankofa, Jubilee, and TEN. As noted earlier, the IPSMP Reference Case production profile is an update of the reference projections in the GMP. The GMP also developed high and low case projections for gas production, the percent changes relative to the GMP Reference Case were used to develop the IPSMP high and low case scenarios. See Figure 27.

The LNG commodity prices are linked to oil prices, as discussed above, and the projected high and low prices for LNG are shown in Figure 28.

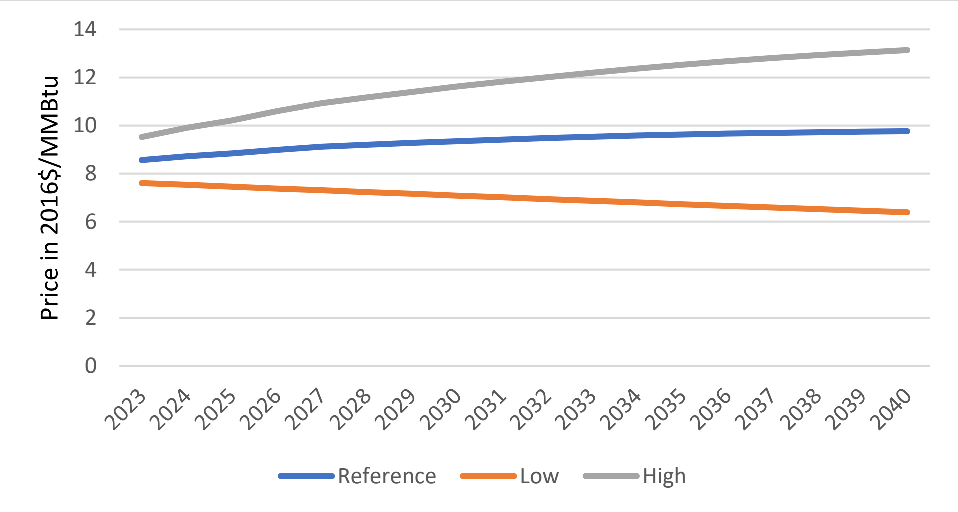


Figure 28: LNG Commodity Prices in 2016$/MMBtu

Source: PPTC

5.7.5. Nuclear Fuel Price

Given the nascent plans for nuclear power generation in Ghana, current expectations are that for the country's first and second nuclear power plants, the fuel for the entire lifetime will be procured as part of the contract to build the first and second nuclear reactors. Thereafter, a procurement strategy of nuclear fuels for power plants in the country could be built on the following elements: (i) diversification of suppliers and supply areas; (ii) long-term supply contracts through competitive bidding process; and (iii) possible participation in mining projects in other countries. Such a strategy will also have to conform with all international safety and safeguards standards for handling nuclear materials. Furthermore, storage of efficient inventory policy, which will ensure that sufficient levels of inventory of nuclear fuel are always available shall complement the nuclear fuel supply strategy.

In the current GH-IPM Version 2023 model, a cost of $1.28/MMBtu in constant 2016 dollars was included as nuclear fuel cost and handling throughout the modelling period. This cost will have to be updated in further discussions with the GNPPO.

5.8. TRANSMISSION

The Ghana modelling zones, discussed earlier, were based on the specific transmission constraints that are prevalent for the Ghana NITS. The total transfer capability (TTC) across the various zones on firm (under N-1 condition) and non-firm (N condition) bases determine the extent to which new power plants will need to be built in various zones to meet the required reserve margin and energy demand for each of the zones.

Figure 29 shows the schematic diagram of the transmission links/corridors between the zones, and Table 29 shows the updated firm and non-firm TTCs between various zones, based on transmission flow analysis that was conducted on Ghana's power system using the PSS/E model. The analysis was done for the short term (2023-2025) and for the long term (2026-2040). The line loadings criteria used for the study is based on the adequacy criteria in the grid code that states all line loadings under normal conditions (Nosn-Firm) should be 85% and 100% under contingencies (Firm).

The TTCs for the short term (2023-2025) considered planned transmission investment and generation additions for the period. The additions include Tafo Upgrade Project, Construction of a new 330kV substation at Prestea, installation of ±50 MVAr SVC's at 330 kV Nayagnia and the new 330 kV Prestea Substations and relocation of 250 MW Ameri to Kumasi. The planned transmission investment and generation additions considered for the (2026-2040) include completion of the western corridor project, 330 kV Pokuase -Anwomaso Project (K3BSP)., Double Circuit 330 kV Nkawkaw – K3BSP transmission Project, Double Circuit 330 kV Bengerville – Dunkwa transmission Project, 161 kV Eastern corridor transmission line Project, 55 MW Pwualugu Project, 120 MW Karpower phase III at Kumasi, 340 MW AKSA phase II at Kumasi.The expected completion of various transmission lines for both the short and logn term would allow for the increased TTCs starting in 2023.

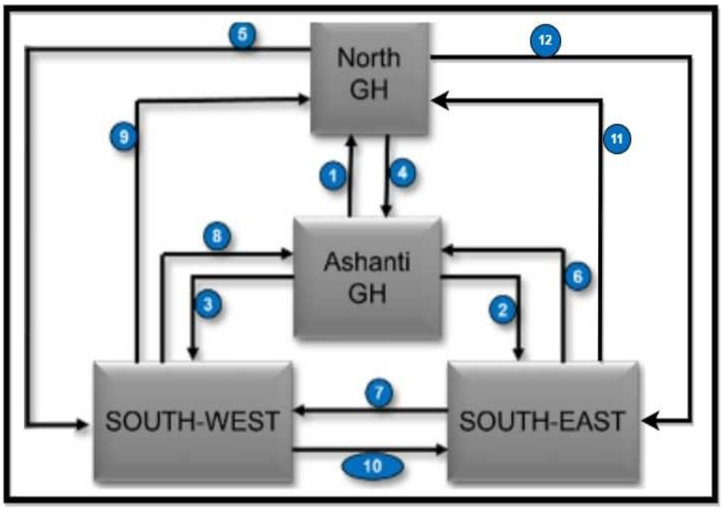


Figure 29: Schematic Diagram of the Transmission Paths

Table 29: Firm and Non-Firm TTCs between Ghana Zones

Link No.	From Ghana Zone	To Ghana Zone	Non-Firm TTC	Firm TTC
	2023–2025			
1	Ashanti	North	1,168.8	579.7
2	Ashanti	South East	432.7	290.4
3	Ashanti	South West	1049	264.8
4	North	Ashanti	760.5	744.2
5	North	South West	142.1	0
6	South East	Ashanti	396.7	259.8
7	South East	South West	539.6	262.3
8	South West	Ashanti	1,109.1	278.9
9	South West	North	94.7	0
10	South West	South East	845.1	335
	2026–2040			
1	Ashanti	North	1,371.9	712.5
2	Ashanti	South East	2,103.8	1182
3	Ashanti	South West	783.9	441.6
4	North	Ashanti	923.9	604.7
5	North	South West	128.5	0
6	South East	Ashanti	1,063.3	987.5
7	South East	South West	1,094.1	448.9
8	South West	Ashanti	1,054.6	585.2
9	South West	North	139.6	0
10	South West	South East	1,267	498.3
11	South East	North	151.5	0
12	North	South East	79.4	0

Source: Ghana Grid Company, 2022

6. LEAST-REGRETS CAPACITY EXPANSION PLAN

The selection of a specific capacity expansion portfolio for the Integrated Power Sector Master Plan (IPSMP) requires a critical consideration and evaluation of how the various policy options and utility business decisions might affect the key metrics for Ghana's power sector. The implications of specific policy options will need to be tested under various sensitivities—that is, under conditions beyond the control of the utilities—to identify and select a **Least-Regrets Portfolio** that is robust under changing circumstances. This chapter discusses the methodology involved in determining a Least-Regrets capacity expansion plan (or the Least-Regrets Portfolio) and the implications of the selected portfolio.

Methodology Overview

A *strategy,* per this study, is defined as a set of modelling assumptions on the policy framework, utility business decisions, load forecasts, technology cost and availability, fuel and renewable energy resource availability, etc. However, the "Least-Regrets" *Strategy* is a set of policy objectives for the power sector that performs the best under a broad range of potential *sensitivities*—i.e., various techno-economic futures. The generation and transmission resource "builds" that derive from this Least-Regrets Strategy are collectively called the Least-Regrets *Portfolio*. This Least-Regrets Portfolio is the resource plan that provides the highest performance under the selected metrics.

The "Reference Case" assumptions discussed in the previous chapter define the Unconstrained Strategy. It represents the least-cost optimised modelling results from the Reference Case assumptions, considering *only* the existing regulatory and policy frameworks, without any technological constraints.

> A **"Least-Regrets" Strategy** is a set of policy objectives for the power sector that performs the best under a broad range of potential techno-economic futures.

However, to identify the Least-Regrets Strategy, several different electricity supply policies/strategies were considered for the Ghana power sector. These strategies represented potential policy options for the power sector that the Government of Ghana could consider. The strategies had their own set of constraints (discussed below) and each were optimised to identify least-cost model solution using the Reference Case model assumptions in the *GH-IPM 2023*.

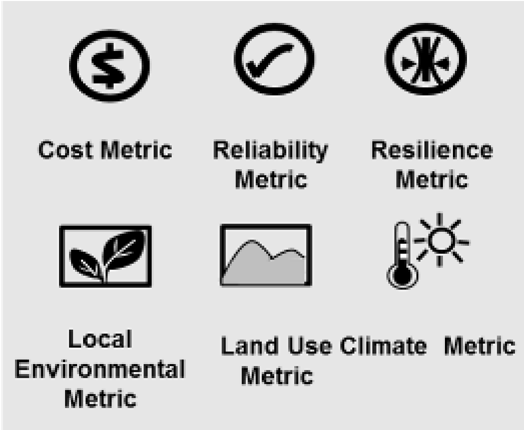
Each of the build portfolios from these different strategies (including the Unconstrained Strategy) under various sensitivities, which were essentially changes to the Reference Case assumptions that will be discussed later in Chapter 6. The optimised build portfolio that was determined using the Reference Case assumptions was fixed when the model was run through each of these sensitivities for each strategy.

This approach represents a situation where the country have essentially decided to build power plants as per the model output with the Reference Case assumptions of the particular strategy. However, these assumptions may not hold true over time (e.g., oil prices or demand forecasts end up being different in the future from the expectations in the Reference Case). Therefore, by fixing the build portfolio for each strategy, and then running the IPM through each of the sensitivities, one can assess the implications of what happens when the techno-economic assumptions are different from the Reference Case assumptions.

For each of these strategy-sensitivity combinations, selected metrics in the categories of cost, reliability, resilience, local environment, land use, and climate were calculated from the model results

These metrics are then statistically analysed to determine a score for each strategy, and the strategies are then ranked based on their scores.

The most cost-effective portfolio that performs generally well under all the selected metrics is considered as Least-Regrets Strategy. Figure 30 summarises the basic methodology used in the identification of the Least-Regrets Portfolio.



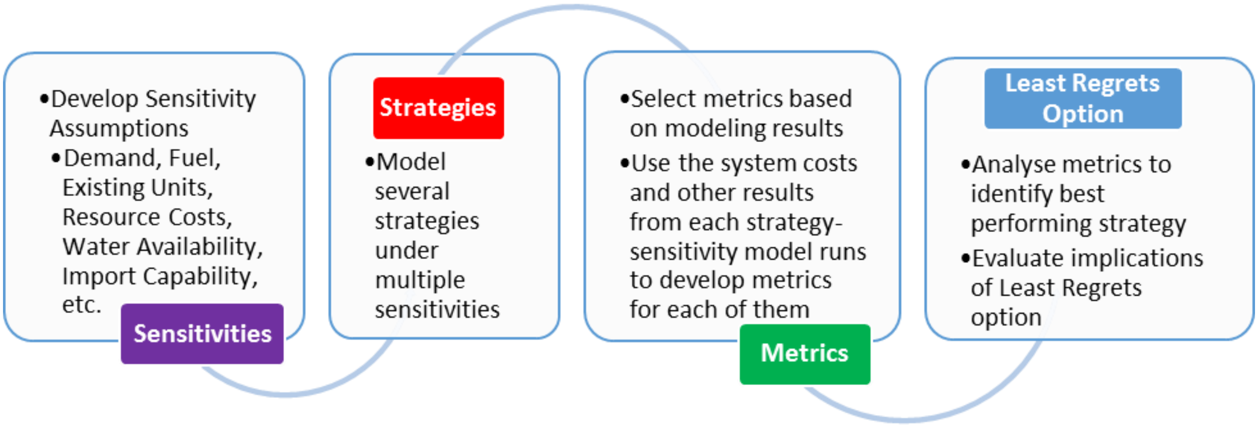


Figure 30: Schematic for Identifying Least-Regrets Option for the IPSMP

6.1. STRATEGIES

The set of different power sector policies (i.e., strategies) considered for the Ghana power sector are shown in Table 30. These strategies are possible policy directions the Government of Ghana could embark on which are similar to the 2019 IPSMP, except for the exclusion of Coal Strategy. The supply strategies are detailed in Table 30.

The focus of the IPSMP analysis was to determine the Least-Regrets Strategy from this array of different strategies, using the methodology discussed above.

Table 30: Strategies Evaluated for IPSMP

#	Strategy Name	Description
I	**Unconstrained**	• Reference Case assumptions on demand, technology costs, gas resource availability, RE bounds, TTCs, build 50MW small hydro • Build 150 MW CC in Ashanti • No other technology-specific constraints on build options
II	Diversify with **Nuclear**	• Reference Case assumptions on demand, technology costs, gas resource availability,

#	Strategy Name	Description
		RE bounds, TTCs, build 50MW small hydro and 150 MW CC • Diversify fuels by building a 1000MW nuclear power plant in 2031 in SouthWest-GH
III	**Diversify Geographically**	• Reference Case assumptions on demand, technology costs, gas resource availability, TTCs, build 50MW small hydro and 150 MW CC • Build additional 180 MW combined cycle plant in Ashanti by 2027 and 250 MW SouthEast-GH by 2029
IV	**Renewable Energy Master Plan** (REMP)	• Reference Case assumptions on demand, technology costs, TTCs, build 50MW small hydro and 150 MW CC • Implementation of on-grid utility-scale RE capacities identified in the Renewable Energy Master Plan (REMP)
V	**Enhanced G-NDC*** Reduced CO_2 growth	• Reference case assumption on demand, technology costs, gas resource availability, TTCs, build 50MW small hydro and 150 MW CC • Constrain CO2 emissions to half of unconstrained strategy emissions.

*G-NDC refers to Ghana Nationally Determined Contributions, which are Ghana's commitments under the Paris Agreement (see Table 55 in Section 10.2)

6.2. SENSITIVITIES

Each of the strategies will have specific build portfolios (both generation and transmission capacities) under the Reference Case assumptions, which are based on median values for the various modelling parameters. The specific capacity expansion plans based on the reference assumptions are known as the "Reference Case" results for a particular strategy. As noted above, to test how the Reference Case results will vary under changing circumstances, the Reference Case build portfolio for each strategy is fixed for the entire modelling/planning duration and tested over a range of "sensitivities". Each sensitivity is a change in specific parameters relative to the reference assumptions. These sensitivities test the potential areas of risks and uncertainties facing the Ghana power sector planning.

For the IPSMP analysis, ten sensitivities were considered under five categories, as indicated in Table 31 The categories are:

1. Demand (high and low)
2. Fuel Price (high and low)
3. Natural Gas Volume (reduced and increased)

4. Technology Capital Cost (high and low RE costs, and low conventional costs)
5. Hydropower Capacity (low)

Although the new capacity builds were fixed to the Reference Case portfolio for most of the sensitivities, the build profile for each strategy was allowed to change after the first six (6) years for the high and low demand growth sensitivities (i.e., sensitivities #1, #2). In other words, if the power sector were indeed to be on a higher or lower demand growth trajectory, then the power planners would certainly have the ability to alter the Reference Case build after 6 years to an optimised build portfolio that takes the high or low demand growth into account. Table 31 describes the sensitivities.

Table 31: List of Sensitivities Modelled for IPSMP

#	Sensitivity	Description
0	Reference Assumptions	• As described in the Modelling Assumptions chapter
1	High Demand Growth	• Demand growth for peak and energy demand exceeds the Reference Case, with an 7.9% long-term average GDP growth, which is consistent with SNEP AEG and NDPC projections
2	Low Demand Growth	• Demand growth for peak and energy demand is lower than the Reference Case, with a 4.1% long-term average GDP growth
3	High Fuel Prices	• Higher LNG, domestic gas, and liquid fuel prices, relative to Reference Case
4	Low Fuel Prices	• Lower LNG, domestic gas, and liquid fuel prices, relative to Reference Case
5	Limited Gas Supply	• Lower domestic gas production
6	Greater Domestic Fuel Supply	• High Case production of domestic gas
7	Limited Water Inflows for Hydro	• Lower hydro generation due to possible climate change impacts; the capacity factor of hydro plants decreases by 25% (Bui) and 30% (Akosombo, Kpong and potential small hydro units) from 2023 to 2040
8	Higher RE Capital Costs	• Higher capital costs for solar, and wind plants, relative to the Reference Case
9	Lower RE Capital Costs	• Lower capital costs for solar, and wind plants, relative to the Reference Case
10	Lower Capital Cost for Conventional Resources	• Capital costs for conventional technologies (CCs, CTs, nuclear, and coal) lower than expected

These sensitivities will depend on the expectations of future risks, and so they can be different for future updates of the IPSMP.

6.3. METRICS

The model outputs from each of the supply strategy-sensitivity combinations were synthesised into specific metrics that represent the vision and the objectives for the IPSMP. In essence, the metrics provide the values that inform decision-making regarding build strategies. Based on the IPSMP vision and objectives, 10 metrics were selected in six different categories: cost, reliability, resilience, local environment, land use, and climate. Figure 31 shows a breakdown of the main categories of metrics into sub-metrics.

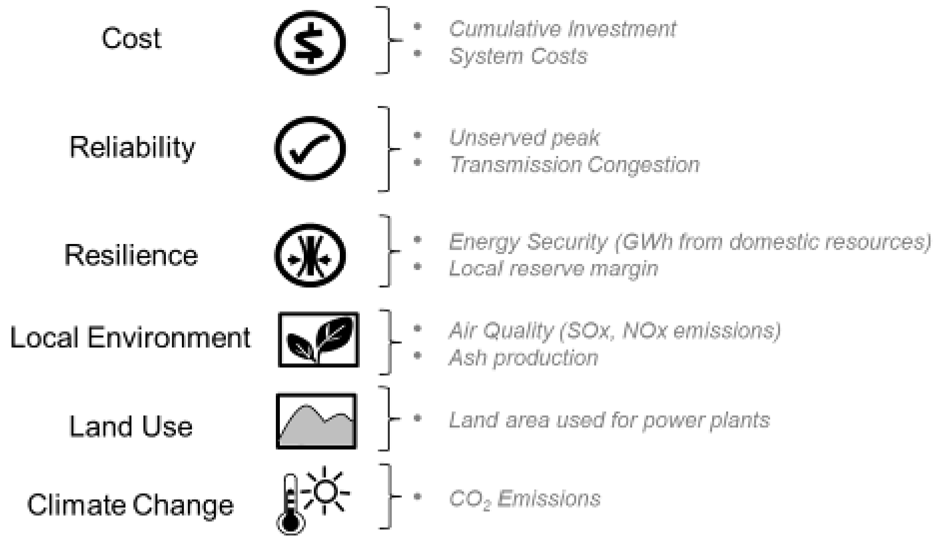


Figure 31: Metrics for Strategy-Sensitivity Combinations

A brief description of these metrics and their relationships to the IPSMP vision and objectives is presented in Table 32.

For each supply strategy-sensitivity combination, these metrics were calculated over the 10-year (2023–2032) and the 18-year (2023–2040) modelling periods. For each strategy, the average was then calculated over the entire range of sensitivities for each metric.

6.4. MODELLING RESULTS

A simple analysis of the supply-demand balance indicates that existing generation and under-construction plants are sufficient to meet the growth in demand in the short-to-medium term. Figure 32 illustrates the simple supply-demand balance chart that shows 2023 and 2024 net generation from existing and under-construction plants along with the projected energy forecast up until 2040, a scenario when there are no challenges with fuel availability. Ameri, and Early Power, which are plants under construction are earmarked to come online at the latest by the early part of 2023 and will cumulatively add about 330 MW of installed capacity to the grid. The simple analysis shows that additional capacity is only needed by the late 2020s, under the reference demand forecast.

Table 32: Details of Metrics for IPSMP

IPSMP Vision	Objectives	Metric	Unit of Measure	Definition
Economic Development	Competitive cost	**Total investment cost**	Millions of 2016 USD	NPV of total capital cost of all new builds
	Competitive cost	**Total system cost**	Millions of 2016 USD	Annualised NPV of total production (VOM + FOM + Fuel) and investment costs
Reliability	Meeting growing demand	**Transmission congestion**	%	Avg. annual % share of time transmission corridors greater than or equal to 80% utilisation
	Meeting growing demand	**Unserved peak**	MW	Cumulative sum of MW not served of total peak demand
Resilience / Reliability	Increase resilience (energy security)	**Energy (GWh) produced using domestic resources**	%	% of generation produced from domestic (fuel) resources relative to total domestic demand
Resilience / Reliability	Increase resilience	**Local reserve**	%	% of local capacity serving local peak demand in the Middlebelt and NEDCo areas
Sustainability	Meet local environmental goals	**Ash production**	Tonnes of ash production	Ash production from coal and biomass-fired power generation
	Meet local environmental goals	**Air quality**	Tonnes of SO_2, NO_x	SO_2 and NO_x emissions from power generation
	Meet sustainability goals	**Land requirements**	Acre/MW	Land required per MW of capacity built
	Meet climate goals	**GHG**	Tonnes of CO_2 emissions	CO_2 emissions from power generation

Although it is a rather simplistic approach to assessing the supply-demand balance, it still clearly shows the need for additional generation capacity for meeting peak demand only after the mid-2020s. A least-cost approach will take into consideration the costs of operating existing plants compared to developing and dispatching new and more efficient power plants. The least-cost approach in IPM considers the reduction of overall system cost over the entire modelling duration. The consideration of cost (and other operational constraints) in the supply-demand balance allows for additional low-cost resources to be developed earlier than indicated by the simple analysis seen in Figure 32—especially if the generation is for lowering energy cost, as opposed to adding to the reserve margin.

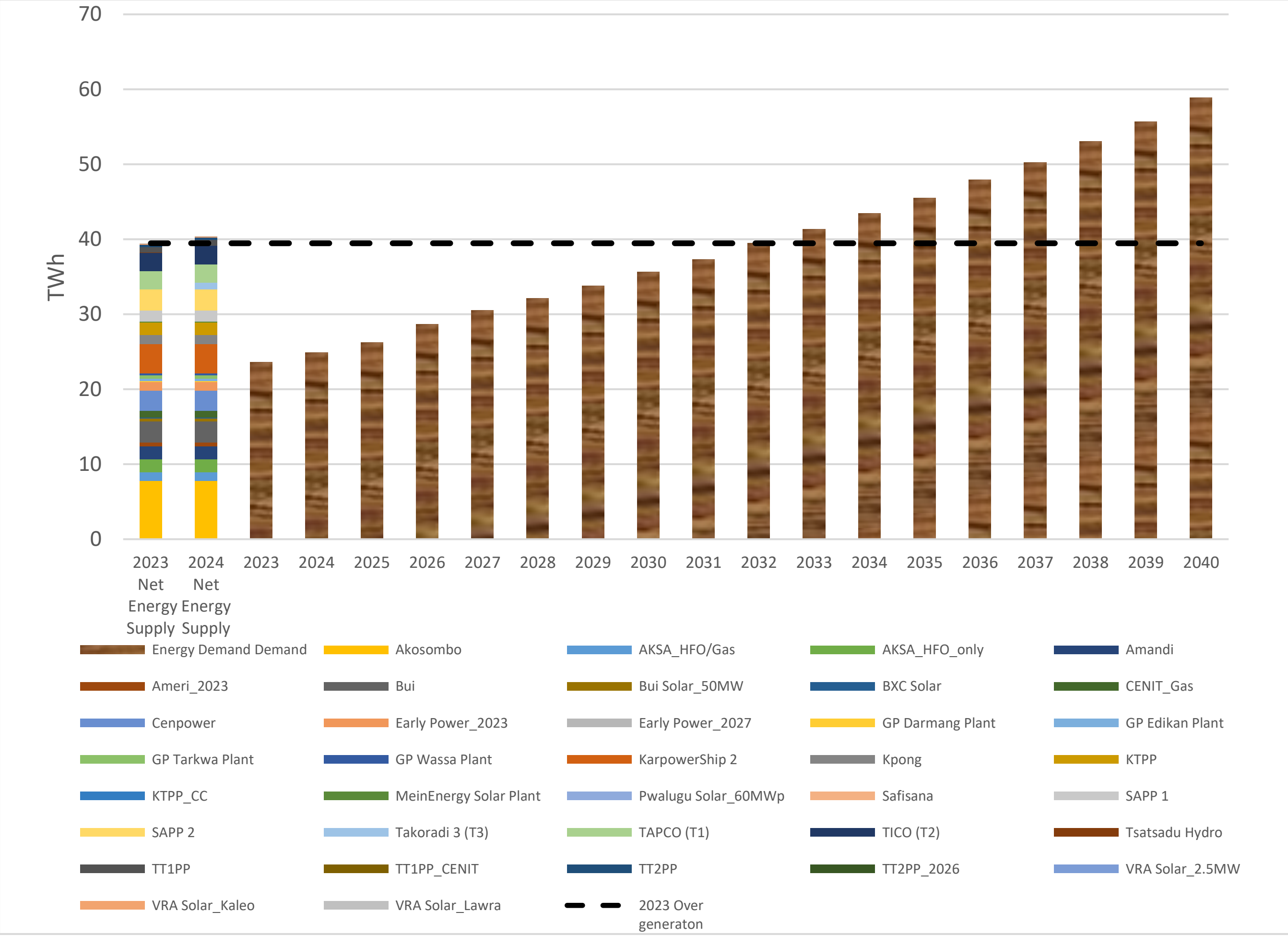


Figure 32: Supply-Demand Balance in Ghana

The subsections below discuss the capacity expansion plans for the various strategies discussed in section 6.1. Each of these capacity expansion results for a specific strategy represents the least-cost optimised solution under the Reference Case assumption (sensitivity #0). A summary of the generation capacity addition for all strategies is indicated in Table 33 and Table 34.

6.4.1. Unconstrained Strategy

Generation Capacity

The Unconstrained Strategy does not have any specific technology constraints, as indicated in Table 30 except with the building of, a small hydropower plant of about 50MW (Pwalugu) in the NorthGH zone and 150 MW CC in Ashanti. The results from this strategy indicate that existing generation and plant capacities under construction are sufficient enough for meeting demand in the short-to-medium term. However, new renewable powerplants come online as early as 2025, primarily due to the relatively lower cost and the relatively high cost of gas. It sees the need to add about 400MW of solar and wind capacities in the near to midterm.

Large thermal power plants, such as a combined cycle plant is only added to the generation mix by the latter part of the 2020s as shown in Figure 33. This strategy has the second highest percentage of renewables in the build portfolio at about 47% over the entire planning horizon.

Table 33: Summary of Capacity Additions (MW) for the 10-Year and Longer Term

	Strategy I		Strategy II		Strategy III		Strategy IV		Strategy V	
	Unconstrained		Diversify with nuclear		Diversify geographically		REMP		Enhanced G-NDC	
Capacity Type	**2023-2032**	**2033-2040**	**2023-2032**	**2033-2040**	**2023-2032**	**2033-2040**	**2023-2032**	**2033-2040**	**2023-2032**	**2033-2040**
Gas Combined Cycle	-	-	-	-	-	-	-	-	7	-
Oil/Gas Combined Cycle	1,490	3,623	928	3,322	1,529	3,623	1,414	3,623	1,705	585
Gas Combusted Cycle	-	-	-	-	-	-	-	-	-	-
Oil reciprocating	-	-	-	-	-	-	-	-	-	-
Biomass Combustion	-	-	-	-	-	-	20	-	35	-
Oil Combustion	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combustion	-	-	-	-	-	-	-	-	-	-
Hydro	50	-	50	-	50	-	70	-	110	-
Solar PV	650	1,640	240	998	650	1,640	1,140	1,690	710	1,640
Solar PV + storage	460	940	-	940	329	940	430	940	590	940
Wind	325	200	325	200	325	200	550	200	325	200
Nuclear	-	-	1,000	-	-	-	-	-	468	2,220
Biogas	-	-	-	-	-	-	-	-	-	-
Conventional Thermal	1,490	3,623	1,928	3,322	1,529	3,623	1,434	3,623	2,215	2,805
Renewable Energy	1,485	2,780	615	2,138	1,354	2,780	2,190	2,830	1,735	2,780
%RE	50%	43%	24%	39%	47%	43%	60%	44%	44%	50%
TOTAL	**2,975**	**6,403**	**2,543**	**5,460**	**2,883**	**6,403**	**3,624**	**6,453**	**3,950**	**5,585**

Table 34: Total Generation (GWh) at the End of the 10-Year and Longer Term

	Current	Strategy I		Strategy II		Strategy III		Strategy IV		Strategy V	
		Unconstrained		Diversify with nuclear		Diversify geographically		REMP		Enhanced G-NDC	
Capacity Type	**2023**	**2032**	**2040**	**2032**	**2040**	**2032**	**2040**	**2032**	**2040**	**2032**	**2040**
Gas Combined Cycle	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,121	1,121
Oil/Gas Combined Cycle	13,439	28,689	44,305	21,470	37,900	28,855	44,471	27,447	42,862	24,014	21,158
Gas Combustion	80	490	490	490	490	490	490	490	490	490	490
Oil reciprocating	473	473	473	473	473	473	473	473	473	473	473
Biomass Combustion	-	-	-	-	-	-	-	-	137	261	261
Oil Combustion	-	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combustion	883	95	95	95	95	95	95	95	95	95	95
Hydro	7,553	6,240	6,240	6,240	6,240	6,240	6,240	6,314	6,314	6,463	6,463
Solar PV	133	1,065	3,197	545	1,863	1,065	3,197	1,745	3,941	1,141	3,273
Solar PV + storage	-	583	1,775	-	1,191	417	1,608	545	1,736	748	1,939
Wind	-	759	1,226	759	1,226	759	1,226	1,284	1,752	759	1,226
Nuclear	-	-	-	8,322	8,322	-	-	-	-	3,898	22,370
Biogas	-	1	1	1	1	1	1	1	1	1	1
Conventional Thermal	15,944	30,816	46,432	31,919	48,349	30,982	46,599	29,574	45,127	30,352	45,968
Renewable Energy (w/L Hydro)	7,687	8,647	12,438	7,545	10,521	8,481	12,271	9,890	13,743	9,112	12,902
Renewable (w/o L Hydro)	649	1,609	5,400	507	3,483	1,443	5,233	2,852	6,705	2,074	5,864
%RE (w/o L Hydro)	**3%**	**4%**	**9%**	**1%**	**6%**	**4%**	**9%**	**7%**	**11%**	**5%**	**10%**
TOTAL	23,630	39,463	58,870	39,463	58,870	39,463	58,870	39,463	58,870	39,464	58,870

*Note that due to the mapped year approach using the IPM modelling, the generation for the run-year 2040 is shown here, as a representative value for the longer term generation.

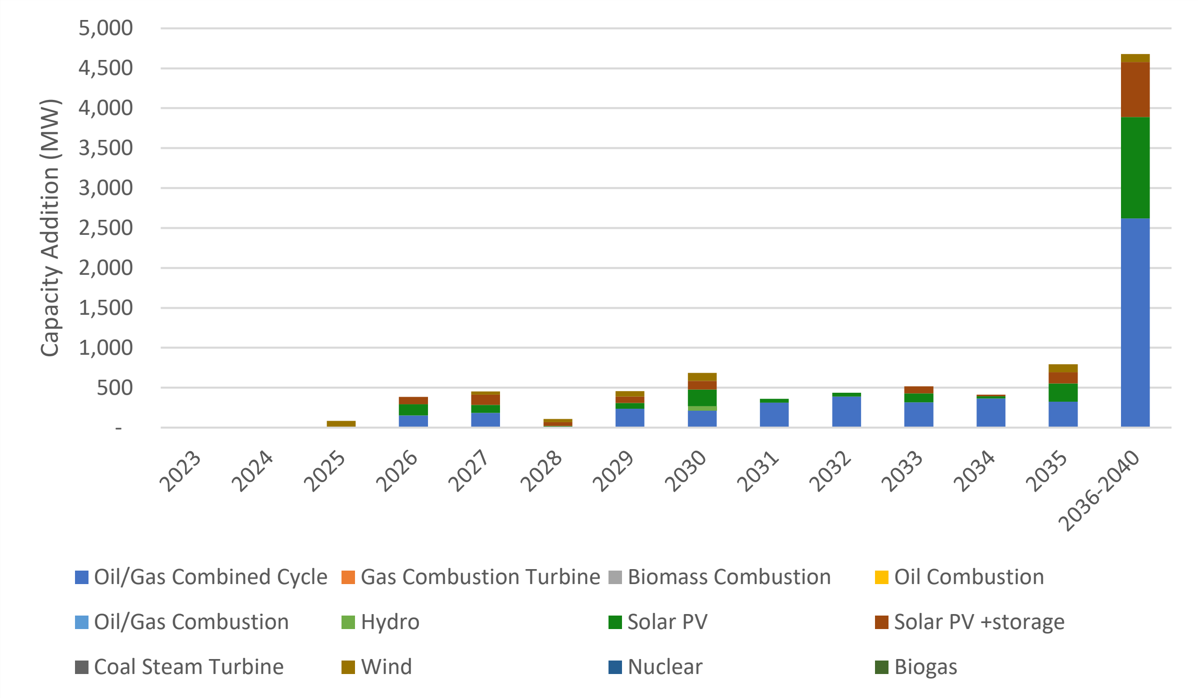


Figure 33: Capacity Additions for Unconstrained Strategy

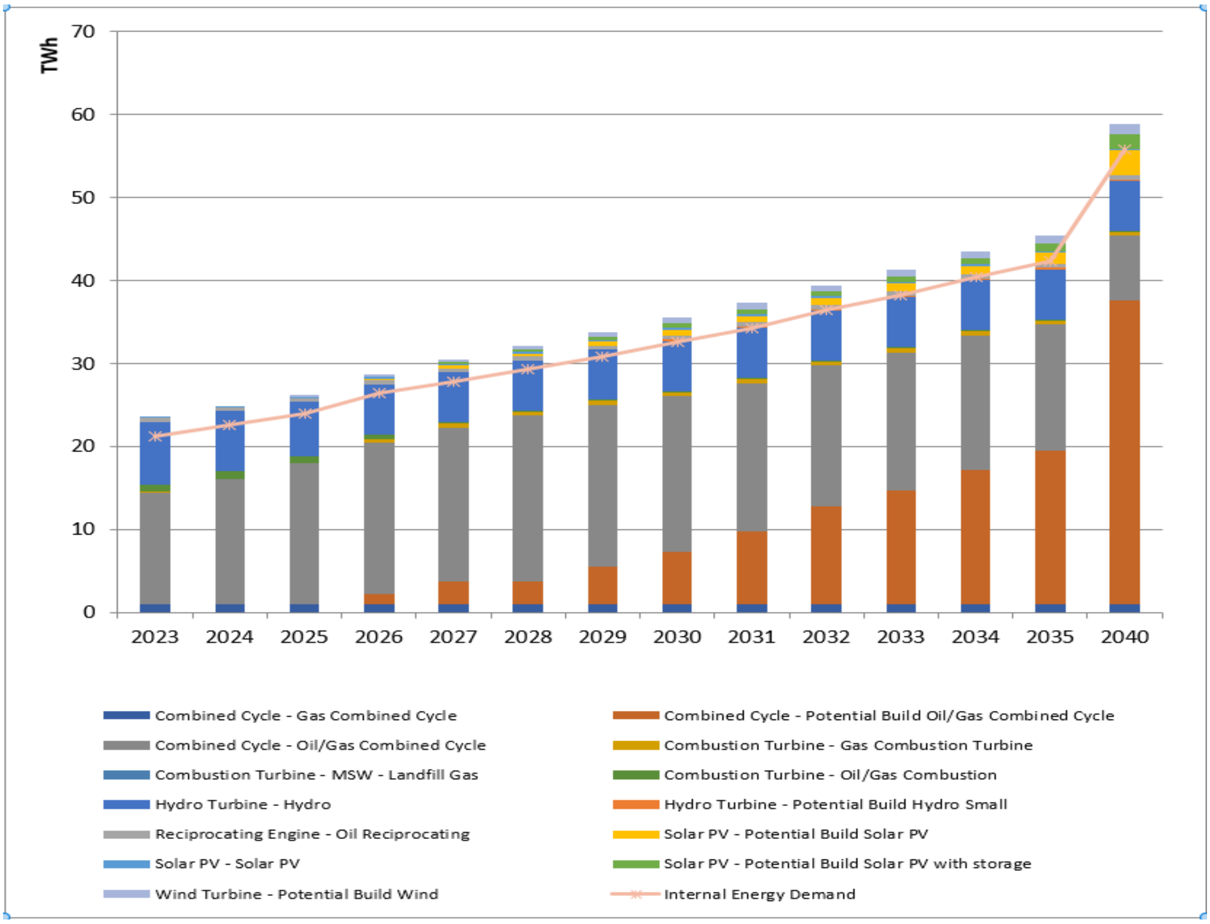
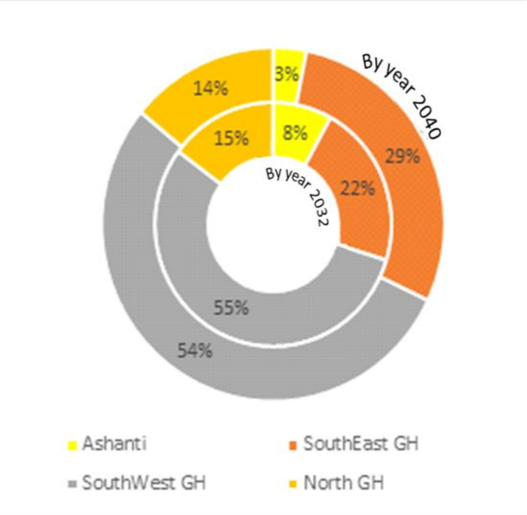


Figure 34: Annual Generation Profile for Unconstrained Strategy

As shown in Figure 33: Capacity Additions for Unconstrained Strategy

, the existing hydro and oil and gas units will continue to significantly contribute to the generation, and by 2032, existing units would contribute about 26 TWh annually. As demand grows, there is a need for new generation units to make up for this growth and to replace the retiring power plants. By the end of the 10-year period in 2032, the new builds contribute about 14 TWh, which increases to 43 TWh by 2040 - representing almost 73% of the total generation in that period after nearly a cumulative of about 9,377 MW capacity added on since 2023.

Figure 35: Distribution of Installed Capacity by Zones for the Unconstrained Strategy



The SouthWest GH zone has the highest share of installed generation capacity in the Ghana zones as shown in Figure 35: Distribution of Installed Capacity by Zones for the Unconstrained Strategy. By the end of 2032, the share of total installed capacity in the zone is about 55%. It slightly decreases, however, to 54% in the long term due to the addition of more plants in the SouthEastGH -primarily combine cycle plants with a cumulative installed capacity of about 3300MW. In addition, about 820MW of Solar PV plants are added in the midterm (2032) in the NorthGH zones representing about 12% of installed capacity. This increases to 14% in the ensuing years of the planning period. In addition, about 20 MW of solar PV capacity was added in the Middlebelt (AshantiGH zone) before 2027 with additional capacity added on in 2030. Solar PV with storage was also built in 2035.

<u>Fuel Consumption</u>

This strategy starts off with about 78% (about 13 TWh) of its annual generation from domestic fuel sources - primarily domestic gas and renewables including large hydro- being able to meet domestic net demand. This increases to 100% in the subsequent years and gradually reduces to about 92% by the end of 2035 primarily due to the increasing reliance on WAGP (N-Gas) due to the reducing volume of the domestic gas reserves. As shown in Figure 36, natural gas is the primary fuel consumed in this strategy. Domestic gas forms the larger share of the volume consumed in the early 2020s after which the need for WAGP (N-Gas) significantly increases from an annual requirement of 9 TBtu in 2023 to a maximum of 40 TBtu by 2035. The need for additional gas comes into play from 2028 with the reducing volume of the existing fields. The additional gas volumes required in this strategy start off with an annual requirement of about 35 TBtu in 2028 and rose to about 121 TBtu per year by 2035. Refer to Figure 36. LNG is consumed under the reference electricity demand case from 2026 but its continuous usage is dependent on the availability and volume of gas from expected new domestic fields – see Figure 36.

The cumulative volume of natural gas needed from 2023 to 2032 is about 12,018TBtu and about 1,700 TBtu between 2033 and 2040.

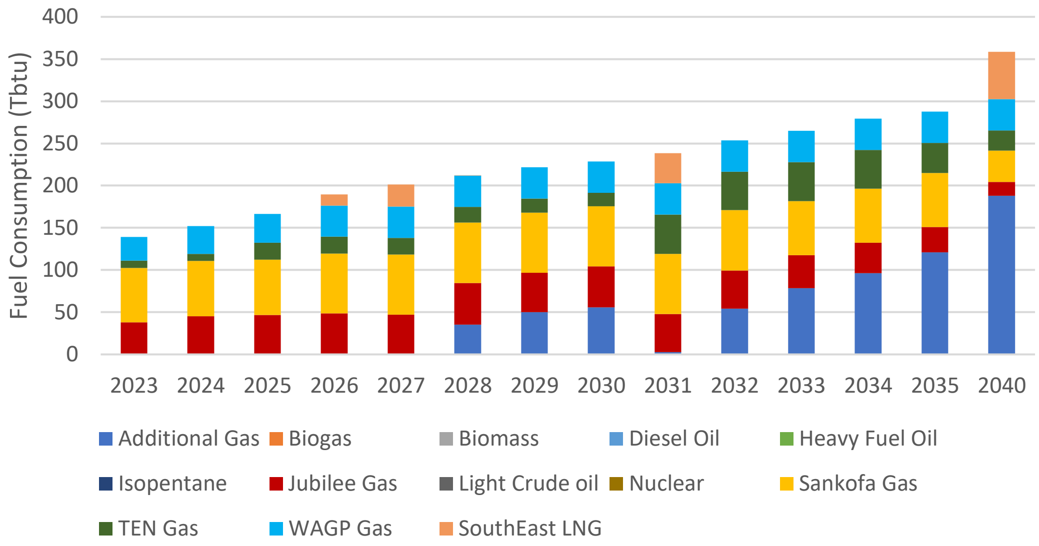


Figure 36: Fuel Consumed by Type in the Unconstrained Strategy

Transmission Capacity

The Unconstrained Strategy requires an upgrade in the transmission network from the SouthWestGH to SouthEastGH, and the SouthWestGH to NorthGH zone. The estimated firm transmission upgrades required for the various planning periods have been summarised in Table 35.

Table 35: Firm Transmission Upgrades Required for Unconstrained Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Span (years)	
		2023-2032	2033-2040
SouthWestGH	SouthEastGH	667	1657
SouthWestGH	AshantiGH	-	-
SouthWestGH	NorthGH	449	350

6.4.2. Diversification with Nuclear Strategy (Strategy II)

Generation Capacity

This supply strategy emphasizes fuel diversity by building a 1000 MW Nuclear plant in SouthWestGH by 2031. Main generation capacity types in this strategy are nuclear, combined cycle, small hydro, solar PV, solar PV with storage and wind.

The addition of a nuclear plant with that much capacity reduces the need for Solar PV by over 1,000 MW. The timing of wind power however is delayed by a year as compared to the reference case. Although about 800 MW of CCs are still needed by 2030 similar to the Unconstrained strategy, the nuclear plant has very much replaced an equivalent capacity of solar and some CC plants. Refer to Figure 37.

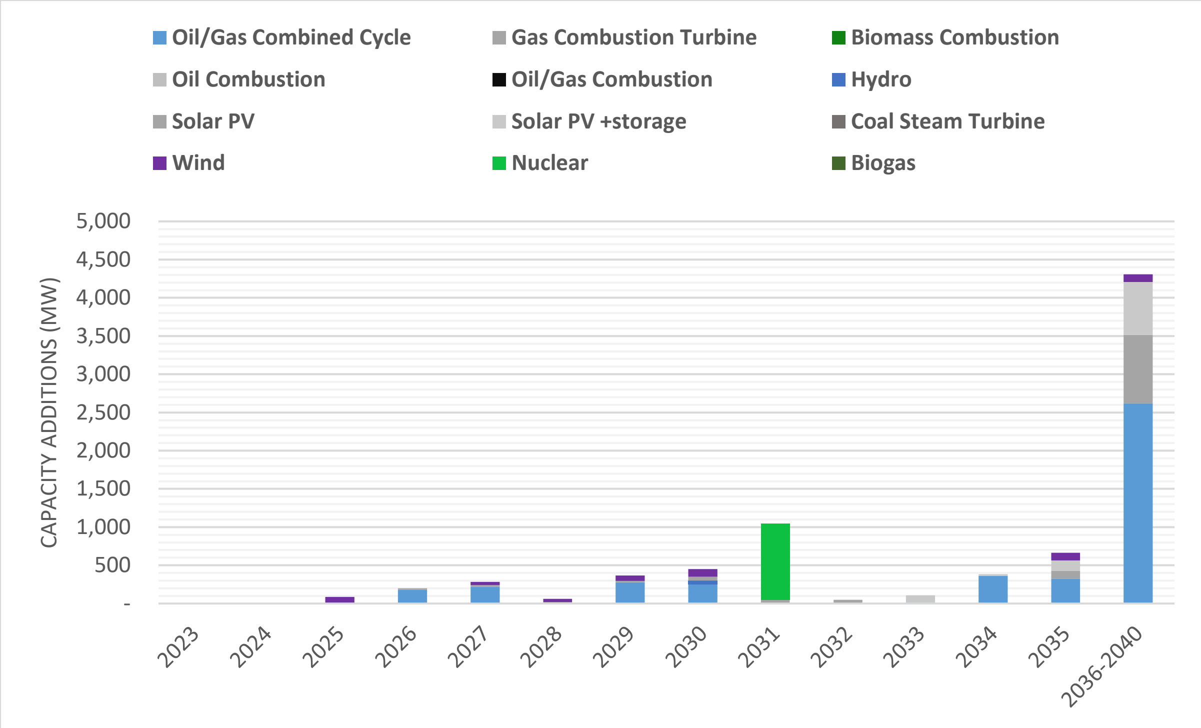


Figure 37: Capacity Additions for the Nuclear Diversification Strategy

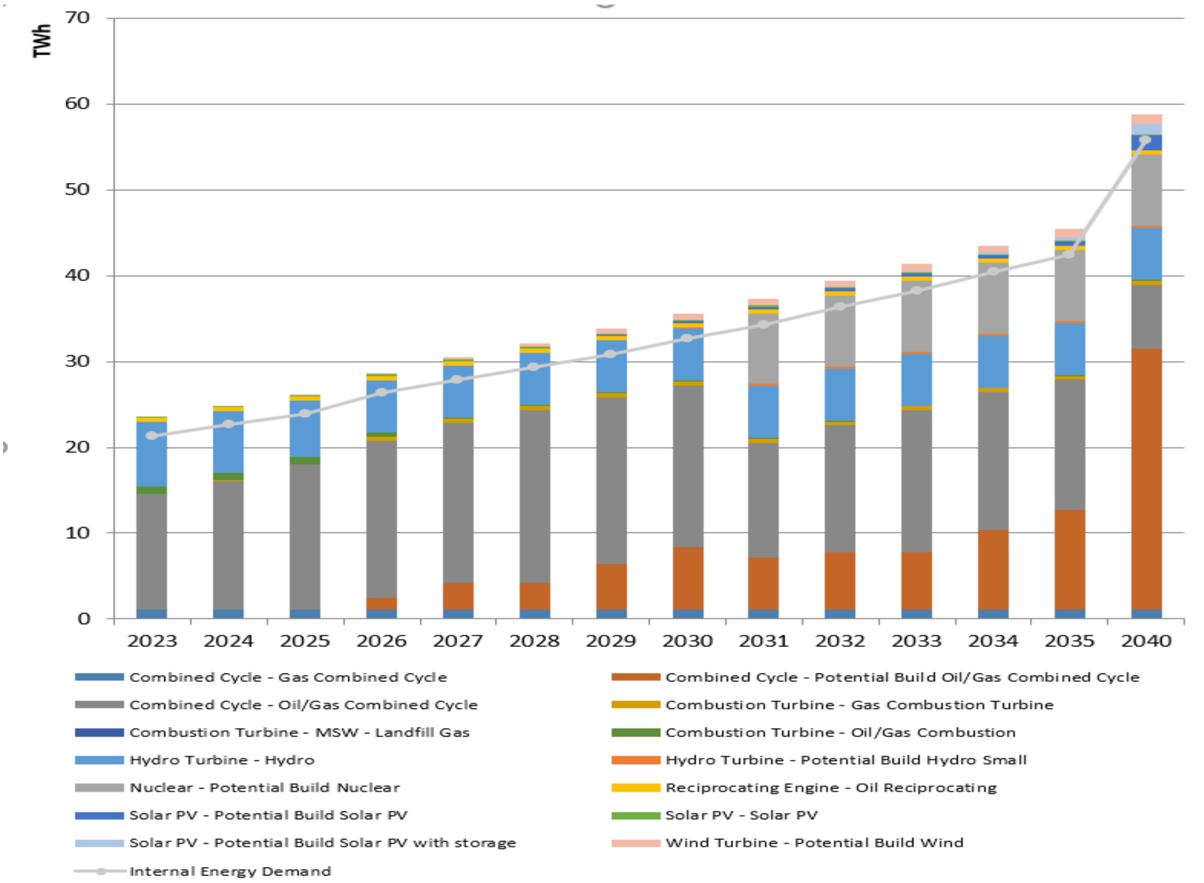
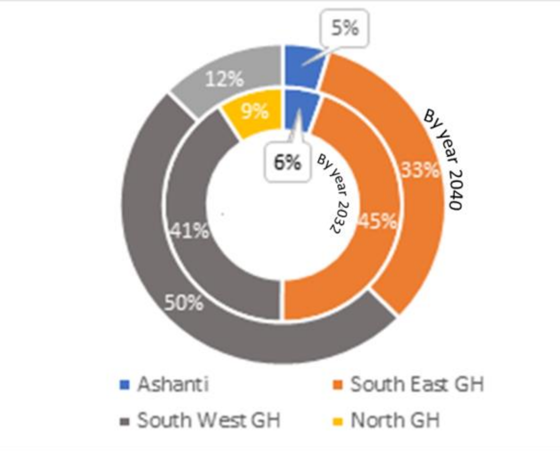


Figure 38: Annual Generation Profile for the diversification with Nuclear Strategy

The difference in generation between Strategy II and the Unconstrained strategies in the first 10 years, is the relatively higher generation in this strategy from existing generators. This strategy also requires less generation from REs, as their installed capacities are reduced. This reduction is because the model accounts for the future development of the nuclear plant and increases the generation of existing plants to meet growing demand before the nuclear plant comes online in 2030. See Figure 37: Capacity Additions for the Nuclear Diversification Strategy

Figure 39: Distribution of Installed Capacity for Nuclear Diversification Strategy



The nuclear plant adds about 8220 GWh to the annual generation from 2031 through to 2040. The nuclear plant "takes away" the generation from existing plants and reduces it by 3,256 GWh relative to the Unconstrained strategy. Cumulative generation from solar and wind is also reduced by as much as 1,102 GWh by the end of 2031 relative to the Unconstrained strategy.

Similar to Strategy I, Strategy II has the SouthEastGH zone as the highest share of installed generation capacity, as shown in Figure 39. By the end of 2032, the share of total installed capacity in the SouthEastGH zone is about 45%, and it decreases to 33% in the longer term due to the addition of relatively more capacities in the SouthWestGH zone—namely, the 1000MW nuclear plant which comes online in 2031. The NEDCO (North Zone) area also relatively increases its share of installed capacities with the addition of solar PVs.

The Middlebelt in this strategy does not have generation capacities added in the near to midterm apart from the 150 MW CC built in 2026. However, similar to Strategy I a total of 90MW solar PV and 70 MW Solar PV with storage plant are added in this region in the longer term.

<u>Fuel Consumption</u>

This strategy, just as Strategy I, starts off in 2023 with a generation requirement of about 23.63 TWh of which about 67% (about 15.94TWh) is projected to come from thermal sources. The thermal share reduces to 58% by 2031 as a result of the coming online of the nuclear power plant.

Natural gas continues to dominate as the primary fuel for electricity generation with uranium usage only coming into the picture in 2031 as shown in Figure 40. Domestic gas continues to have the larger share of the gas consumed for generation (Sankofa, Jubilee, TEN), with the consumption from WAGP averaging about 33 TBtu up to 2030 when nuclear comes online. As demand increases, which gives rise to increasing capacity additions, "Additional Gas" TBtu is needed in small quantities in 2028 (40 TBtu) and rises to about 71TBtu by 2035. However, due to the introduction of a nuclear plant in 2031, the quantity of gas needed for generation reduces from 237 TBtu in 2030 to 183 TBtu in 2031.

The cumulative volume of natural gas needed from 2023 to 2030 is about 1,489 TBtu and about 1,362 TBtu between 2031 and 2040 compared to the 1,563 TBtu and the 1,722 TBtu respectively realised in the Unconstrained strategy.

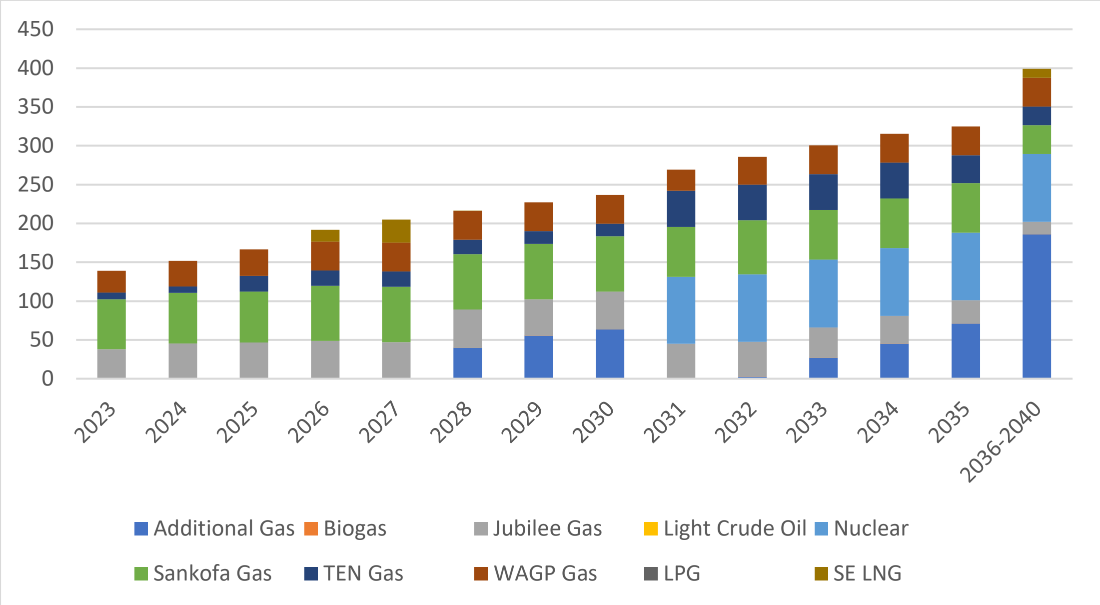


Figure 40: Fuel Consumed by Type for the diversification with Nuclear Strategy

Transmission Capacity

This strategy also requires a significant upgrade in the transmission network from the SouthWestGH to the NorthGH zone, and SouthWestGH to the SouthEastGH zone. Details of the estimated transmission upgrades needed from 2023 to 2040 are indicated in Table 36. The table also shows the difference in the transmission upgrade from the Unconstrained strategy.

Table 36: Transmission Upgrades Required for Nuclear Strategy

Destination Transmission Region Group	Strategy II _Reference Builds		Difference from Strategy I	
	2023-2032	2033-2037	2023-2032	2033-2037
SouthEastGH	724	2276	57	619
AshantiGH	-	-		
NorthGH	503	380	54	30

* **positive & negative implies greater than or less than Strategy I respectively.**

Diversification of Geographic Location Strategy (Strategy III)

Generation Capacity

This strategy aims at diversifying the geographical location of the plants given that the majority of generation units are concentrated in the SouthEast and SouthWest Zone, especially SouthWest Zone. The unconstrained strategy has a 150MW CC built due to government policy to increase generation in the middle belt to support industrialisation efforts and for grid stability. This strategy, therefore, builds a 250 MW and 220 MW CC plant in SouthEast in 2029 and 2030 respectively. In addition to this, this strategy adds a 180 MW CC in the middle belt in

2028. Result from the reference assumptions, indicate that, the added middle belt plant (180 MW CC) is economically dispatched with an average capacity factor of 90% from 2028 through to 2035. The added SouthEast plants, however, begin with a capacity factor of about 90% in 2029 which decreases to about 15% by 2034. On the whole, under reference assumptions the 2023 IPM results for this strategy (Strategy III) performs best in terms of resilience over the entire planning period, having relatively less congestion on the transmission paths and higher local reserve in the middle part of the country. For instance, the resilience metric for the Diversify Geographically Strategy has a resilience metric of 78% as against 69% for the unconstrained strategy.

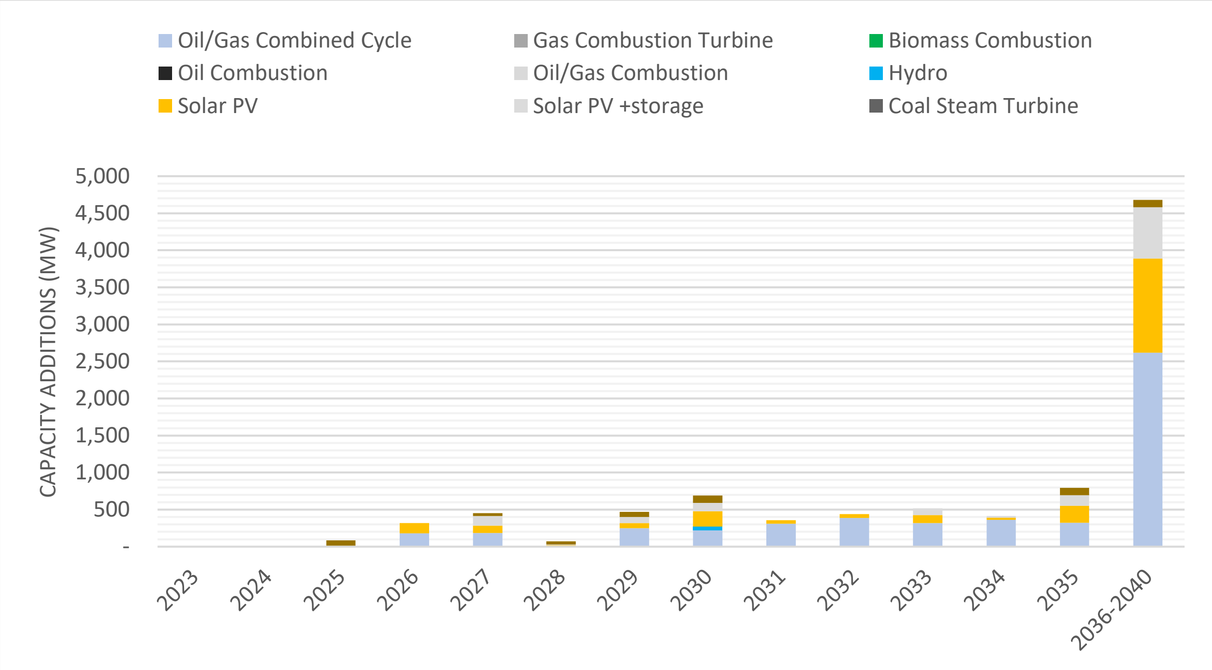


Figure 41: Capacity Additions - Diversification of Geographic Location Strategy

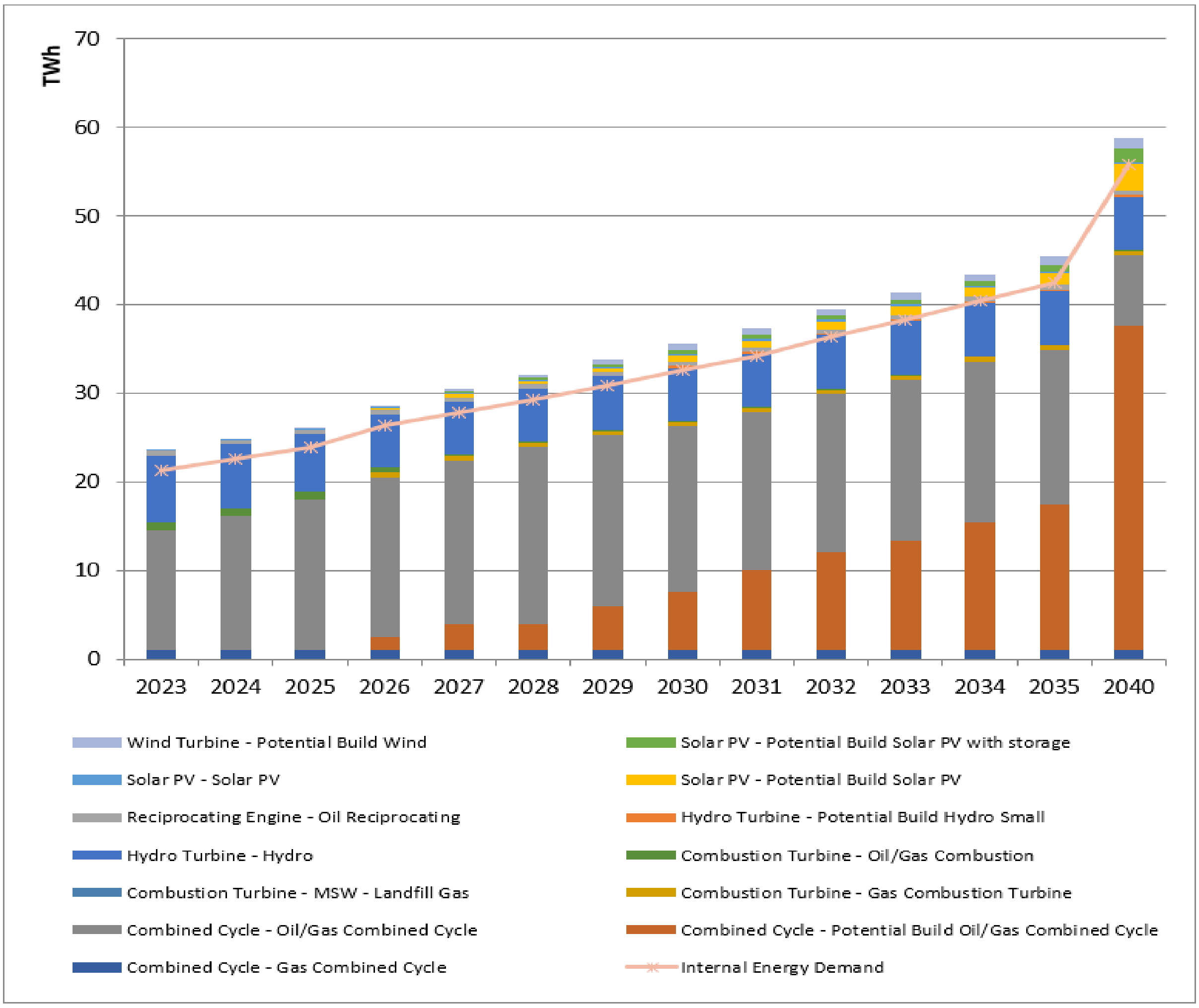


Figure 42: Annual Generation Profile - Diversification of Geographic Location Strategy

Besides the builds in Ashanti and South East, the main difference between the Unconstrained strategy and this strategy in terms of thermal build pattern is the extra 2,183 MW built in the SouthWest zone in 2027.

In terms of REs, there isn't any significant difference between solar builds in this strategy and the Unconstrained strategy. Similar to the Unconstrained strategy, this strategy also adds a total of about 2,290 MW of Solar PV throughout the entire planning period.

Figure 43: Distribution of Installed Capacity for Geographic Diversification Strategy

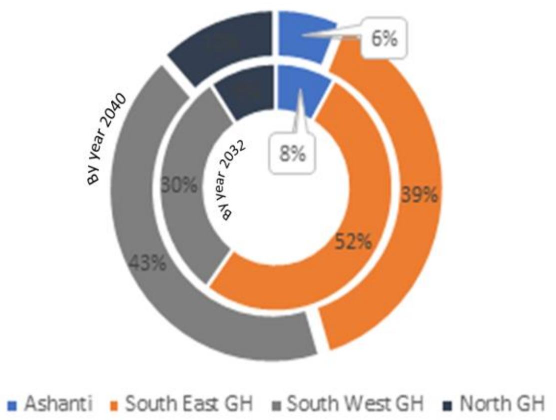


Figure 43 shows the distribution of installed capacity in this strategy across the four zones in Ghana in the shorter and longer terms. This strategy by far has the highest share of installed capacity in the middle belt (AshantiGH zone). With Ashanti recording 6-8% throughout the planning period, there is bound to be the added cost benefit of transmission loss reduction in this strategy. Another difference between this strategy and the Unconstrained strategy is the reduced installed capacity in SouthWest in the medium term.

Fuel Consumption

This strategy just as Strategy I, starts off in 2023 with a generation requirement of about 24 TWh of which about 67% (about 16 TWh) is projected to come from thermal sources. The share of thermal generation increases to 79% by 2032 as a result of the added CC in the Ashanti and SouthEast Zones.

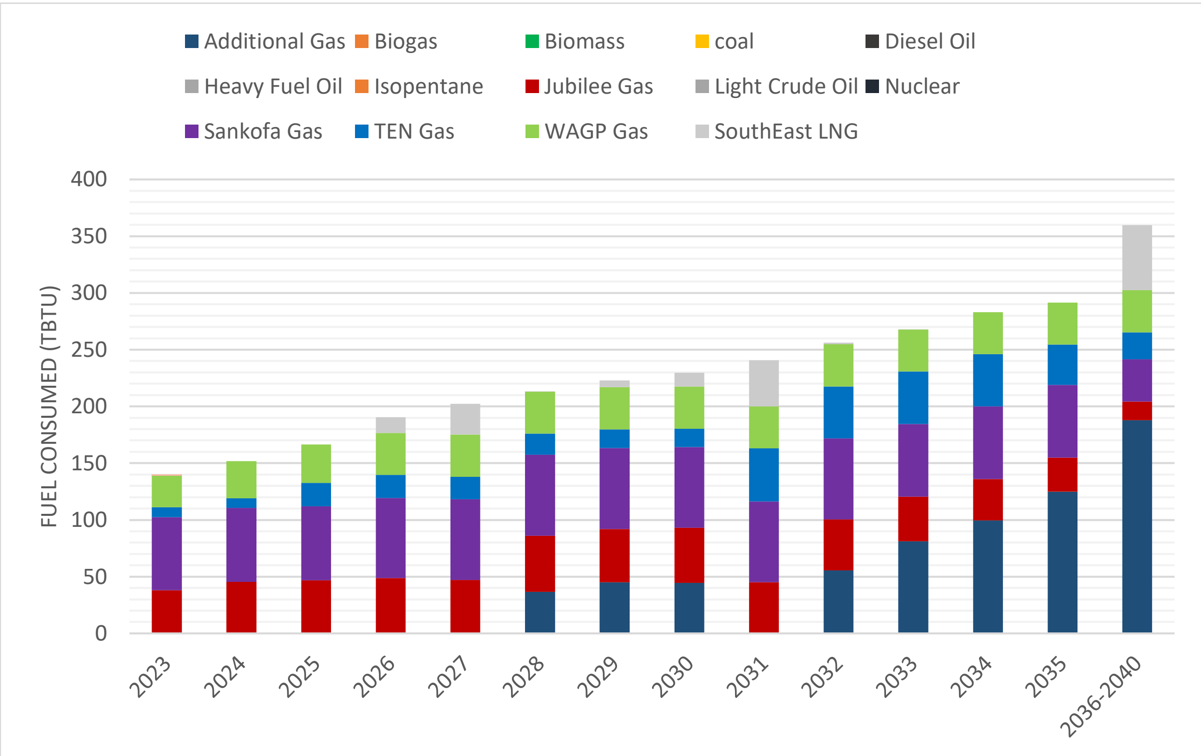


Figure 44: Fuel Consumed by Type for the Geographic Diversification Strategy

Natural gas continues to dominate as the primary fuel for electricity generation with cumulative volume needed between 2023 to 2032 being about 2,013 TBtu and about 1,202 TBtu between

2033 and 2040 which is not very different from the gas requirement of the Unconstrained strategy.

Domestic gas has the larger share of the total gas consumed for generation (Sankofa, Jubilee, and TEN), until about 2027 when there is a need for additional import through the South East LNG just like the Unconstrained Strategy. As demand increases, which gives rise to increasing capacity additions, “Additional Gas” 37 TBtu is needed in 2028 and rises to about 125 TBtu in 2035.

Transmission Capacity

This strategy also requires upgrades in the transmission network from the SouthWest to NEDCo area and the SouthEast. The details for the estimated total transmission upgrades for the 10-year and the long-term periods are indicated in Table 37. The table also shows the difference in the transmission upgrade from the Unconstrained strategy. This strategy requires no transmission upgrades in the SouthWestGH to AshantiGH just as the Unconstrained strategy. This is mainly because of the cumulative 230 MW of CC built in the AshantiGH zone. This capacity would meet a significant portion of the local demand.

Table 37: Transmission Upgrades for Geographic Diversification Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy III _Reference Builds		Difference from Strategy I	
		2023-2032	2033-2037	2023-2032	2033-2037
SouthWestGH	SouthEastGH	206	2268	-461	611
SouthWestGH	AshantiGH	-	-		
SouthWestGH	NorthGH	299	350	-150	0

* **positive & negative implies greater than or less than Strategy I respectively.**

6.4.4. Renewable Energy Master Plan (REMP) – (Strategy IV)

Generation Capacity

This strategy implements the on-grid utility-scale RE capacities identified in the Renewable Energy Master Plan. However, it allows for other technologies to add to the builds once there is the need to build more due to demand growth. So, the main capacity types which were in the REMP, and were implemented in the Ghana IPM, are solar PV, biomass, small hydro and wind. In addition to this, the model economically built solar with storage and combined cycles.

Compared to Strategy I, capacities come on earlier, with about 75 MW of wind and 50MW Solar PV coming online as early as 2023. However, relatively small capacity of PVs come online in subsequent years and is cumulatively higher than the Unconstrained Strategy by 540 MW over the study period. The timing of CCs comes online at much the same time as the Unconstrained strategy and with similar cumulative capacities of about 5,000 MW. Refer to Figure 45.

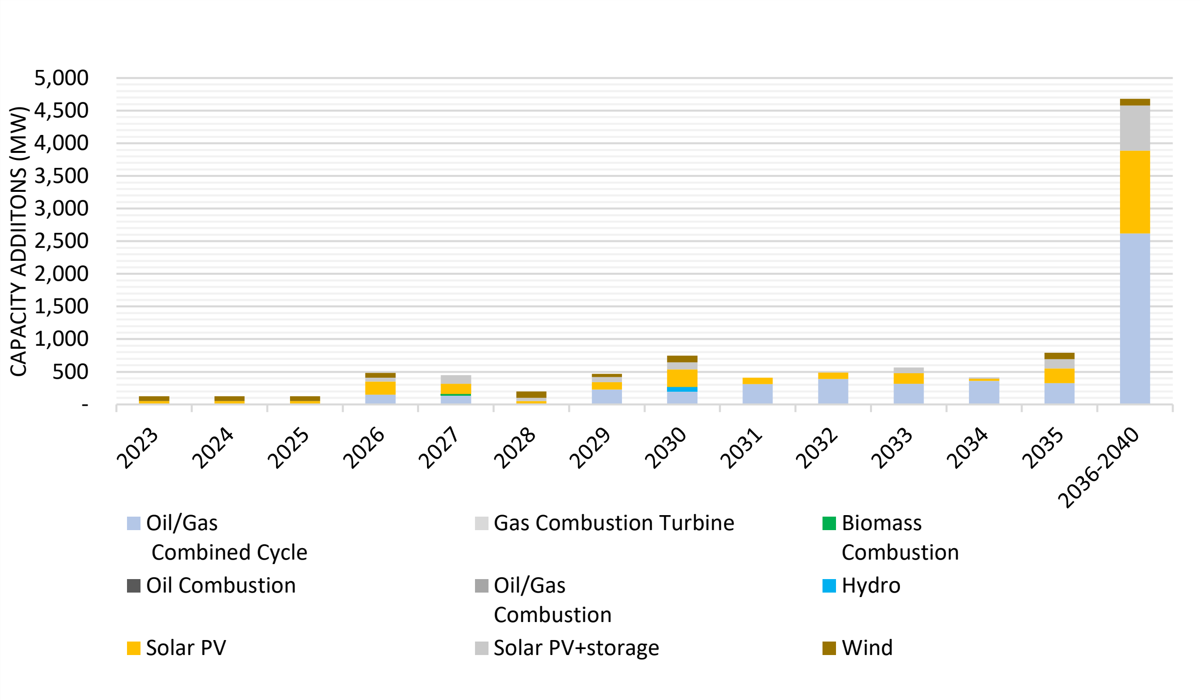


Figure 45: Capacity Additions for the REMP Strategy

Same as with the rest of the strategies, the characteristics of the existing hydro and oil and gas units' contribution remain the same. By 2032, gas generation represents about 75% of total demand with renewable including large hydro representing just 25% (and about 8% without large hydro).

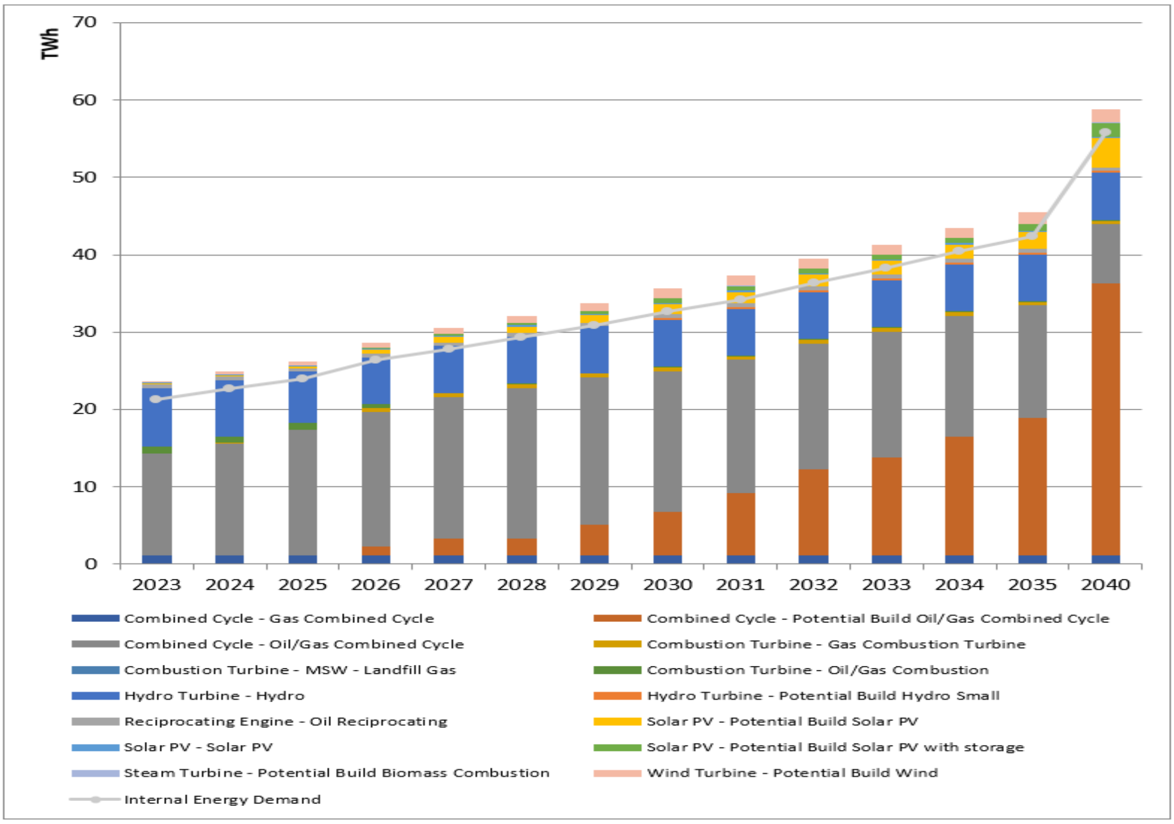
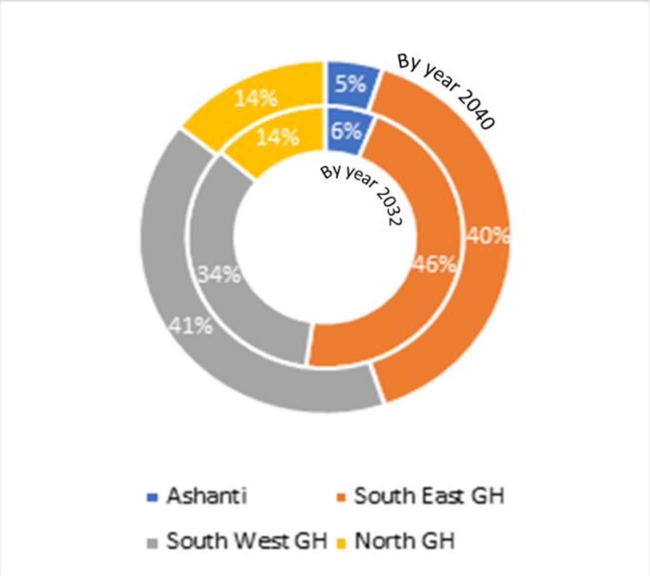


Figure 46: Annual Generation Profile for the REMP Strategy

However, as demand grows, there is a need for new generation units to provide for both peak and energy, hence the addition of more conventional plants thus increasing gas generation units to 76% by 2040 whilst the percentage of RE generation (without large hydro) the energy mix increasing to 10%. In comparison, the Unconstrained strategy had relatively less generation from REs, with the percentage of RE generation without large hydro within the 10-year being 7%. See Figure 46 for the generation pattern for this strategy.

Figure 47: Distribution of Installed Capacity by Zones for the REMP Strategy



This strategy has relatively fewer builds in the SouthWest and more in all the other zones than the Unconstrained strategy. The share of installed capacities across the zones in 2023 is about 58% in the SouthEast, 28% in the SouthWest and about 9% and 5% in the North and Ashanti. However, this changes with time, as more capacities are added in the SouthWest and there is only a marginal increase of capacity in the NorthGH due to the addition of a small hydro plants. The Middle-belt region, however, only sees the addition of a 20 MW biomass plant by 2027 whilst Solar PV and Solar PV with storage equalling about 30 MW by 2035 just as the unconstrained strategy.

Fuel Consumption

On average, across the planning period, about 95% of domestic demand was met with domestic fuel sources such as gas from local fields (i.e., Jubilee, Sankofa, TEN), solar, hydro and biomass.

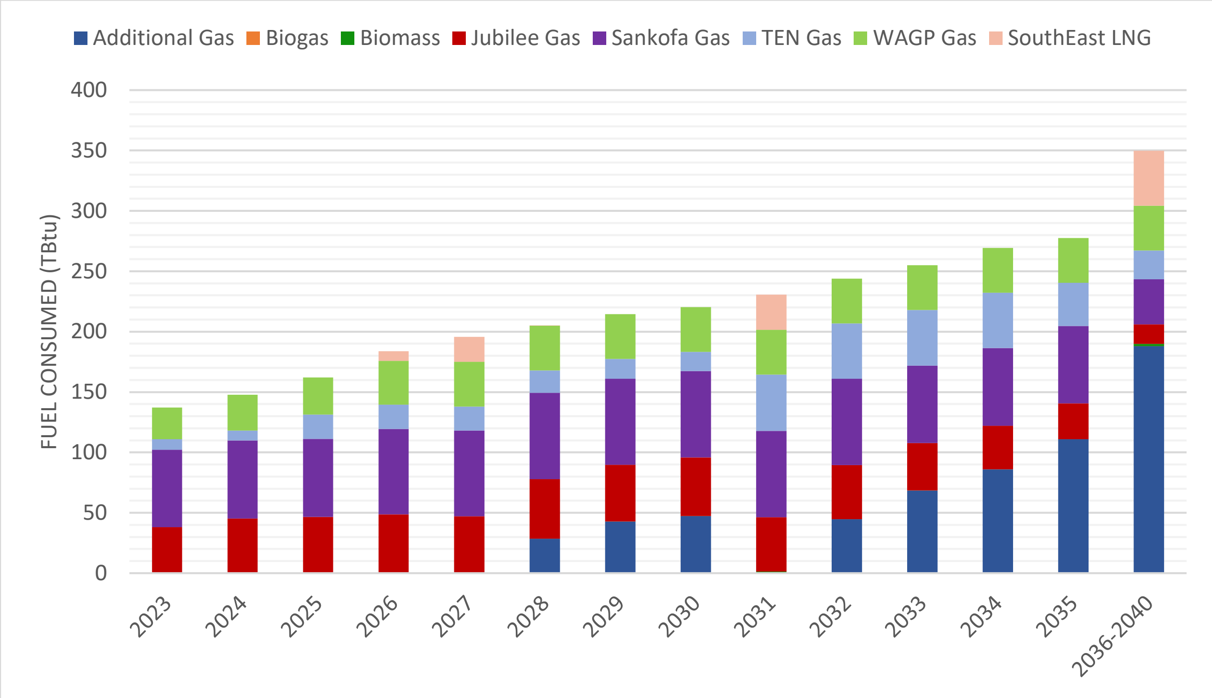


Figure 48: Fuel Consumed by Type for the REMP Strategy

Natural gas continues to dominate as the primary fuel for electricity generation with cumulative volume needed between 2023 to 2032 being about 1,939 TBtu and about 1,150 TBtu between 2033 and 2040 which is slightly less than the Unconstrained strategy which requires 2,069 TBtu and 1,217 TBtu in the 10-year and the long term respectively.

In this strategy also, domestic gas has the larger share of the total gas consumed for electricity generation. LNG is needed in 2026, similar to the Unconstrained Strategy, which starts off from an annual consumption of about 13.2 TBtu in 2026 and increases to about 35.9 TBtu by 2031. “Additional Gas” is needed in small quantities starting in 2028 (~ 36 TBtu) and rises to about 121 TBtu in 2035.

Transmission Capacity

This strategy requires relatively less transmission upgrade in transmission network than the other strategies. Just as with the Unconstrained Strategy, the upgrades required are for only the SouthWest-to-SouthEast and the SouthWest-to-North corridors. Practically no upgrade is required on the SouthWest-to-Ashanti path, which is similar to other strategies.

The estimated transmission upgrades for the transmission paths are indicated in Table 38.

Table 38: Transmission Upgrades Required for the REMP Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy IV _Reference Builds		Difference from Strategy I	*
		2023-2032	2033-2037	2023-2032	2033-2037
SouthWestGH	SouthEastGH	631	1,733.07	-36	76
SouthWestGH	AshantiGH	-	-		
SouthWestGH	NorthGH	409	349.73	-40	0

positive & negative implies greater than or less than Strategy I respectively.

6.4.5. Enhanced G-NDC (Strategy V)

Generation Capacity

This strategy aims at reducing the growth of CO_2 emissions from electricity generation in the power sector, which in turn significantly increases renewable energy and nuclear capacity. In the short-to-medium term, this strategy requires a new biomass (10 MW), Solar PV (30MW), and Solar PV with Storage (50 MW) plants to come online in 2023, which was not needed in the Unconstrained strategy. Compared to the Unconstrained strategy, over the planning period, an extra;

- 70 MW of solar PV
- 130 MW Solar PV with storage
- 60 MW small hydro
- 35 biomass plant

comes online to meet energy and peak and also to have a reduced emission from electricity generation. In the long term, a significant increase in installed capacity of solar with storage is seen (over 1,430MW compared to 1,219MW in the Unconstrained strategy). Additionally, this strategy adds on a 2,688 MW nuclear plant in the mid-2030s, in order to meet the more stringent CO_2 emissions reduction. These RE and nuclear plants have potentially replaced some of the CCs which were seen in the Unconstrained strategy. Refer to Figure 49 for capacity additions in this strategy.

All of these new RE and nuclear builds are necessary to meet the CO_2 emissions trajectory imposed in this strategy. Not surprisingly, this strategy has the lowest total CO_2 emissions and CO_2 intensity as shown in Figure 50 and Figure 51.

Same as with the previous strategies, the characteristics of the existing hydro and oil and gas units' contribution remain the same. By 2032 generation from thermal units (gas) represented about 66% of total generation, renewable including large hydro making up 24% and nuclear making up the rest at 10%.

However, as demand grows, there is a need for new generation units to provide for both peak and energy and also meet emission targets, hence the addition of more solar PV and solar with storage plants and more nuclear builds as compared to the Unconstrained strategy. The nuclear builds reduce the percentage of RE in the generation mix to about 22% with the inclusion of large hydropower generation and about 12% when large hydro is excluded by 2040. This strategy also sees nuclear contributing about 22.4 TWh (about 38% of total generation) by 2040. See Figure 52 for the generation pattern for this strategy.

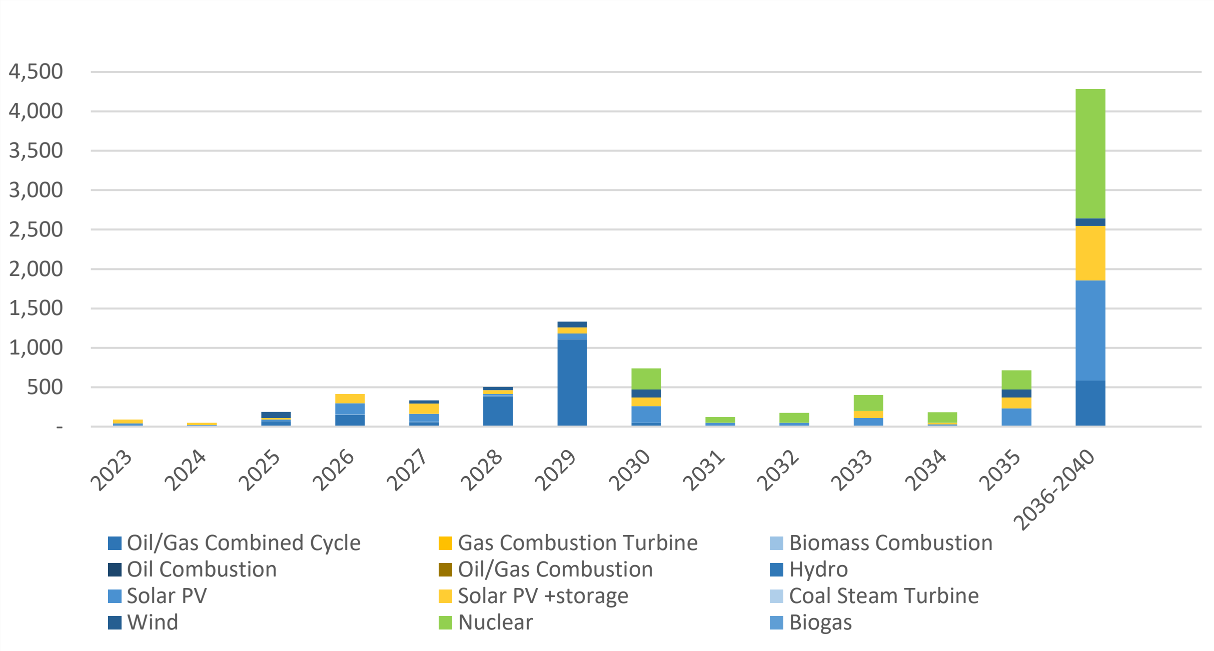


Figure 49: Capacity Additions for the Enhanced G-NDC Strategy

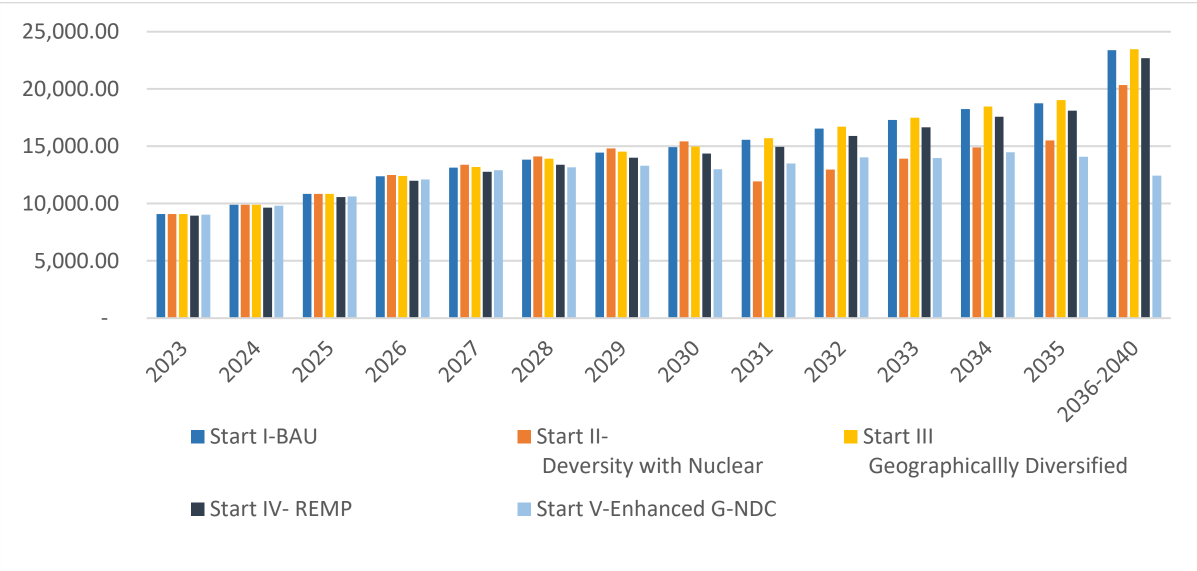


Figure 50: Total CO2 Emission for all Strategies

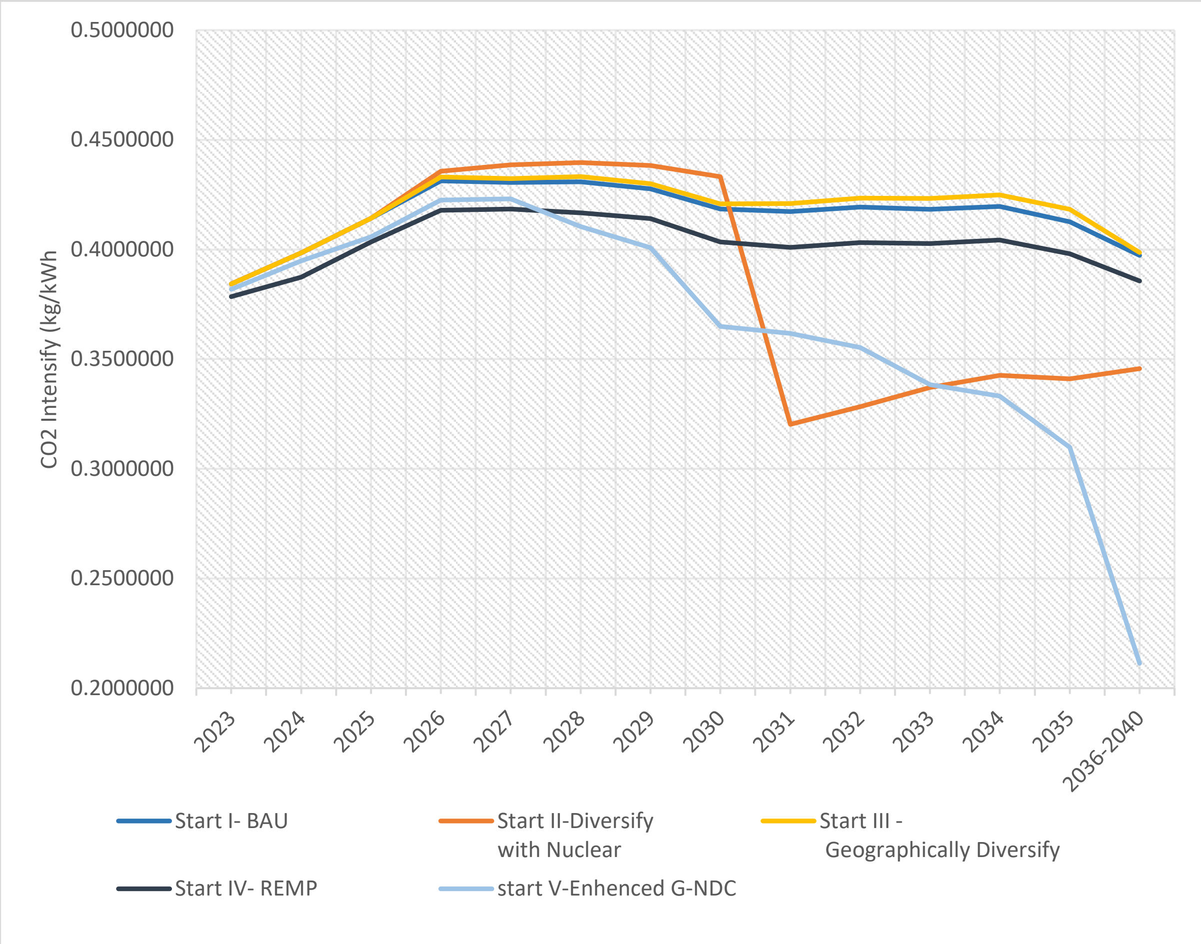


Figure 51: Comparison of CO2 Intensity for all Strategies

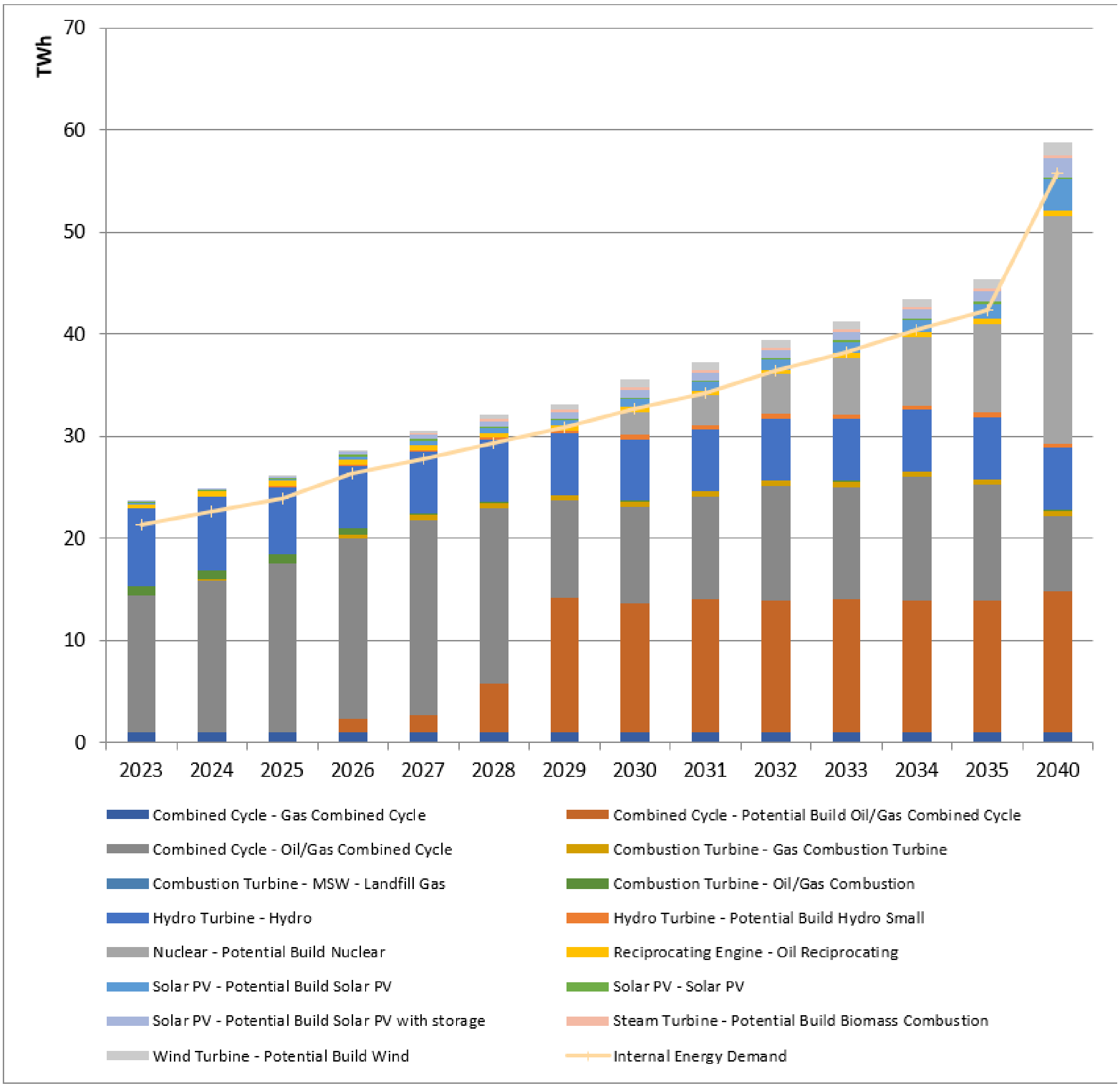
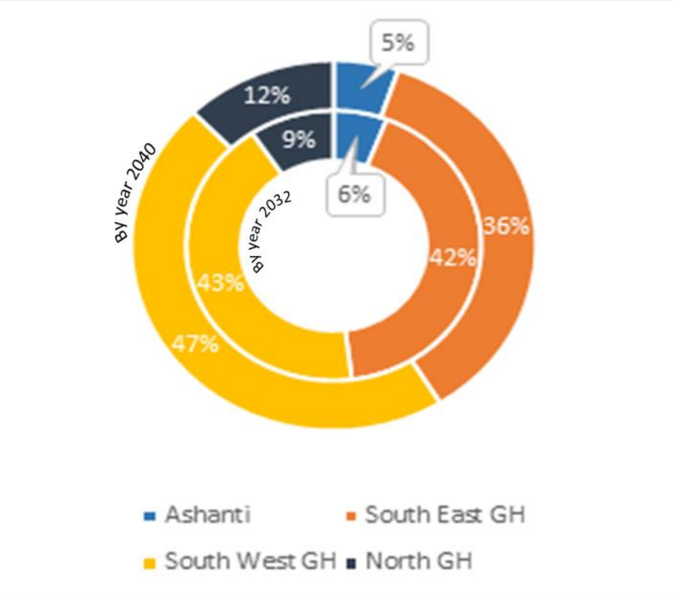


Figure 52: Annual Generation Profile for the Enhanced G-NDC Strategy

Figure 53: Distribution of Installed Capacity for Enhanced G-NDC Strategy



The share of installed capacities across the zones in 2023 is about 658% in the SouthEast, 29% in the SouthWest and about 8% in the North. However, just like the previous strategies, the distribution across the zones changes with time as indicated in Figure 53. More capacities are added in the SouthWest, and the capacity even in Ashanti Zone increases to about 5% by 2040.

For the north zone, more solar PV units are added which increase from 9% to 14% from 2023 to 2032 and then 15% by 2040.

Fuel Consumption

On average, across the planning period, about 95% of domestic demand was met with domestic fuel sources such as the domestic gas from local fields (i.e., Jubilee, Sankofa, TEN), solar, hydro and biomass.

In this strategy, natural gas dominates as the primary fuel for electricity generation in the medium term with cumulative volume needed between 2023 to 2032 being about 1,862 TBtu and about 843 TBtu between 2033 and 2040 which is relatively lower than gas requirement for the unconstrained due to the availability of alternative fuel used by the nuclear plant.

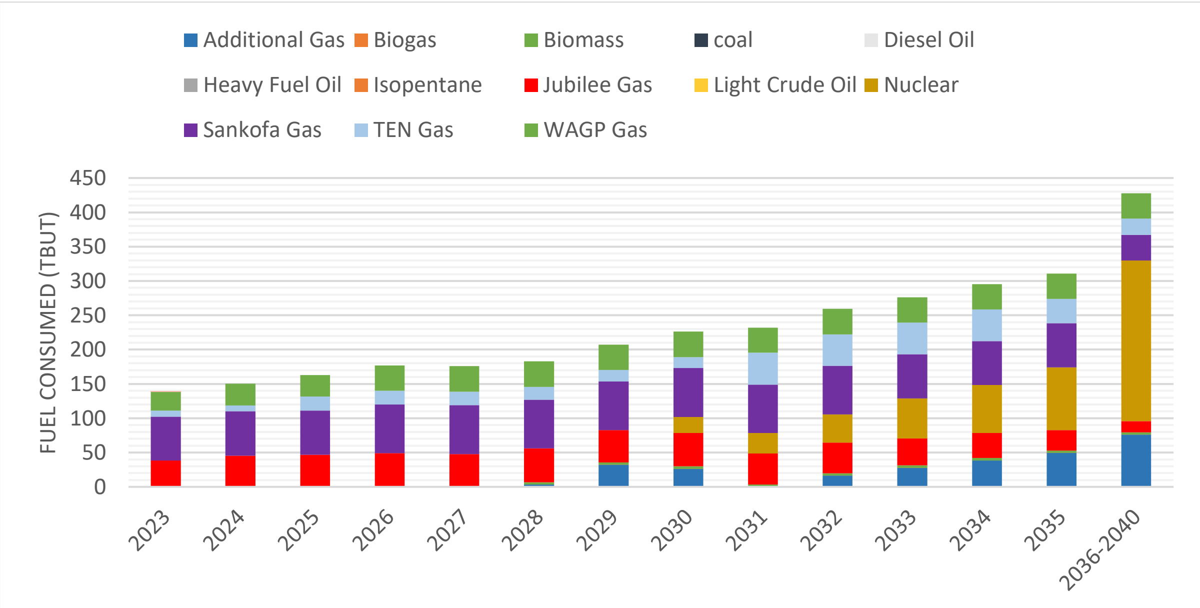


Figure 54: Fuel Consumed by Type for the Enhanced G-NDC Strategy

Under this strategy, domestic gas and import from WAGP will be sufficient for power generation until 2026 when additional import of about 9.6 TBtu is needed for power generation. As demand increases which give rise to increasing capacity additions, “Additional Gas” is only needed in very small quantities starting in 2028 (~ 3.2 TBtu) and rises to about 49 TBtu in 2035. Reductions in gas consumption can be attributed to the coming online of the 1,051 MW nuclear cumulative capacity by 2035.

Transmission Capacity

This strategy also requires some upgrades to the SouthWest to SouthEast, and the SouthWest to North transmission corridors. There are no significant differences between this strategy and the unconstrained. This is mainly due to the coming online of a nuclear plant in the SouthWest which reduces the need for transmission from the East to the West to serve local demand and other zones which relies on SouthWest.

The estimated transmission upgrades for the transmission paths are indicated in Table 39

Table 39: Transmission Upgrades Required for the Enhanced G-NDC Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy V _Reference Builds		Difference from Strategy I	
		2023-2032	2033-2037	2023-2032	2033-2037
SouthWestGH	SouthEastGH	645	2,231	-22	574
SouthWestGH	AshantiGH	-	-	-	0
SouthWestGH	NorthGH	429	350	-20	0

** positive & negative implies greater than or less than Strategy I respectively.*

6.5. Comparison of Metrics Across Strategies and Sensitivities

As mentioned in the earlier sections, the results of the capacity builds from the Reference Case assumption for each strategy (as shown in Table 30) were fixed for the entire planning period, and these results were then "tested" over the full range of sensitivities (see Table 31). So, for each strategy, there were 11 run results including the reference assumptions and a total of 66 run results for the entire strategy-sensitivity combinations. The metrics for each of the sensitivities for the Unconstrained strategy are shown in Table 40 and those of the other strategy can be found in the Appendix of this report.

Cost Metric

Results for the cost metrics (in 2016 US Dollars) for each of these strategies are presented in Figure 55 to Figure 58**.** They represent the cumulative investment costs and cumulative total system costs metrics for each of the five strategies. Figure 55 and Figure 56 show the cumulative overnight investment costs for each strategy, across the sensitivities which affect the investment cost, over the 10-year and 18-year periods, respectively. For each strategy, the average of all the sensitivities is also shown (as red dots and labelled in each figure). The average of the sensitivities is considered the most reasonable value to use for comparison across the strategies. See Table 41 for a summary of all the strategies for both 10- and 18-year periods.

The Enhanced G-NDC (Strategy V) portfolio seems to be the worst-performing strategy in terms of total investment cost for both the 10-year and the 18-year period. As expected, the total investment cost for both medium- and long-term periods for all the strategies were sensitive to high demand (see Figure 55 and Figure 56) especially for Strategy V.

For the cumulative total system cost, as presented in Figure 57 and Figure 58, the response of the various strategies under different sensitivities was more widely spread. The total system cost is most affected by the high-demand scenarios across all sensitivities. The changes in the total system cost can vary by as much as 12% to 35% depending on specific sensitivity. However, on average, over the entire planning period, the lowest cumulative total system cost is recorded by the Unconstrained Strategy with an average system cost of about $17.1 billion, which was about $55 million USD lower than the second lowest strategy which is the REMP strategy. The REMP appears to be cheaper in the shorter term (10years) primarily due to the fact that the IPM which is forward-looking, is anticipating the coming online of a large capacity of 1GW, hence the decision to stall other builds. It is therefore important to assess the strategies across the entire planning period in order to get a wholistic view of the cost for the duration.

The diversification by geography is first placed in terms of having the lowest investment cost in the long term, even with the relatively high delivered cost of gas to the 440MW CC and CT plants built in the AshantiGH. A very important point to note, however, is that the additional benefit of substantive reduction in transmission losses due to the location of this plant has not been factored in this analysis.

In conclusion, investment cost needed for capacity expansion and total system cost of generation in Ghana will be very much affected by future prices of fuel and future projection on demand. The Unconstrained Strategy appears to have the lowest cost over the 18-year period.

Other Metrics

Reliability: The two metrics under reliability are the unserved peak and the transmission congestion. Unserved peak was recorded under only the high demand sensitivity across all the strategies within the first 6 years. However, the results of this metric – which is presented as the average between 2023 to 2040, indicate the worst-performing strategy to be strategy II. Even though the difference between this one and the other strategies under this metric is not significant, Strategy V comes out as the best performing having recorded an average of about 15 MW. There was no transmission congestion across all the strategies. See Table 41.

In general, however, Strategy V is the strategy that performed well under the reliability metrics having performed relatively well under both unserved peak and transmission congestion. This essentially indicates that in a world where the build decisions from the IPSMP have been ring-fenced (apart from the demand sensitivities), Strategy VI is likely to perform relatively better under the given assumptions and constraints. See Table 41.

Table 40: Metrics for 10 Years (2023–2032) for the Unconstrained Strategy

METRIC	UNIT	Reference	High Demand	Low Demand	High Fuel Prices	Low Fuel Prices	Limited Gas Supply	Greater Gas Supply	Limited Water Inflow	High RE Cap Cost	Low RE Cap Cost	Low Conventional CapCost	AVERAGE
Total Capital Cost	***M USD***	720	1190	460	710	710	710	710	710	800	610	560	720
Total System Cost	***M USD***	11,060	14,023	10,230	11,178	9,580	11,139	10,963	10,844	11,146	10,954	10,901	11,105
Transmission Congestion	***%***	0	0	0	0	0	0	0	0	0	0	0	0
Unserved Peak	***MW***	0	334	0	0	0	0	0	0	0	0	0	33
Fast Ramp/Variable RE Capacity	***Ratio***	0	0	0	0	0	0	0	0	0	0	0	0
Local Reserve (Ashanti&North), Geographic Diversity	***%***	13%	12%	14%	13%	13%	13%	13%	13%	13%	13%	13%	13%
Local Reserve (Ashanti&North)	***%***	74%	77%	80%	74%	74%	74%	74%	74%	74%	74%	74%	75%
Air Quality (Sox, Nox)	***Thousand Tons***	94	107	91	95	96	94	94	93	94	94	94	95
GHG	***Thousand Tons***	13,068	16,509	12,030	13,028	13,075	13,053	13,075	12,943	13,068	13,068	13,068	13,291
Ash Production	***Thousand Tons***	0	0	0	0	0	0	0	0	0	0	0	0
Land requirements	***Acres***	10,442	838	642	10,442	10,442	10,442	10,442	10,442	10,442	10,442	10,442	8,501

Table 41: Average across Sensitivities for 10- and 18-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC		RESILIENCE METRIC	LOCAL ENVIRONMENT METRIC		LAND USE	CLIMATE METRIC
	Total Capital Cost	Total System Cost	Transmission Congestion	Unserved Peak	Local Reserve (Ashanti & North)	Air Quality (Sox, Nox)	Ash Production	Land requirements	GHG
	M USD	*M USD*	*%*	*MW*	*%*	*Thousand Tons*	*Thousand Tons*	*Acres*	*Thousand Tons*
Strategy I - Unconstrained	718	11105	0	33	75%	95	0	8501	13291
Strategy II - Diversify with Nuclear	973	11276	0	34	72%	92	0	8173	12813
Strategy III - Diversify Geographically	711	11233	0	33	82%	95	0	8452	13352
Strategy IV - REMP	916	11134	0	33	76%	93	0	11952	12912
Strategy V - Enhanced G-NDC	1512	11565	0	27	77%	82	0	19973	12144
2023-2040									
Strategy I - Unconstrained	1918	17090	0	19	69%	97	0	7512	15737
Strategy II - Diversify with Nuclear	2818	17696	0	19	66%	92	0	6902	14306
Strategy III - Diversify Geographically	1907	17324	0	19	78%	99	0	7500	15850
Strategy IV - REMP	2229	17145	0	19	71%	94	0	9411	15264
Strategy V - Enhanced G-NDC	3879	18328	0	15	72%	81	0	13884	13042

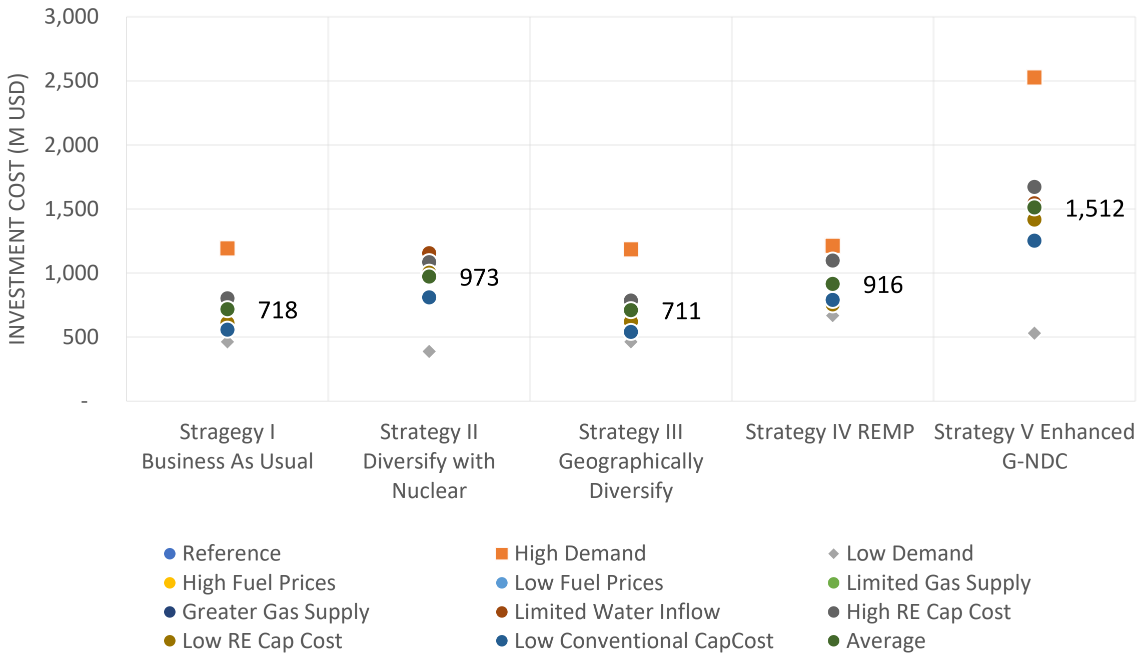


Figure 55: Total Investment Cost Metric across sensitivities for 10-Year Planning Horizon

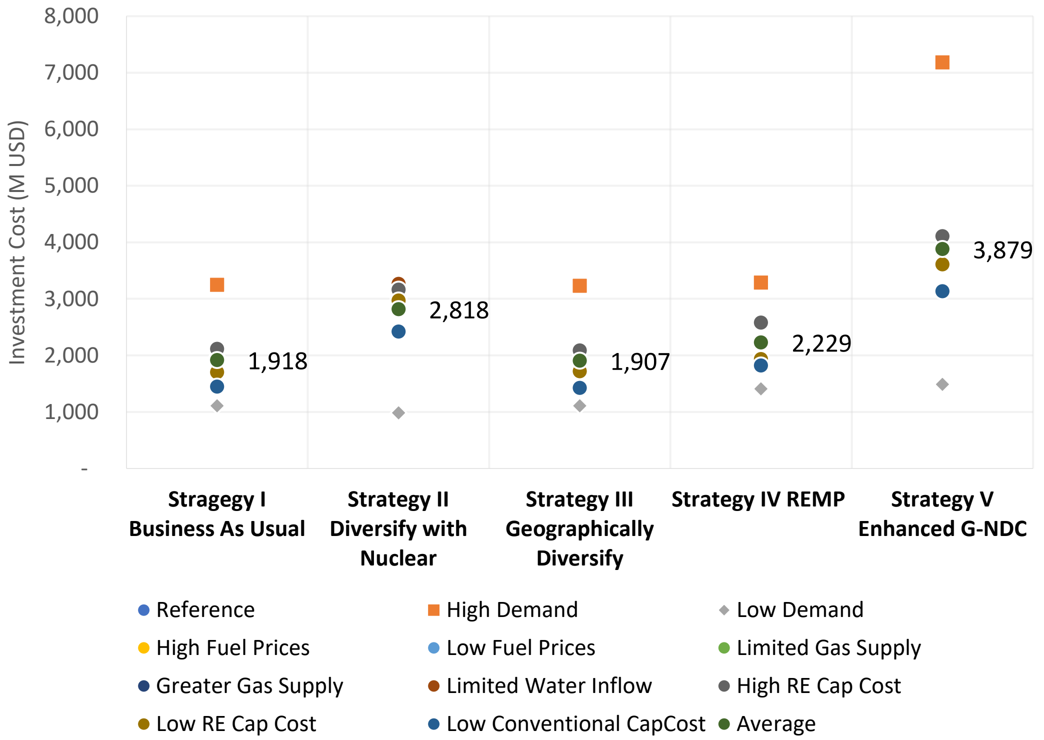


Figure 56: Total Investment Cost Metric across sensitivities for 19-Year Planning Horizon

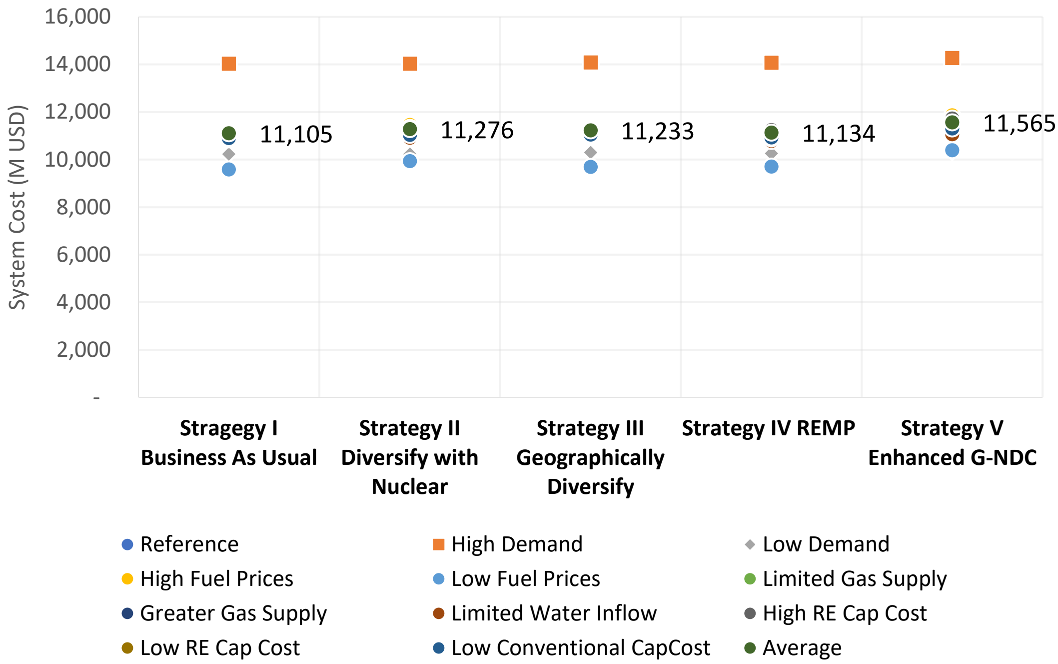


Figure 57: Total System Cost Metric across sensitivities for 10-Year Planning Horizon

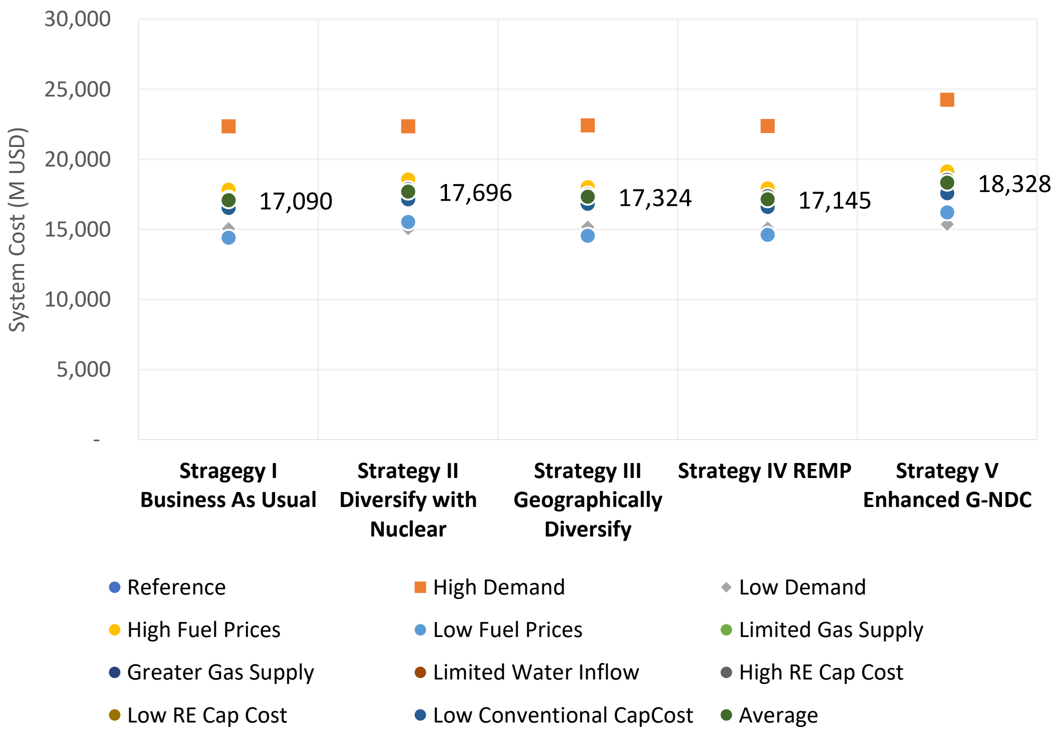


Figure 58: Total System Cost Metric across sensitivities for 20-Year Planning Horizon

Resilience: For the broader theme of resilience, the metric identified here is the local reserve capacity (for the Ashanti and NorthGH zones). Over the 18-year period, Strategy III (Geographically Diversified Strategy), performs very well under the local reserve metric being the strategy with the highest share of generation in the NEDCo and Middlebelt areas in both the 10-year and 18-year period recording about 78%.

Local environmental metric: The best-performing strategy under the local environmental metric is Strategy V (Enhanced G-NDC Strategy) in both the 10-year and the 18-year period due to the greater renewable energy mix and nuclear in the build portfolio.

Land use metric: This metric is nearly similar across all of the strategies except for Strategy V, which performs poorly due to the construction of two small hydro plants. However, Strategy II has the least footprint per MW of capacity addition largely due to the nuclear plant constructed in the last 2020s.

Climate metric: The Enhanced G-NDC, as its name implies, performs the best under the climate metric due to the low emissions recorded for this strategy across all the sensitivities with a recorded average of about 13,042 tonnes over the 18-year period.

6.6. LEAST-REGRETS PORTFOLIO

First, each of the metrics was linearly ranked on a numeric scale from 0 to 10, wherein the strategy with the best value was assigned a zero rank and the strategy with the worst value assigned a 10. The rankings of the strategies are in Table 42 and Table 44, which show the ranking for the various strategies across all the metrics for the 10- and 18-year period respectively. Each of these metrics was further simplified into combined rankings for cost, reliability, resilience, and environmental performance.

Colour Ranking Linear Scale (0-10)				
0-2 (Best)	2-4	4-6	6-8	8-10 (Worst)
⬆	↗	➡	↘	⬇

These rankings are then converted to symbols indicating how good (or bad or neutral) the strategy is rated for each metric. These symbols facilitate a quick visual analysis of the strategy for each metric and the combination of metrics. See Table 43.

Similar ratings and rankings were conducted for each strategy for both the 10- and 19-year time period using the average of the respective metrics across all the sensitivities—see Table 42 to Table 45.

The analysis shows that the **Diversify Geographically (Strategy III)** is more resilient and conforms to government policy of diversifying geographically generation capacity, and it also performs relatively well under all the other metrics for the whole 18-year planning period except the cost metric where the Unconstrained Strategy (Strategy I) performs better. **Hence, the Diversify Geographically Strategy is deemed as the most favourably ranked strategy and therefore it qualifies as the *Least-Regrets* Strategy for the 2023 IPSMP update**. The strategy is largely characterized by development of renewables and combined cycle plants, with some considerable level of transmission upgrades as shown in Figure 59.

The implications of selecting this portfolio are:

- Relatively more renewable energy plants are required over the 10-years, compared to thermal generation.

- The required investment cost is low due to the assumed declining cost of solar and wind, and the fact that this strategy utilizes the existing natural gas plants as the electricity demand increases.
- Natural gas is the primary conventional fuel used in this strategy, and if the cost of natural gas is lower than what is assumed, then the total system cost of this strategy will be considerably lower than what is shown in the current analysis.
- New gas fields already in the exploration/or development phase should come online by 2028 to support the growing demand for natural gas in the power sector.
- This strategy has relatively low CO_2 emissions and is consistent with Ghana's climate change commitments.
- Additional studies will have to be conducted to ensure the capacity of variable renewables in this study can be evacuated into the transmission system—see Appendix for studies conducted on grid integration of renewables in Ghana.
- When new more-efficient conventional plants are built and some of the existing capacity is retired, the capacity factor of existing plants will go down. If for contractual reasons, the less-efficient existing plants are forced to run with higher capacity factors, then the total system cost will increase, potentially resulting in higher tariffs.
- As new capacity is added in the NEDCo area, overall transmission losses for GRIDCo will decrease.
- In this strategy, there is still relatively limited new generation capacity in the Middlebelt region of Ghana, since it is more cost-effective to transmit power from neighbouring zones. Solar PV plants are only built in this zone in the later years.

Table 42: Ranking of the Strategies for 10-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC		RESILIENCE METRIC	LOCAL ENVIRONMENT METRIC		LAND USE	CLIMATE METRIC
	Total Capital Cost	Total System Cost	Transmission Congestion	Unserved Peak	Local Reserve (Ashanti & North)	Air Quality (Sox, Nox)	Ash Production	Land requirements	GHG
Strategy I - Unconstrained	0.1	0.0	0.0	9.8	7.7	9.9	0.0	0.3	9.5
Strategy II - Diversify with Nuclear	3.3	3.7	0.0	10.0	10.0	7.4	0.0	0.0	5.5
Strategy III - Diversify Geographically	0.0	2.8	0.0	10.0	0.0	10.0	0.0	0.2	10.0
Strategy IV - REMP	2.6	0.6	0.0	10.0	6.0	8.2	0.0	3.2	6.4
Strategy V - Enhanced G-NDC	10.0	10.0	0.0	0.0	5.5	0.0	0.0	10.0	0.0

Table 43: Combined Metrics Ranking of the Strategies for the 10-Year Planning Period

	Cost Metric	Reliability Metric	Resilience Metric	Local Environment Metric	Land Use Metric	Climate Metric
Business As Usual Strategy I	0.0	9.8	7.7	9.9	0.3	9.5
Diversify with Nuclear Strategy II	3.5	10.0	10.0	7.4	0.0	5.5
Diversify Geographically Strategy III	1.4	10.0	0.0	10.0	0.2	10.0
REMP Strategy IV	1.5	10.0	6.0	8.2	3.2	6.4
Enhanced G-NDC Strategy V	10.0	0.0	5.5	0.0	10.0	0.0

Table 44: Ranking of the Strategies for 18-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC		RESILIENCE METRIC	LOCAL ENVIRONMENT METRIC		LAND USE	CLIMATE METRIC
	Total Capital Cost	Total System Cost	Transmission Congestion	Unserved Peak	Local Reserve (Ashanti & North)	Air Quality (Sox, Nox)	Ash Production	Land requirements	GHG
Strategy I - Unconstrained	0.1	0.0	0.0	9.8	7.4	8.8	0.0	0.9	9.6
Strategy II - Diversify with Nuclear	4.6	4.9	0.0	10.0	10.0	6.1	0.0	0.0	4.5
Strategy III - Diversify Geographically	0.0	1.9	0.0	10.0	0.0	10.0	0.0	0.9	10.0
Strategy IV - REMP	1.6	0.4	0.0	10.0	5.7	7.3	0.0	3.6	7.9
Strategy V - Enhanced G-NDC	10.0	10.0	0.0	0.0	5.3	0.0	0.0	10.0	0.0

Table 45: Combined Metrics Ranking of Strategies over 18-year Planning Period

	Cost Metric	Reliability Metric	Resilience Metric	Local Environment Metric	Land Use Metric	Climate Metric
Business As Usual Strategy I	0.0	9.8	7.4	8.8	0.9	9.6
Diversify with Nuclear Strategy II	4.7	10.0	10.0	6.1	0.0	4.5
Diversify Geographically Strategy III	0.9	10.0	0.0	10.0	0.9	10.0
REMP Strategy IV	1.0	10.0	5.7	7.3	3.6	7.9
Enhanced G-NDC Strategy V	10.0	0.0	5.3	0.0	10.0	0.0

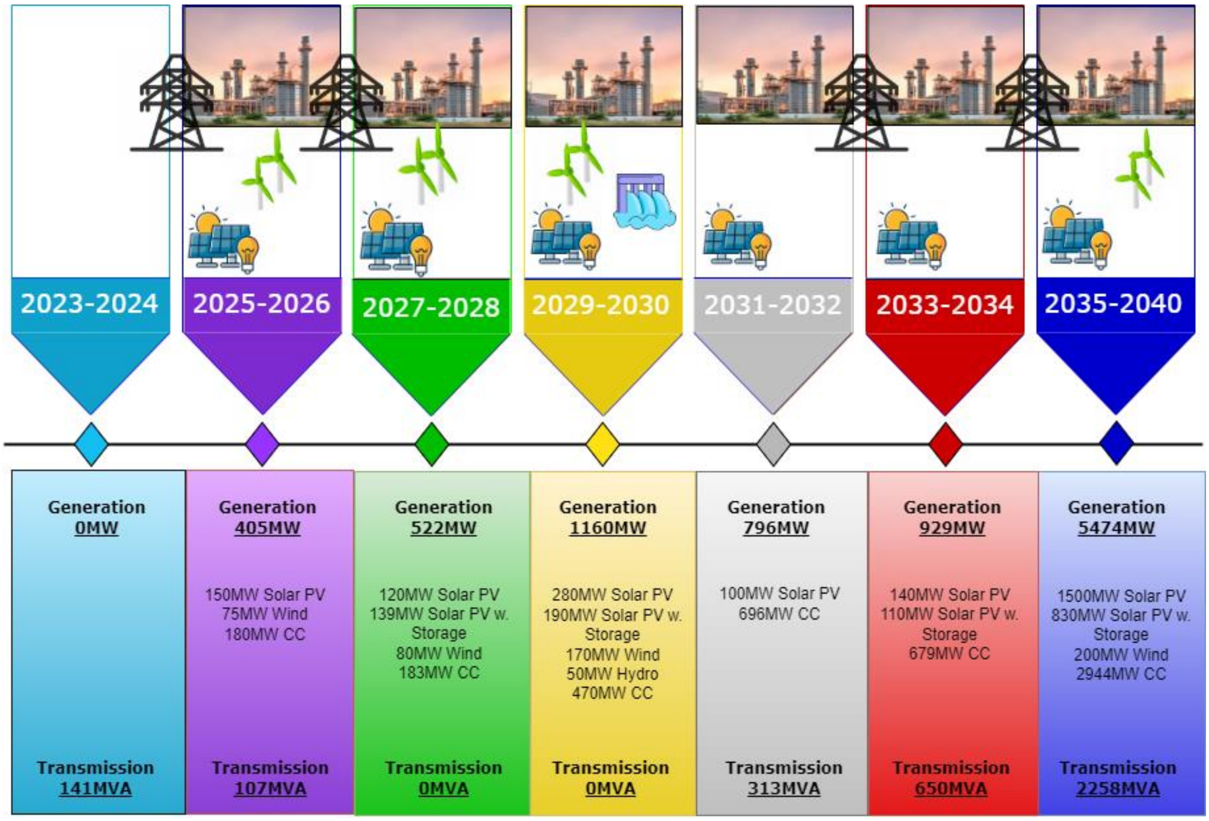


Figure 59: Least-Regrets Build Plan

The Least Regrets Portfolio discussed above is optimised under the reference demand assumptions, and all of the other reference assumptions discussed in Chapter 5 and Section 6.4.1.

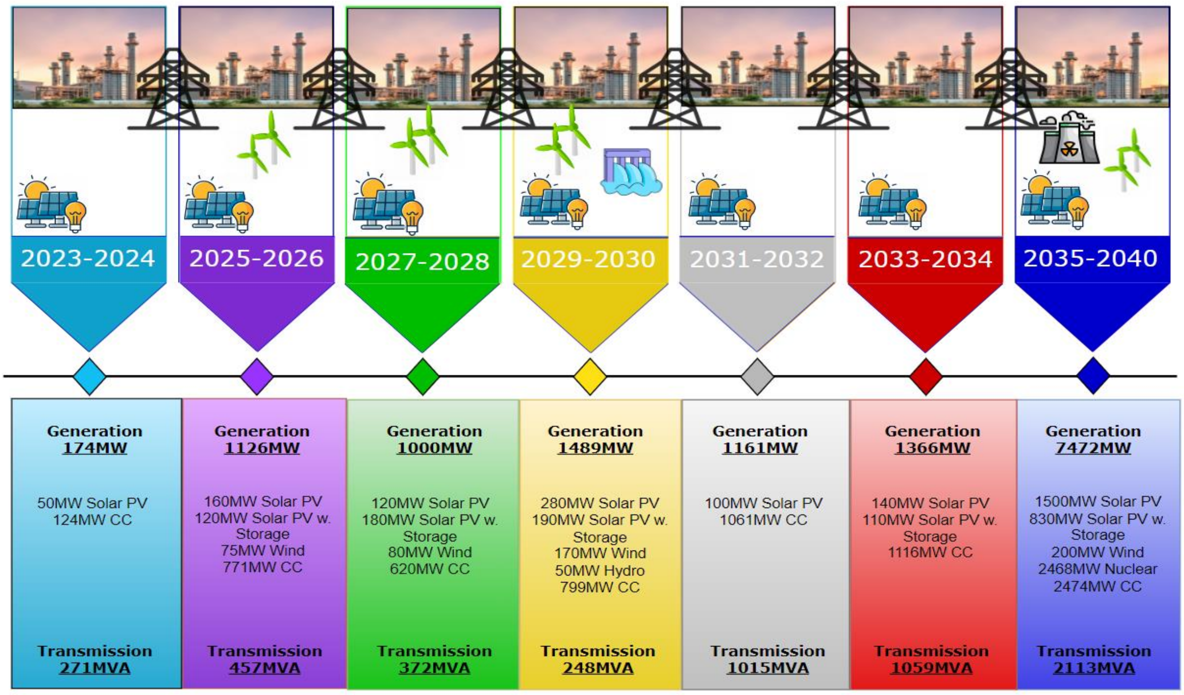


Figure 60: Least Regrets Build Plan Under High Demand

However, it is also important to consider how the build profile might change if the model was optimized using the High Electricity Demand case (see Figure 15 in Section 5.3.3). The results of the Least Regrets strategy optimized under the High Demand case are shown in Figure 60.

A comparison of Figure 59 and Figure 60 shows an additional 1,529 MW of CC capacity is necessary in 2023-2032 under the high demand case, relative to the reference case demand.

Not surprisingly, beyond the 10-year timeframe, significantly larger number of new plants are needed to meet the High Demand case than the Reference Demand case.

6.6.1. Gas Demand in the Least Regret Strategy

Reference Electricity Demand Case

With increasing electricity demand, the demand for natural gas from power plants in both the Takoradi and Tema enclaves increase gradually from 2023 through to the end of the planning period. See Figure 61.

The annual average demand for gas for power plants in Takoradi rises from 184 MMcfd in 2023 to about 244 MMcfd by 2025. By 2030, gas demand reaches about 249 MMcfd. The gas demand in Tema enclave is expected to be about 145 MMcfd in 2023 and it rises to about 260 MMcfd by 2030. A significant portion of the gas supply in the Tema enclave comes from the reverse flow. The completion of the gas pipelines to Anwomaso in Kumasi will make gas available to power plants. Average gas demand in Kumasi is expected to rise from 53 mmscd in 2023 to 120 mmscfd by 2032. 'Additional gas' which is expected new domestic gas production is needed by 2028, due to increasing electricity demand and diminishing gas production from the Jubilee field.

The total gas demand in Ghana continues to rise from about 381 MMcfd in 2023 to 702 MMcfd in 2032 and 986 MMcfd in 2040. This demand is met by new gas supply from domestic gas production and N-Gas under reference electricity demand.

High Electricity Demand Case

Under a high electricity demand case, the total gas demand in Ghana rises from 427 MMcfd in 2023 to 915 MMcfd in 2032 and 1,678 MMcfd in 2040. If the electricity demand is very high (as discussed in Figure 15 and in Chapter 5.3.3), then gas demand in both Tema and Takoradi continues to rise over time until 2040 when nuclear comes online. Takoradi demand is about 71% of total demand in 2032 which reduces to 62% in 2040 due to increase gas consumption in Ashanti. See Figure 61.

Higher power demand means greater demand for natural gas. Therefore, far larger volumes of additional domestic gas is needed, and it could be needed as early as 2028. This increased need for gas is indicated by the utilization of LNG in the SouthEast as early as 2026. The LNG volumes shown here in the model can serve as a proxy for additional supply from WAGP or additional domestic gas.

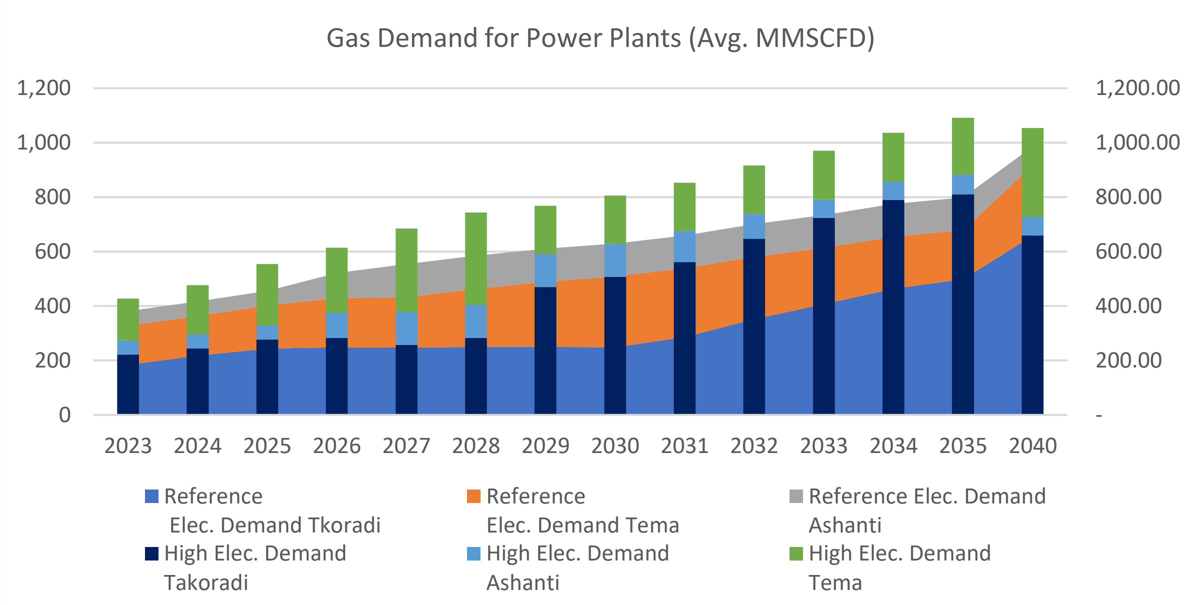


Figure 61: Gas Demand for Least Regret Strategy under Reference and High Electricity Demand Cases

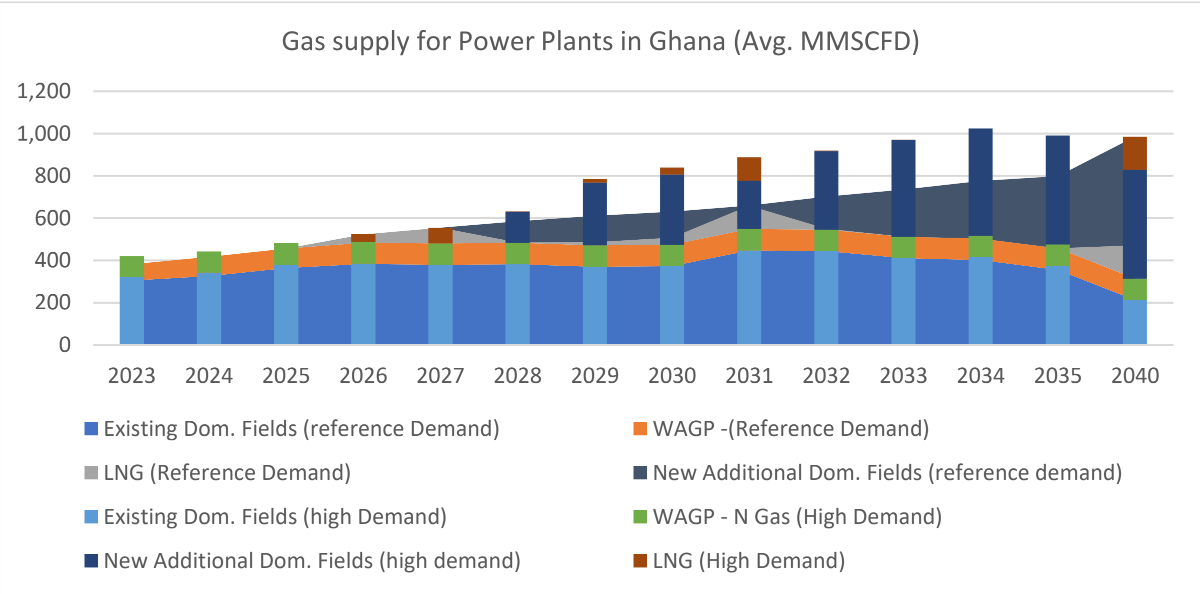


Figure 62: Gas Supply for Least Regret Strategy under Reference and High Electricity Demand Cases

6.6.2. Variable Renewable Energy in the Least Regret Strategy

The amount of variable renewable energy (vRE) capacity that comes online, as shown in the least regrets strategy (Figure 59), is driven by two factors: a) the capital costs of the solar and wind plants; and b) the marginal cost of natural gas delivered to Ghana's conventional power plants.

The marginal cost of delivered gas determines the marginal cost of power generated from conventional plants (both existing and new). As such, if the annualized capital and FOM costs from new solar PV or wind power plants fall below the generation cost (i.e., VOM + fuel cost) of the marginal plants, then electricity generated from solar PV or wind power plants is more cost competitive than the electricity generated from existing natural gas plants, irrespective of any capacity charges. The marginal costs of electricity from these conventional plants would be even higher (i.e., less cost competitive) if these plants were to use fuel oil, instead of gas.

Therefore, there is a clear interplay between declining trends of capital cost of solar PV and wind power plants and the marginal cost of natural gas delivered to conventional power plants.

If the marginal cost of the delivered natural gas is high, this then presents a greater opportunity for vRE capacity to come into the generation system on a purely economic basis, especially if the capital cost of the vRE technologies is also low. On the other hand, if the cost of gas is low and/or capital cost of vRE is high, then very little (or no) opportunity exists for vRE builds, because the marginal cost of generation from conventional plants is lower than the total cost of the vRE.

However, the pricing of the cost of natural gas delivered to power plants is highly dynamic, often driven by government and regional policies—e.g., amount of taxes enforced on natural gas production, cost of transportation and gas processing, contractual terms of regasified LNG, etc. In addition, it is important to also factor how the vRE are procured which will go a long way to determine at what price it comes in and give vRE a chance to compete with natural gas plants. The key is to bring in utility-scale solar and wind lower than nominal 8.5 UScents/kWh and 9 UScents/kWh.

Therefore, with all the uncertainty on the cost of natural gas supply to power plants and the price of vRE that will be procured in the future, it is critical to consider various scenarios and regularly update the expected future gas production volumes, gas prices, contractual obligations, as well as the cost of vRE technologies. Such updates should inform the specific RE build plans over time, and it should not pose challenges for vRE deployment, as these vRE technologies can be constructed rather quickly (1-2 years) if there is a well-defined procurement process.

6.6.3. Timeline for Procurement

The least regret portfolio shown above highlights when specific power plants and transmission resources need to come online to meet the growing demand in Ghana. However, to effectively guide the procurement of these new resources, it is important to understand the timelines associated with the various processes necessary to ensure the development of these assets.

Table 46 gives a general estimate of the development process for procuring different types of power plants and transmission infrastructure. The process has been divided into three broad components: a) procurement stage, b) financial close, and c) construction period. Although estimates under these three stages may vary or change for a specific project on a case-by-case basis, they are good estimates which can be used to guide the future procurement process of new power assets in Ghana.

The procurement stage is the time needed for a competitive RFP process to be initiated and concluded, as described in the Recommended Framework for Future Procurement chapter below. Once a bidder is selected then they have to conclude the financing for the project with financiers, which is the time required in the Financial Close phase. Once financial close has been achieved, the construction phase can begin.

Table 46: Estimated Timeline for the Development of Various Types of Generation and Transmission Resources

Technology	Procurement	Financial Close	Construction	Total Time
Solar PV	6 - 12 months	6 - 12 months	9 - 18 months	2 – 4 years
Wind	6 - 12 months	6 - 12 months	15 - 24 months	2.5 – 4 years
Combined Cycle	6 - 18 months	6 - 12 months	30 – 36 months	4 – 6 years
Small Hydro Power	12 – 18 months	6 – 12 months	3 – 4 years	5 – 7 years
Nuclear Power	Subject to NRA approval	12 - 36 months	6 – 7 years	7 – 10 years following NRA approval
Transmission	6 – 12 months	6 – 12 months	9 – 24 months	2 – 4 years

7. KEY FINDINGS AND RECOMMENDATIONS

7.1. KEY FINDINGS

7.1.1. Generation and Demand

1. There is enough capacity (4,763 MW) to meet both demand at peak and the planned reserve margin of 18% for 2023 (4,328 MW) and 2024 (4,547 MW). See Figure 62.
2. Considering existing capacity as of the first quarter of 2023 (Ameri relocation inclusive), additional conventional, thermal generation will not be needed until 2026. See Figure 62.
3. Diversify Geographically Strategy, which considered all the assumptions in the Unconstrained Strategy (reference Case assumptions on demand, technology costs, gas resource availability, TTCs, build 50MW small hydro and 150 MW CC) and diversify by building additional 180 MW combined cycle plant in Ashanti by 2027 and 250 MW in SouthEast-GH by 2029 is the ***Least-Regrets*** Strategy. This is primarily because it is more resilient and coincidentally conforms to government policy of geographically diversifying Ghana's generation enclaves. In this strategy, solar photovoltaics (PV) and wind power plants are integrated into the grid gradually over time, and additional combined cycle capacity is needed to be built beyond the 2020s.

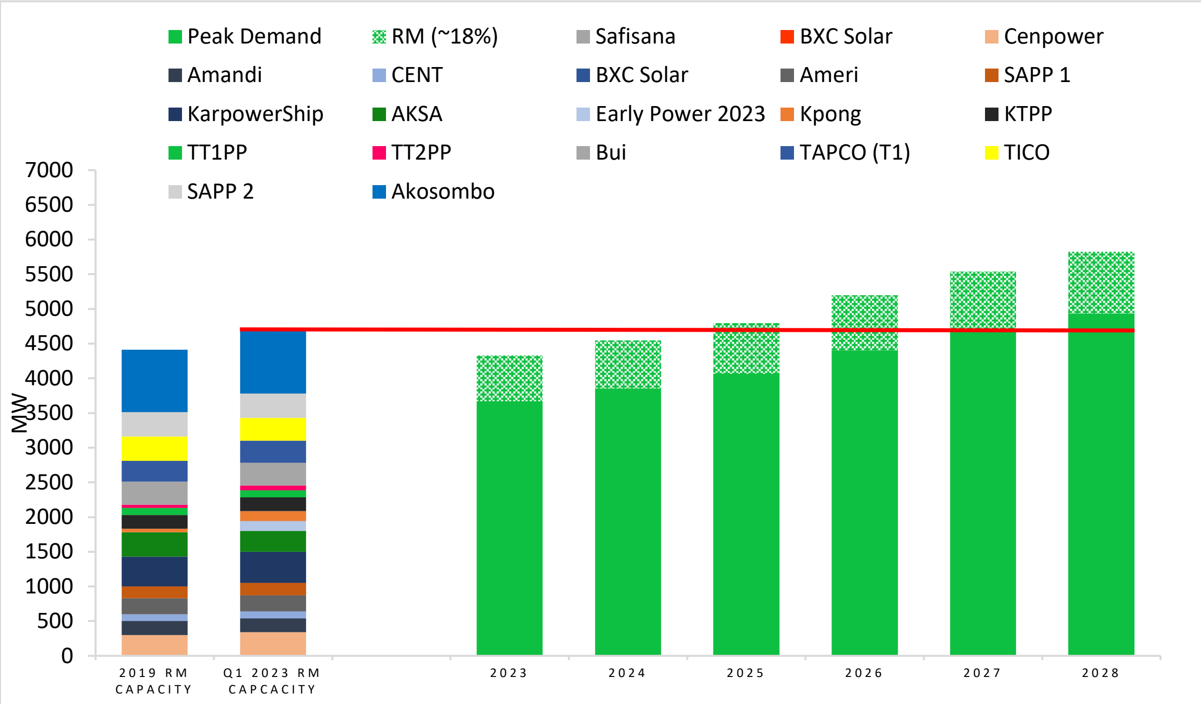


Figure 63a: Medium-Term Supply-Demand Balance for Reference Electricity Demand

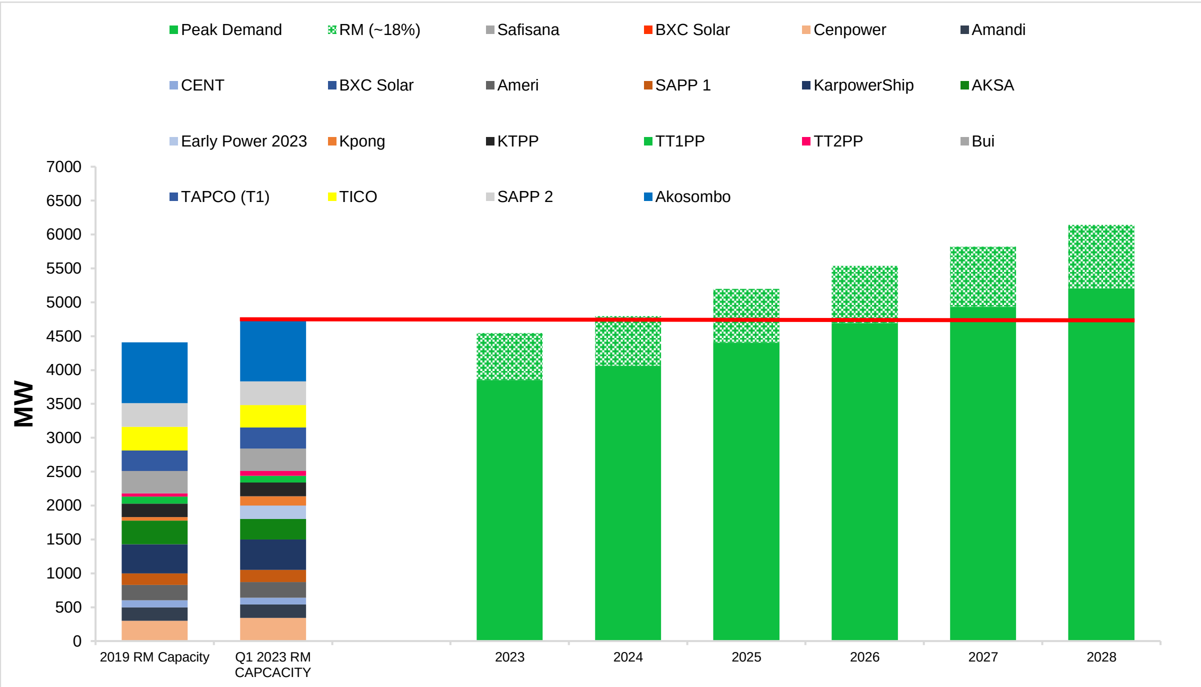


Figure 64b: Medium-Term Supply-Demand Balance for High Electricity Demand

4. Over the next 10 years (2023–2032), based on the Least-Regrets Strategy under the Reference Case demand projection, a cumulative sum of about 1,485 MW of renewable energy (solar PV, wind, Solar PV with Storage, and small hydropower) and combined cycle capacity of about 1,490 MW will be needed.

- The builds for renewables and conventional thermal plants for the next 10 years and the following 7 years for the Least-Regrets strategy are shown in Table 47. The Least-Regrets strategy has significant renewable builds in the near term because the generation costs from existing power plants rise over time, however as more gas resources come into play, more conventional plants are built in the longer term. This is the same under the High Demand Case.

Table 47: Unplanned Builds in MW for Least-Regrets Strategy

Unplanned Builds (MW)	Reference Demand Case	
	2023 Least-Regrets	
	2023–2032	2033–2040
Renewable	1,354	2,780
Conventional Thermal	1,529	3,623
Unplanned Builds (MW)	High Demand Case	
	2023 Least-Regrets	
	2023–2032	2033–2040
Renewable	1,545	2,780
Conventional Thermal	3,375	3,590
Nuclear		2,468

5. Demand growth is the major factor that determines how much new capacity is needed in the future. Therefore, a focused effort to better understand what the underlying factors are that determine demand growth (e.g., temperature-dependency, price-elasticity, granularity of sectoral and regional economic growth rates) is necessary for developing better assumptions and more sophisticated models for demand forecasting.

   Generally, utilities tend to project high demand growth based on over-projected demand from customers. High demand projections also encourage the development of new power generation capacity. However, there are a number of other factors (perception of reliability of grid-based electricity, higher consumer tariffs, energy efficiency, declining costs of captive generation with low oil prices, and dramatic reductions in solar PV technologies, etc.) that weaken the elasticity of electricity growth and economic growth—not only in Ghana but also globally.

7.1.2. Renewable Energy

6. The modelling results indicate that solar PV and wind capacity (as well as biomass, waste-to-energy, small hydropower, etc.) need to come online in 2025, even without any renewable energy target.
7. New solar PV and wind power plants need to be economically competitive with natural gas-based power plants in the long run. Therefore, the economics of renewable energy technologies (this applies to nuclear as well) is affected by the delivered cost of natural

gas. The capital cost of new solar PV and wind plants should be low enough to displace the marginal cost of generation from oil or gas-based power plants.

- Low-cost Supply from renewable energy sources (i.e., solar PV comes in at flat nominal 8.5 USc/kWh and wind at flat nominal 9.0 USc/kWh) are still economic even under the lower gas prices

8. Despite the current over-capacity up to 2024, developing and installing competitively priced solar PV capacity in the range of 20-50 MW is consistent with the Least-Regrets strategy and could result in lower end-user tariffs in the long term.
9. Additional studies are, however, needed to fully assess the impact of grid integration of renewables, including the need for ancillary services, in light of policy goals and the expected cost decline of specific technologies.
10. Small hydropower plants are very useful renewable energy components in the generation mix mainly because their outputs can be predicted, which makes them dispatchable. However, they tend to raise the overall system cost of energy due to their higher capital costs. The Least-Regrets Resource Plan includes one small hydropower plant in the NEDCo region as a committed power plant to reflect government's plan. The Pwalugu Multi-purpose dam has additional benefits such as irrigation and flood control.
11. Land requirements for solar PV generation is far less than that for small hydropower systems due to (i) the associated inundation of large tracks of land (as a retaining dam is sometimes needed), (ii) displacement of settlements, and (iii) other environmental issues such as loss of flora and fauna and methane emissions resulting from submerged vegetation. However, in the case of solar PV installations, one can still utilise the land area beneath or beside the panels for various uses depending on the design of the mounting structures. Also, the surface area of the dam can be utilised through the deployment of floating solar.

7.1.3. **Conventional Power Plants**

12. Conventional thermal power plants can be based on natural gas, coal, or nuclear power plants. However, these generation technologies tend to displace each other, meaning that if all of the thermal capacity shown in Table 47 is based on natural gas, then additional nuclear plants should not be built. Similarly, if significant nuclear capacity is firmly planned to be built by the early 2030s, then gas capacity should not be built (or significantly reduced).

- Increased growth in electricity demand well beyond what is assumed in the Reference demand case is needed for large number of new conventional power plants.
- If the price of domestic gas is reduced, and if there is sufficient availability of domestic gas or low-priced LNG, then gas-based plants are more favourable.
- Nuclear plants are generally more expensive to build than other thermal power plants, and nuclear plants require greater regulatory oversight. However, nuclear plants do have lower operational and fuel costs.

- Nuclear power plant is uneconomic under current gas supply projections and reference electricity demand. However, nuclear becomes attractive under high gas price, high demand, limited gas supply or emission constraint scenarios.

7.1.4. **Transmission**

13. The Middlebelt and NEDCo areas are particularly dependent on power supply through transmission from the Southeast and the Southwest.
    - Hence, additional transmission builds and/or new local generation capacity is needed to improve grid stability and reliability, particularly during transmission contingency conditions. Therefore, plans to develop generation enclave in the middle belt should be expedited.
    - Expanding transmission capacity lowers overall system cost, and allows for greater export opportunities to Burkina Faso and Mali.

7.1.5. **Fuel Supply**

14. The construction of gas pipelines to Kumasi for power generation will improve availability of fuel to thermal plants in the middle belt.
    - If demand in the northern belt and export to Mali-Burkina markets continue to grow, then the extension of the gas pipeline from the middle belt to the northern belt, in the long term, will also improve reliability and reduce losses.
15. Gas supply estimates indicate that there will be insufficient gas to meet demand for power generation beyond 2025.
16. Additional domestic gas is projected to come in 2028 and supply of gas from LNG is scheduled to commence at the end of 2024.
17. Further assessment of the gas supply situation needs to be carried out in light of new additional domestic production before any determination for long-term LNG contracts.
18. The LNG regasification and storage terminal in Tema is a strategic infrastructure to increase gas supply security, in case of domestic gas interruptions (due to maintenance or unplanned outages). However, gas delivered from such an LNG terminal will have higher gas prices—which might be reasonable as long as the high-priced supply does not persist for a long time over any given year.

7.2. Recommendations for Implementation

7.2.1. **Demand**

1. Support and implement policies and programmes that support the deployment of energy efficiency measures to reduce waste.

– There is great potential for the implementation of energy efficiency and conservation measures in the country.
  The use of light-emitting diode (LED) lamps, more efficient air conditioners and fridges/deep freezers can decrease electricity consumption and the growth rate of

electricity demand, keep carbon footprints down, and help businesses and homes to save money just as the CFL exchange programme carried out in 2007. Which saved the country about 124 MW.

2. The Public Utilities Regulatory Commission (PURC) and the EC should facilitate and support distribution utilities to implement energy efficiency programmes that are revenue neutral.
3. The Energy Commission through Parliament has included 19 new appliances to the standard and Labelling program. These appliances include rice cookers, television sets and electric kettles. Therefore, it is recommended that all electrical appliances and equipment have a minimum energy efficiency performance standard requirement.
4. The need to determine the "true demand" for Ghana, which is inclusive of suppressed load, is very critical for any planning initiative. Furthermore, the importance of price sensitivity of sales and data collection problems, impact of energy efficiency among others, should be considered in future analysis.

7.2.2. **Generation**

5. The 175 MW AKSA power plant, to which PPA has been signed with the off-taker, ECG, and is expected to come online in 2025 should be used to fill the 150 MW additional capacity required in 2026 in the Ashanti model region.
6. All necessary action including procurement should be expedited on the 75 MW wind capacity which is required to come online in 2025.
7. Considering the time for procurement, design, construction and commissioning of power plants, the procurement of all additional capacities required in 2028 should be initiated now.
8. To ensure generation adequacy, the proposed capacity addition timelines in this IPSMP should be adhered to accordingly.

7.2.3. **Transmission**

9. Findings from the IRRP Transmission system assessment indicate the need to reinforce some sections of the grid. Furthermore, due to changes in model assumptions behind the 2011 Transmission Master Plan, there is a need for an updated version of the Transmission System Master Plan.
10. Adopt a double-circuit high-voltage transmission line configurations policy to address future right-of-way (ROW) constraints in all new high-voltage transmission and sub-transmission lines.
    - Where there is financial constraint, only one of the double-circuit would be strung until the stringing of the second circuit becomes necessitated by load growth.
    - Although this may result in slightly higher initial cost, the double-circuiting would reduce the overall cost of transmission expansions in the long run. It will also result in savings in land space and the resultant compensation payments for the grid operator.

11. Expedite plans to close the 330 kV transmission triangular loop connecting Tema, Aboadze and Kumasi to address current transmission reliability constraints. Similarly, the 330 kV line from Kumasi to Bolgatanga should be expedited to allow an increase in the TTCs to supply the Middlebelt and the NEDCo areas.
12. Give more attention to the proposed project to close the eastern corridor loop from Kpandu-Kadjebi to Yendi through Juale (with or without the Juale hydropower plant) for increased reliability and loss reduction.
13. With the construction of the 330 kV/34.5 kV Pokuase substation, there is a need to expedite the construction of adjoining sub-transmission networks in order to optimize the evacuation of power from the station.
    - Construction of the A4BSP will reduce the losses and the high loading on the 161 kV lines within the Tema (Volta substation) to Accra (Achimota and Mallam substations) corridor.
    - Additionally, some of the loads on the highly loaded power transformers at the existing three Accra bulk supply substations (Achimota, Mallam, and A3BSP) will get transferred to the 330 kV/34.5 kV transformers at the new A4BSP.
14. Carry out an assessment of the aggregate effect of all variable renewable energy (wind and solar) connected to the grid, in addition to the individual grid impact studies of various solar and wind plants on a project-by-project basis (as currently being done by GRIDCo).
    - A study on the aggregate impact will provide an indication of the required mitigation measures as well as the cumulative effect on system losses due to changes in power flows on the various transmission lines, particularly the lines carrying power to NEDCo. Similarly, cumulative impacts of both solar and wind plants in the eastern part of the Nationally Interconnected Transmission System (NITS) should be assessed in such a study.
15. Arrange to procure and install weather forecasting stations at the GRIDCo System Control Centre and GRIDCo substations, as well as at various proposed and under-construction renewable energy plant sites.
    - Adequate SCADA communication network between the RE plants and System Control Centre will be required for accessing data from the weather systems that will help in predicting the output of the various renewable energy connected to the grid and assist the System Operator in the overall dispatch process.

7.2.4. Distribution Planning

16. Utilise information gathered from smart meters and automatic meter readers (AMR) to implement options to reduce commercial losses and improve the collection rate of distribution companies. Analyses of the data will also provide the most recent data from these customers for future demand forecasting.
17. There is a need for improved coordination between the Ministry of Energy and the distribution utilities in the extension of the grid to new communities and the connection of new customers.

– This will capture all new customers connected to the distribution network for proper metering arrangements and customer care.

18. Improve inventory management of meters to avoid the situation where some customers are put on flat rates.
19. The Energy Commission should consider reviewing relevant sections of the GRID Code to enable the use of higher voltages e.g., 69 kV instead of 33 kV for sub-transmission lines to reduce technical losses.

– Operating at higher voltages becomes increasingly necessary with high load intensities (especially in towns and cities) to reduce sub-transmission and distribution losses. Combining SCADA or other monitoring devices with the use of GIS applications can also provide information on the network in terms of overloading on distribution lines and distribution transformers, thereby helping to keep losses low.

20. Expand the scope of 2017 ECG's Accra Reliability Assessment study to cover more regional capitals and other ECG service areas to improve distribution planning.
21. NEDCo needs to expand the scope of load flow analyses carried out in Tamale (2016) to include heavy load centres like Sunyani, Techiman, Wa, Bolgatanga and other towns and cities to improve distribution planning.
22. Develop an integrated SCADA system across all utilities in Ghana.

– An integrated SCADA system will help ECG improve the distribution network monitoring thereby reducing outage times and times for restoration.

– The potential of a SCADA system for NEDCo should be carried out, with an initial pilot in Tamale, to assess improvement in monitoring of its distribution network to reduce outage durations (NEDCo currently has no SCADA or distribution automation systems (DAS)).

23. The deployment, operation and maintenance of solar PVs at the 33-kV and 11-kV voltage levels should be undertaken by the DISCo. However, GRIDCo should be informed or notified of planning, construction, operation and maintenance stages since each stage has impact on the NITS and dispatch decisions. Large (>20 MW) solar projects should be connected to the transmission grid at higher voltages.
24. Distribution utilities should carry out studies to determine localities where the installation of rooftop solar PVs can result in significant reduction of technical losses.

– This could be one of the non-wires alternatives in addressing low voltages and high losses and even grid extensions.

25. Distribution utilities should harmonize GIS data collection and its use for planning, operations, and maintenance of distribution service assets, in order to save costs and avoid duplication of effort.

7.3. OTHER ISSUES

Emission Control

26. The Commission, in conjunction with EPA, should consider including the installation of low NO_x burners to limit emissions in the specifications for all new thermal power plants.

Financing

27. Government should ensure a friendly investment environment by reducing the perceived risks to encourage sustainable private investment in the country's power sector. This will minimize the demand for a put-call-option agreement (PCOA) or any other form of guarantee/government support.

ENERGY COMMISSION