USAID
FROM THE AMERICAN PEOPLE

REPUBLIC OF GHANA

Integrated Power System Master Plan for Ghana

Volume #2
Main Report (2019 Update)

November 2019

ICF

ENERGY COMMISSION

FOREWORD

The 2019 Ghana Integrated Power Sector Master Plan (IPSMP) is an output of three years of work by the Energy Commission and various Ghana energy agencies, with support by the Integrated Resource and Resilience Planning (IRRP) Project. Technical and financial support for the IRRP project was provided by the United States Agency for International Development (USAID) who contracted ICF, a U.S. consulting firm, to implement the project. In 2018, the IRRP team developed the first IPSMP 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 2019 IPSMP is the first 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.

Both 2018 and 2019 IPSMP highlight significant excess capacity in the country's generation system. The excess capacity, which is expected to persist until mid-2020s, has associated financial implications, such as payment of capacity charges for plants that may not be fully dispatched until demand picks up in the future. Furthermore, the sector's financial difficulties stem from: (a) high cost of fuel used by thermal power plants; (b) gas supply shortages; (c) high payments for installed capacity to Emergency Power Plants (EPPs) and Independent Power Producers (IPPs); (d) high distribution losses; (e) low revenue collections by Electricity Company of Ghana (ECG) and Northern Electricity Distribution Company (NEDCo); and (f) non-payment by Government entities. Due to these factors, electricity sector revenues from tariff collection do not cover costs—the revenue gap in 2016 was $794 million, according to a World Bank report published in 2018.[1]

In response, the Government of Ghana (GoG) initiated an Energy Sector Recovery Plan (ESRP) in 2018 with the objective of curtailing this financial drain and averting such further occurrence going forward. The immediate objective of the ESRP was 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 the 2018 and the 2019 versions 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.

O. A. N.

Ing. Oscar Amonoo-Neizer.
Executive Secretary, Energy Commission
4 November 2019

[1] http://documents.worldbank.org/curated/en/953141527091798128/pdf/Project-Information-Document-Integrated-Safeguards-Data-Sheet-Ghana-Energy-Sector-Transformation-Initiative-Project-P163984.pdf - Ghana - Energy Sector Transformation Initiative Project (P163984)

ACKNOWLEDGEMENTS

The 2019 Integrated Power Sector Master Plan (IPSMP) was updated by the Energy Commission and the Integrated Resource and Resilience Planning (IRRP) team. Financial and technical support were received from USAID, Ghana, through its funding of the IRRP project, which was implemented by ICF[2], a US-based consulting firm.

The Energy Commission and the IRRP team wish to express their gratitude to the USAID Ghana Mission, for sponsoring the IRRP project with support from Power Africa. The feedback received from the USAID's local Energy Team (Mark Newton and Dorothy Yeboah Adjei) during the update of the IPSMP has been very helpful.

The Energy Commission and the IRRP team acknowledge the important role played by officials from the Ministry of Energy in their sustained support for the 2019 update of the IPSMP and the guidance provided to the IRRP Technical Committee.

The Energy Commission and IRRP team 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 2018 IPSMP. They allowed their technical staff to work closely with the IRRP team, 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)
National Electricity Distribution Company (NEDCo.)
Enclave Power Company (EPC)
Public Utilities Regulatory Commission (PURC)
Energy Commission of Ghana (EC)
Ghana National Petroleum Corporation (GNPC)
Ghana National Gas Company Ltd. (GNGC)

The IRRP Technical Committee (see below) was established from these agencies, and these members contributed their time generously to ensure that the 2019 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 2019 Update of the IPSMP report was based on analysis of Ghana's power system as of the end of 2018 using ICF's power planning modelling tool, the Integrated Planning Model (IPM®). A Core IPM Modelling team (see below for members) was instituted to support the 2019 update, and their contributions to the update is also duly acknowledged.

Finally, the tireless efforts and contribution of the ICF Ghana's IRRP team, sub-consultants, and the short-term technical assistants (STTAs), listed below, were critical to the success of this project and update, and they are all gratefully acknowledged.

[2] www.icf.com

Technical / Advisory Committee

Name	Institution	Designation
Joseph Essandoh-Yeddu	Energy Commission	Former Director, SPPD
Nii Darko K. Asante	Energy Commission	Director, Technical Regulation
Salifu Addo	Energy Commission	Ag. Director, SPPD
James Dimitrus	MoEn	Head of Revenue Monetary Unit
Abdul-Noor Wahab	VRA	Manager
Frank Otchere	GRIDCo	Manager, SCC
Ben Ntsin	GRIDCo	Director, Engineering
Kassim Abubakar	GRIDCo	Electrical Engineer
Stephen Debrah	GRIDCo	Principal Operations Planning Engineer
Godfred Mensah	PDS	Gen. Manager, System Planning
Oscar Neizer	PURC	Director
Hamis Ussif	GNPC	Manager, Gas
Sam-Arthur	GNPC	Gas Business
Andrew Adu	GNGC	Commercial Manager

IPM Core Team

No.	Name	Institution	Position/Function
1	Hanson Monney	MoEn	Engineer
2	Kwasi Twum Addo	MoEn	HSSE
3	Salifu Addo	EC	Ag. Director
4	Simpson Attieku	EC	Energy Economist/Planning
5	Jonathan Walker	VRA	Engineer
6	Isaac Owusu	VRA	Engineer
7	Justice B. Kyere	BPA	Opt. Manager
8	Monica Debrah	GRIDCO	Planning Tech Eng.
9	Getrude Opoku	GRIDCo	Engineer
10	Adjoba Bentil	GRIDCo	Engineer
11	Steven Debrah	GRIDCo	P.O.P.E
12	Ekow Appiah Kwofie	ECG	System Planning Engineer
13	Albert Annan	PDS	Elec. Engineer
14	Patricia P. Sasu	PDS	Snr. Elect. Engineer
15	Nutifafa Fiasorgbor	PURC	Manager, ESPM
16	Robert S. Addo	PURC	Manager, RE
17	Daniel O. Yeboah	GNPC	Officer (gas business)
18	Doe. E. Mensah	GNPC	Commercial
19	Sam Arthur	GNPC	Commercial

ICF Ghana (IRRP Project Team)

Name	Designation
Dr. Ananth Chikkatur	Chief of Party
Maxwell Amoah	Deputy Chief of Party
Matt Boyer	Program Manager
Bernard Modey	Senior Power Expert
William Sam-Appiah	Project & Programme Development Expert
Maame Tabuah Ankoh	Renewable Energy Specialist
Mawunyo Dzobo	Planning and Modelling Specialist
Winfred Lamptey	Energy Modeler
Charles Acquaah	M & E and Capacity Building Specialist
Abdul-Razak Saeed	Climate Resilience Specialist
Mariam Fuseini	Climate Resilience M & E Specialist
Edith Mills-Tay	Office Manager
Louisa Amissah	Office Assistant
Julius Abayateye	Consultant

ICF U.S. Experts

Name	Designation
Juanita Haydel	IRRP Senior Adviser
Maria Scheller	Modelling Expert
Shanyn Fitzgerald	Energy Markets Technical Advisor
Ken Collison	Generation & Transmission Expert
Andrew Kindle	Demand Forecast Expert
Brendan Casey	Statistics Expert
Amit Khare	Energy Efficiency Expert
Raymond Williams	Thermal Power Technology Expert
Michael McCurdy	Renewable Power Technology Expert
Molly Hellmuth	Climate Change/Resilience Expert
Joanne Potter	Climate Change/Resilience Expert
Travis Michalke	Energy Efficiency Expert

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
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 reactor
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

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 2019 version of the IPSMP incorporates feedback received from various stakeholders in the power sector who reviewed the 2018 version, which was published by the Ghana Energy Commission on its website. This update also includes the latest electricity and peak demand projections, fuels 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 all 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 ongoing development of the Ghana power sector.

To instil discipline into the energy sector and curtail the financial challenges in the energy sector, the GoG has put in place an Energy Sector Recovery Plan (ESRP), a strategic plan with the goal of ensuring financial viability and sustainability as well as the adoption of good governance practices 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 annual 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 sustainable socio-economic development of the country.

The IPSMP also serves as the power sector component of a broader Energy Commission's Strategic National Energy Plan (SNEP). Furthermore, it is expected that the assumptions and inputs for the Annual Supply – Demand Plans, the Transmission Master Plan, and the Distribution Master Plans will all conform with the assumptions and inputs used to develop the IPSMP (see Figure 1). It is also expected that the input, assumption and results of the IPSMP will dovetail into other broader plans, such as the Gas Master Plan and the Renewable Energy Master Plan, as well as strategic roadmaps, such as the nuclear roadmap (see Figure 2). Finally, the planning and development of the SNEP and the IPSMP need to be undertaken within the context of regional level plans such as the WAPP Master-plan.

Figure 1: IPSMP in the Hierarchy of Power Sector Planning

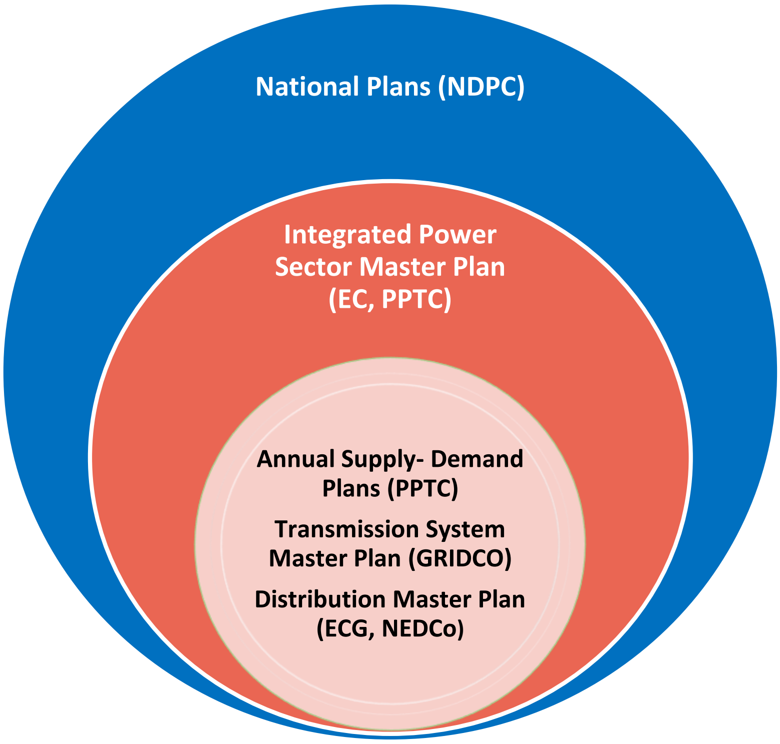
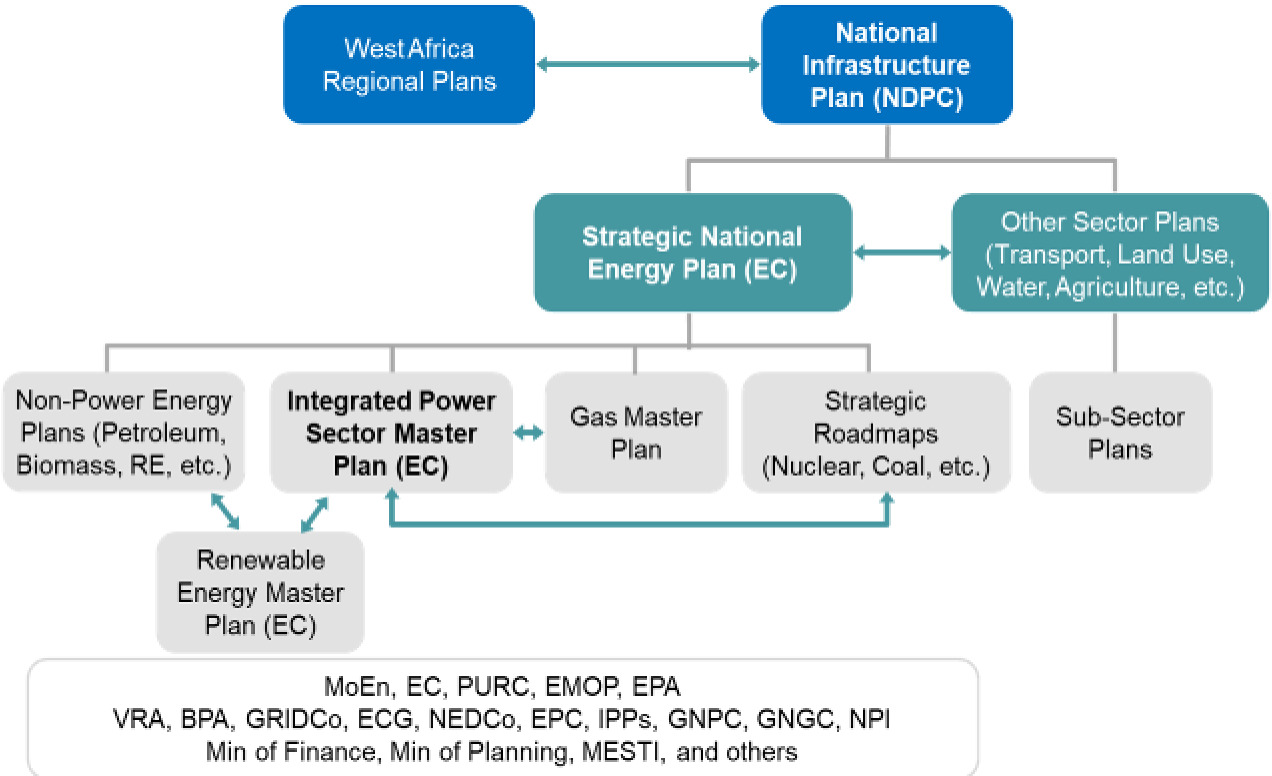


Figure 2: IPSMP within the Broader Planning Framework in Ghana and West Africa



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 meeting held at La Palm Royale Hotel (June 17 and 18, 2019) to carry out a comprehensive update of the assumptions and inputs required for the 2019 version of IPSMP) were held to seek feedback on the 2018 version and inputs into the 2019 update report. Inputs from these workshops have been included in the 2019 final version. It is expected that the next full IPSMP update would be in 2021-22 (and thereafter, at least every 3 years). However, the modelling will be updated every 4-6 months, on a regular basis.

Similar to the 2018 IPSMP report, the 2019 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®)[3]. 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. In addition to the results of the modelling work, the 2019 IPSMP version also includes elements related to implementation of the plan such as recommendations for procurement, institutional arrangements, financing, inter-ministerial coordination and M&E in the framework of a decision hierarchy that conforms to what is recommended in the ESRP.

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 realising 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).

3 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 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, with support from the IRRP project.

1.2. APPROACH FOR DEVELOPING 2019 IPSMP - UPDATE

The 2019 IPSMP, an update of the 2018 IPSMP, was undertaken by members of the Technical Committee with support from the IRRP team, with oversight and feedback from the Energy Commission. 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 2018 IPSMP report, and comprehensive discussions of the modelling framework and model results to arrive at a consensus for the 2019 IPSMP. The EC and MoEn formed the Steering Committee for the 2019 Update.

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 Technical Committee and the IPM Core 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.

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 3 shows the framework for the IRRP and the analyses leading to the 2019 IPSMP update. The existing working relationships established by the MoEn and EC for the IRRP Project as illustrated in Figure 4 was also used for the 2019 IPSMP update.

1.2.1. Feedback and Update Process for IPSMP

The draft 2018 IPSMP was presented to the Ministry of Energy, Volta River Authority, Ghana Grid Company, Power Distribution Services Company, Northern Electricity Distribution Company and Ghana Gas Company, among others, for their review and comment. The feedback from these stakeholders was incorporated into the Final 2018 IPSMP and uploaded on the Energy Commission website. Comments on the Final 2018 IPSMP fed into the development of the 2019 IPSMP.

Training on the Ghana-IPM and further analysis have been undertaken to empower the Ghana energy stakeholders to acquire the necessary skills to update the 2018 IPSMP and develop 2019 IPSMP, as well as carry out updates on regular basis in the future (ideally every 3 years).

Figure 3: Framework for IRRP

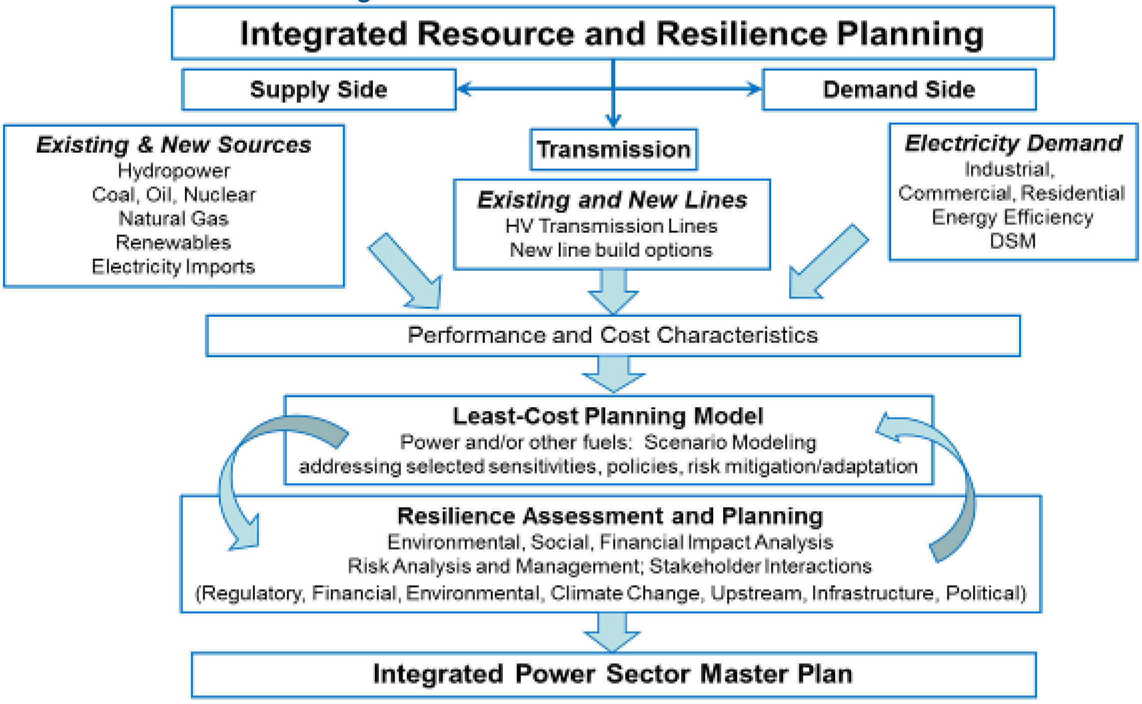
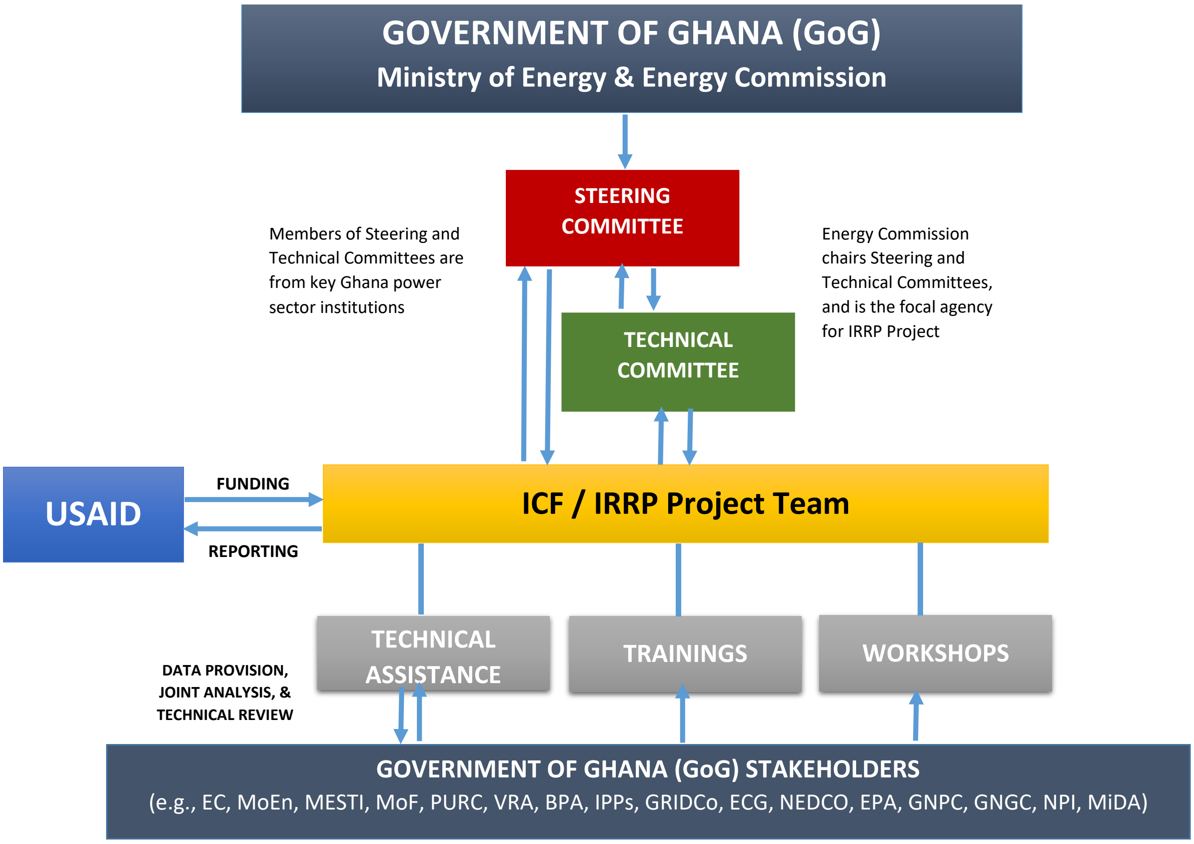


Figure 4: Working Relationships for the IRRP Project



1.3. ORGANISATION OF THE 2019 IPSMP REPORT

The information presented in this 2019 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. It highlights the key issues in the 2019 Update such as the goal and objectives of the IRRP Project and the vision and objectives of the IPSMP. It also provides a summary of the key attributes of the IPSMP, including the Least-Regrets Portfolio, short-term action plan for implementation, hierarchy of implementation recommendations, recommendations for future planning and procurement in the power sector in line with the ESRP, climate change risk assessment, management and monitoring of the plan, and updating of IPSMP.

Volume 2 includes an overview of the IPSMP, the vision and objectives of the IPSMP, and the IPSMP development process, including the role of the IRRP; project background and process; and highlighting the IRRP vision and objectives. It then provides a background and summary of key issues, the current planning process and institutional roles, and the historical and current planning environment.

It provides a description of the modelling framework used for the IPSMP and the key variables used in the analysis such as demand, economic growth, energy efficiency and demand-side management (DSM), energy supply, hydrology, natural gas resources and infrastructure, fuel cost and availability 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.

The volume also includes a series of recommendations associated with various parts of the electricity value chain, as well as the future process for planning and procurement of new power generation in Ghana to conform with the recommendations of the ESRP. Finally, the last part of Volume 2 identifies the potential implementation challenges and provides recommendation on appropriate studies for the future updates of IPSMP.

Volume 3 contains the relevant data used and analysis conducted for the development of the 2019 IPSMP in a stand-alone set of appendices.

2. BACKGROUND AND KEY ISSUES

2.1. THE GHANA POWER SYSTEM ASSESSMENT: UPDATE UP TO 2019

The goal of Ghana's power sector is to efficiently supply power in an environmentally sustainable manner 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 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 2019 IPSMP report updates the 2018 IPSMP version, which provided an assessment of the performance of the country's power sector (up to 2016). The 2019 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 at the end of 2016 was 11,518 GWh. This increased by 6.3% to 12,246 GWh in 2017. In 2018, the total electricity consumption of 13,185 GWh was 7.7% more than that of the previous year (2017). The 2018 IPSMP report projected a total electricity consumption of 12,953 GWh in 2017, which was 5.8% higher than the actual and 13,893 GWh in 2018, which was also 5.4% higher than the actual. 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 which 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 2016, the maximum coincident peak demand, which occurred on November 29, was 2,078 MW. This increased by 5.4% to 2,192 MW in 2017 (recorded on November 13). The maximum coincident peak demand increased by 15.2% to 2,525 MW in 2018 and this occurred on December 17. The 2018 IPSMP report projected a maximum coincident peak demand of 2,126 MW in 2017, which was 1.5% lower than the actual and 2,343 MW in 2018, which was also 7.8% lower than the actual.

In terms of electricity consumption by customer class, the Special Load Tariff 4 (SLT) accounted for about 45.2% and 45.0% of the total electricity consumption in 2016 and 2017, respectively. In 2018, SLT customers accounted for 43.3% of the total electricity consumption. The next major electricity consumption customer is the residential, which accounted for 38.4% and 36.2% of the total electricity consumption in 2016 and 2017, respectively. In 2018, the residential customers accounted for 41.4% of the total electricity consumption. Non-residential customers5 accounted for 10.4% and 12.5% of the total electricity consumption in 2016 and 2017 respectively. In 2018, non-residential customers accounted for 9.5% of the total electricity consumption. The electricity consumption by street and traffic lights accounted for about 6% on the average from 2016 to 2018.

[4] Special load tariff customers of ECG/PDS and NEDCo, as well as bulk customers of VRA, including VALCo

[5] Non-residential customers include Banks, Offices, Stores, Shopping Malls etc.

Electricity Imports and Exports

Table 1: Electricity Imports and Exports from 2016 to 2018

	2016	**2017**	**2018**
Imports	745	320	140
Exports	187	268	740
Net Exports	-558	-52	600

Source: Energy Commission's National Energy Statistics, 2019

As shown in Table 1 above, net electricity import in 2016 was 558 GWh. This decreased significantly to 52 GWh in 2017. This is line with government policy to decrease electricity imports but rather increase electricity exports to become a major net electricity exporter in the sub-region by 2020. In 2018, the country had a net export of 600 GWh of electricity.

Electricity Supply

The total installed and dependable electricity generation capacity from the end of 2016 to the end of 2018 is presented in Table 2.

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

	2016		2017		2018	
	Installed	Dependable	Installed	Dependable	Installed	Dependable
Hydro	1,580	1,468	1,580	1,380	1,580	1400
Thermal	2,192	1,995	2,796	2,568	3266	3038
RE sources[6]	22.6	18	22.6	18.1	42.6	34.1
Total	**3,794.6**	**3,481.1**	**4,398.6**	**3,966.1**	**4,888.6**	**4,472.1**

Source: Energy Commission's National Energy Statistics, 2019

The total installed electricity generation capacity as at the end of 2016 was 3,794.6 MW compared to a peak demand of 2,078 MW. In 2016, hydropower accounted for 41.6% of the total installed generation capacity, whilst thermal power accounted for 57.8%. In addition, RE sources accounted for 0.6% of the total installed capacity. The total installed capacity in 2016 increased by about 16.0% to 4,398.6 MW in 2017 compared to a peak demand of 2,192 MW. In 2017, hydropower accounted for 35.9% of the total installed capacity whilst thermal increased 63.6% and RE source was 0.5%. The total installed generation capacity as at the end of 2018 was 4,888.6 MW compared to a peak demand of 2525 MW. The total installed capacity in 2018 was about 11.0% increase over that of the previous year. In 2018, the share

[6] RE sources include Biogas and Solar PV

of hydropower decreased to 32.3% of the total installed generation capacity, thermal further increased to 66.8% with RE sources increasing to 0.9%.

The increase in the share of thermal in 2017 was due to the addition of the following thermal power plants to the 2016 generation system capacity position: 140 MW AKSA, which came online in 2017 and the upgrade of Sunon Asogli plant by 360 MW in 2016/2017. The further increase in the share of thermal in 2018 was due to 360 MW Cenpower and 30 MW Genser power plants coming online in 2018. The share of electricity supply from RE sources in 2018 was maintained due to the 20 MW Meinergy Solar PV plant and the 30 kW biogas plant coming online in 2018.

The total amount of electricity (GWh) supplied from domestic plants from 2016 to 2018 according to technology is presented in Table 3.

Table 3: Total Electricity supplied from domestic plant

	2016	2017	2018
Hydro	5,561	5,616	6,017
Thermal	7,435	8,424	10,195
RE Sources	27	28	33
Imports	745	320	140
Total	**13,768**	**14,388**	**16,385**

Source: Energy Commission's National Energy Statistics, 2019

The total amount of electricity supplied from domestic power plants according to technology and imports was 13,768 GWh in 2016. In 2016, electricity supplied from hydropower accounted for 40.4% of the total electricity supplied whilst thermal power accounted for 54%. Electricity supplied from imports was responsible for 5.4% and that from RE sources was 0.2% of the total supplied. The total amount of electricity supplied in 2016 increased by 4.5% to 14,388 GWh in 2017. In 2017, the share of electricity supplied from hydropower sources decreased to 39.0% of the total electricity supplied whilst that from thermal power increased to 58.5%. The share of electricity supplied from RE sources in 2017 remained at 0.2% and that for imports decreased to 2.2% of the total electricity supplied. The total annual electricity supplied in 2017 increased by about 14.0% to 16,385 GWh in 2018. The share of annual electricity supply from hydropower sources further decreased in 2018 to 36.7% of the total electricity supply. The share of thermal increased to 62.2% whilst that from RE sources remained at 0.2% and imports decreased to 0.9% of the total electricity supplied in 2018.

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. An assessment of the amount of historical inflows into the Volta Lake up to 2016 has been reported in the 2018 IPSMP report. The recorded total annual inflows into the Volta Lake for 2016 was 30.25 Million Acre Feet (MAF) or 37.31 Billion cubic metres. The recorded total annual inflow into the Volta Lake increased by 8.2% to 32.74 MAF (40.38 Billion cubic metres) in 2017. In 2018 the recorded total inflow was 40.01 MAF (49.35 Billion cubic metres), which was 22.2% higher than the inflow in 2017. The inflows from 2016 to 2018 were all above the long-term average annual inflow of 30 MAF (37.00 Billion cubic metres).

Total hydropower generation (from Akosombo, Kpong and Bui) Hydro Power Plants (HPP) increased by 0.99% from 5561 GWh in 2016 to 5616 GWh in 2017. In 2018, hydropower generation from the HPP was 6017 GWh, which was 7.14% higher than the generation in 2017.

Due to the above-average inflows into the Volta Lake from 2016 to 2018, the country may be expected to derive sufficient amounts of hydropower generation from the HPP in the next few years. However, this will depend on the proper coordination of maintenance activities, the availability and reliability of the thermal units, and the strict adherence to planned hydro draft rates, which are determined with reference to the long-term average draft rate.

- **Natural Gas Supply**

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

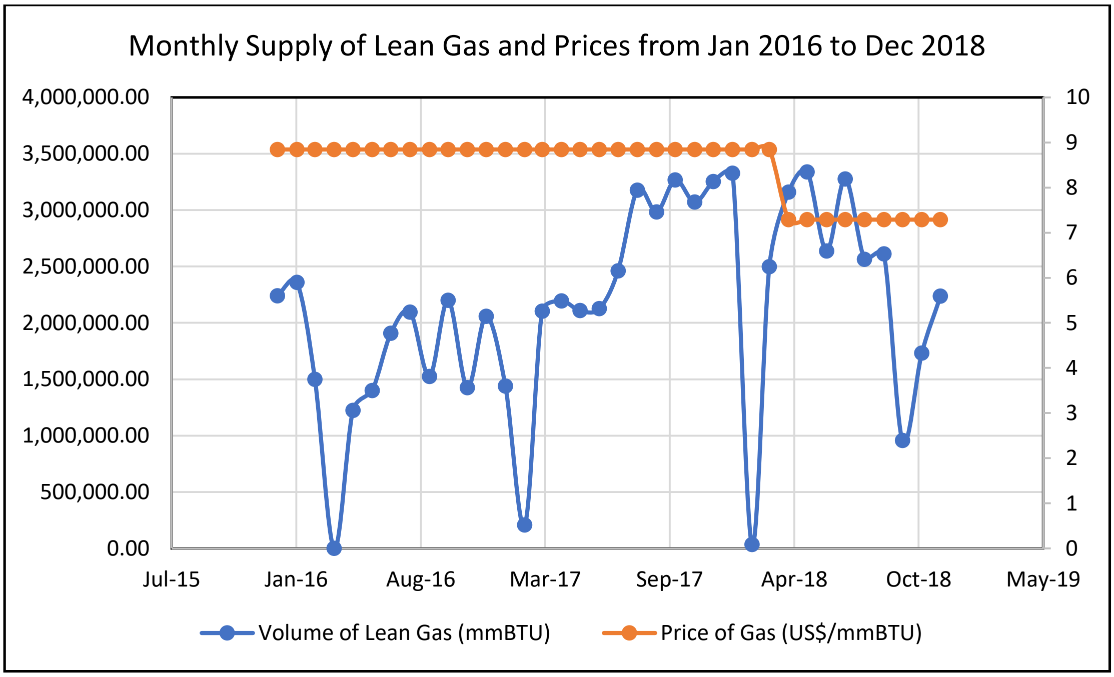
In 2016, 4.0 TBtu of natural gas was imported for electricity generation from Nigeria (through the WAGP) at a total cost of US$ 35.97 million. The price of the Nigerian natural gas in 2016 was about US$ 8.98/MMBtu. Natural gas from Nigeria for electricity generation more than doubled to 11.7 TBtu in 2017 at a total cost of US$ 102.31 million. The price of natural gas in 2017 was about US$ 8.73/MMBtu. In 2018, natural gas imports from Nigeria for electricity generation increased further to 25.3 TBtu at a total cost of US$ 220.54 million and at a price of US$ 8.71/MMBtu.

The total amount of lean natural gas supplied from the Atuabo Gas Processing Plant to the thermal power plants for electricity generation in 2016 was 19.94 TBtu. In 2016, the price of domestic lean natural gas was US$ 8.84/MMBtu. The domestic lean natural gas supplied in 2016 increased by 42.4% to 28.39 TBtu in 2017 with an average price of US$ 8.84/MMBtu. In 2018, the total gas supplies decreased by 0.09% to 28.37 TBtu, with an average price of US$ 7.68/MMBtu. This average price of US$ 7.68/MMBtu was derived from the price of US$ 8.84/MMBtu before a gas price review in March 2018 to a price of US$ 7.29/MMBtu. The quantity and price of lean natural gas supplied by

Ghana National Gas Company from the Atuabo Gas Processing Plant to the Aboadze Thermal complex is shown in Figure 5.

The challenges with gas supplies between 2016 and 2017 as a result of (1) decreased and fluctuating gas flows on the WAGP from Nigeria and (2) gas interruptions owing to compressor trips affecting gas supply from Atuabo, have been largely addressed by works on the compressors and the discovery of large volumes of domestic gas in Ghana which have, consequently, improved gas supplies for power generation. Further, the implementation of the Takoradi – Tema Interconnection project in mid-2019 to interconnect Ghana Gas pipeline systems to the West African Gas Pipeline has enabled reverse gas flow from domestic sources to Tema through the WAGP pipeline. This has further improved reliability of gas supply to the power generating plants in Tema.

Figure 5: Monthly supply of Lean Gas and Prices



Source of Data: PIAC Annual Report for 2016, 2017 and 2018

- **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. With the movement of the Karpowership from Tema to Takoradi in August 2019, only the AKSA plant in Tema continues to use HFO for power generation. A significant amount of savings is expected to be derived from the shift from liquid fuels to natural gas for thermal electricity generation.

Electricity Transmission

The electricity supplied from generating plants and imports are 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-2019. 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 2019 as new projects come online. The total transformer capacity stood at about 8064 MVA at the end of 2018.

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 connection at 33kV for some mines and border communities of Cote d'Ivoire, Togo and Burkina Faso.

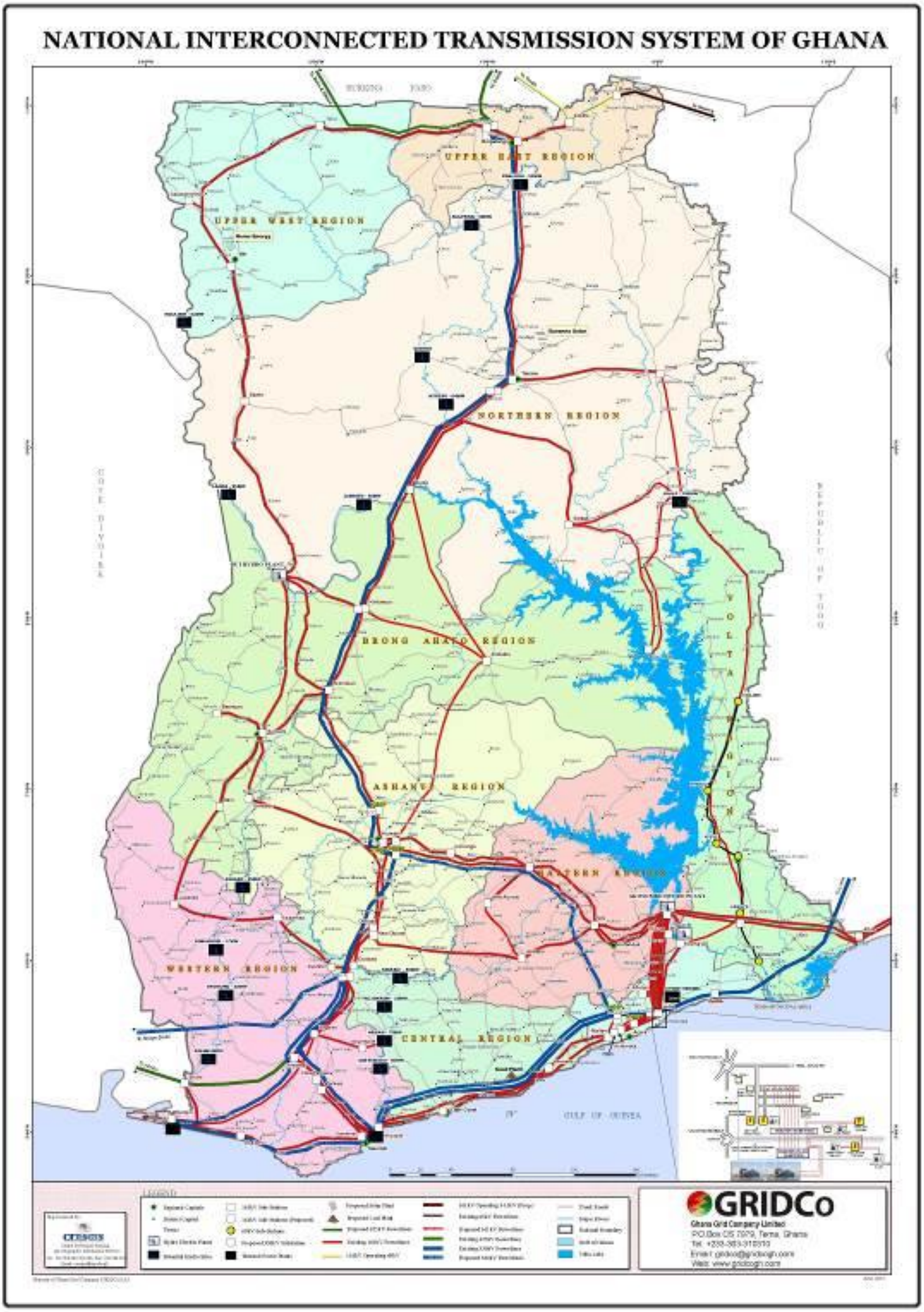
The total amount of electricity transmitted and the losses on the transmission system are presented below.

Table 4: Total Energy and Transmission losses

	2016	**2017**	**2018**
Transmitted (GWh)	13,700	14,308	15960
Losses on transmission (GWh)	607	540	707
% Losses on transmission	4.4	3.8	4.4

Source: Energy Commission's National Energy Statistics, 2019

The total amount of electricity transmitted in 2016 increased by 4.4% to 14,308 GWh in 2017. The electricity transmitted in 2018 was 11.5% higher than that which was transmitted in 2017. The average of the transmission losses from 2016 to 2018 was about 4.2%. Some projects were initiated in 2018 and are expected to be completed by 2020 to resolve transmission constraints, transformer overloads and reduce losses. Some of these projects are the Pokuase Bulk Supply Point; and the Afienya Bulk Supply Point.


NATIONAL INTERCONNECTED TRANSMISSION SYSTEM OF GHANA
UPPER EAST REGION
UPPER WEST REGION
NORTHERN REGION
BRONG AHAFO REGION
ASHANTI REGION
EASTERN REGION
WESTERN REGION
CENTRAL REGION
VOLTA REGION
GULF OF GUINEA
LEGEND
GRIDCo
Ghana Grid Company Limited
P.O.Box CS 7979, Tema, Ghana

Electricity Distribution

The distribution companies in the country are ECG/PDS, NEDCo, and Enclave Power Company (EPC). In 2016, the total amount of electricity distributed in the country was 7,978 GWh. This increased by 8.0% to 8,619 GWh in 2017. In 2018, the total amount of electricity distributed was 9,317 GWh, which was 8.1% more than the previous years.

Table 5: Electricity Distribution in Ghana

	2016	2017	2018
ECG/PDS	7,115	7,575	8,251
NEDCo	763	889	910
EPC	100	155	156
Total	7,978	8,619	9,317

Source: National Energy Statistics, 2019

It can be observed in Table 5 that ECG/PDS account for about 88% of the total electricity distributed in the country from 2016 to 2018. This is followed by NEDCo, which accounted for about 10% of the total electricity distributed, with EPC accounting for about 2%.

The total electricity consumption according to tariff class from 2016 to 2018 is presented in the table below:

Table 6: Electricity consumption according to tariff class

	2016		2017		2018	
	GWh	%	GWh	%	GWh	%
Residential	3,932	38.4	3,931	36.2	4,824	41.4
Non-residential	1,068	10.4	1,356	12.5	1,103	9.5
Special Load Tariff	4,626	45.2	4,880	45.0	5,046	43.3
Street Lighting	603	5.9	679	6.3	683	5.9
Total	**10,229**	**100.0**	**10,846**	**100.0**	**11,656**	**100.0**

Note: This includes electricity consumed by VRA Bulk customers and VRA Townships

The total electricity consumption in 2016 was 10,229 GWh. This increased by 6.0% to 10,846 GWh in 2017 before increasing further by 7.5% to 11,656 GWh in 2018. The main consumers of electricity in the country was SLT customers[7] who accounted for between 43.3% to 45.2% of total electricity consumed annually from 2016 to 2018.This was followed by residential consumers who consumed between 36.2% to 41.4% of the total electricity consumed from 2016 to 2018. The non-residential consumers accounted for 10.4% of the total electricity consumed in 2016. The share of the non-residential consumers increased to 12.5% in 2017 before decreasing to 9.5% in 2018. The share of electricity consumed for street lighting was

[7] Special load tariff customers of ECG/PDS and NEDCo as well as bulk customers of VRA including VALCO

5.9% of the total electricity consumed in the country in 2016. The share of electricity consumed for street lighting increased to 6.3% in 2017 before decreasing to 5.9% in 2018.

The total amount of electricity lost (i.e., both technical and commercial) annually in distribution was estimated to be about 2,586 GWh in 2016, about 24.5% of the total electricity purchased. The amount of electricity lost decreased by about 1.5% to 2,546 GWh, which is 22.8% of the total electricity purchased in 2017. The electricity lost in distribution increased to 3,061 GWh, which is about 24.7% of the total electricity purchased in 2018.

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 begun the implementation of prepaid electricity metering systems for both the private sector and government agencies. The sector is also pursuing other solution 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. As part of the reforms targeted at addressing the distribution challenges, GoG signed a power concession agreement with Power Distribution Services (PDS), a private investor, in March 2019 to take over the management of some of the assets and operations of ECG with the aim of turning around the fortunes of the distribution utility. This arrangement is expected to reduce distribution losses (commercial and technical) to conform with industry standards whilst delivering improved distribution services to customers.

Electricity Access

The national electrification access rate increased from 83.24% in December 2016 to 83.62% in September 2017 with about 289 additional communities being connected to the national grid as part of the rural electrification programme. [8] Figure 6 shows the Electricity Access Map of Ghana in 2017.

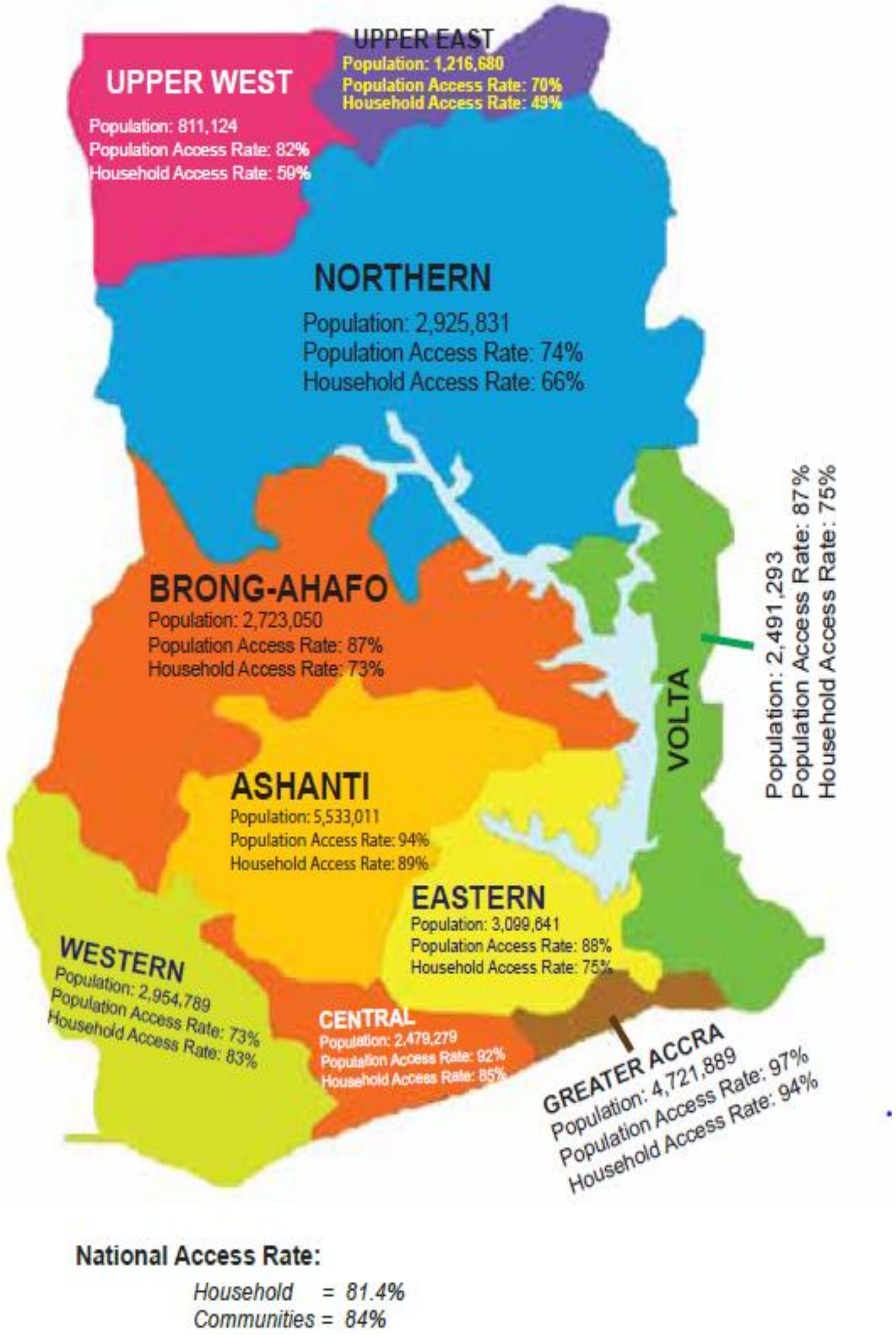
The national access rate to electricity increased from 84.15% as at the end of December 2017 to 84.32% at the end of 2018[9], with 700 additional communities being connected to the national grid. The access rate at the end of 2018 comprised 93% access rate in urban localities as compared to 71% in rural localities. This access rate is expected to increase further to about 95.0% by 2020 to achieve the universal access target for Ghana.

However, as a result of the cost of infrastructure, some parts of the country such as island communities and some Volta lakeside communities may not have access to the national grid for a long time to come. To ensure the achievement of the 2020 national access rate, GoG has been participating 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 was tailored to expanded 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.

[8] https://www.mofep.gov.gh/sites/default/files/pbb-estimates/2018/2018-PBB-MoEn.pdf
[9] https://www.mofep.gov.gh/sites/default/files/pbb-estimates/2019/2019-PBB-MoEn.pdf

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 85% as at the end of 2018 to 95% by 2025 (representing 100% electricity access). However, there is still a challenge in arriving at a suitable tariff that addresses the investments associated with mini-grid and still be affordable to consumers who are mostly low-income earners.

Figure 6: Electricity Access Rate for Ghana



Source: http://www.energycom.gov.gh/files/2018%20Key%20Energy%20Statistics.pdf

Electricity Rate Setting

The Public Utility Regulatory Commission (PURC), among other responsibilities, provides guidelines for rates to be charged for the provision of utility services, and examines and approves water and electricity rates based on tariff proposals submitted by regulated utilities. The PURC undertakes quarterly tariff reviews using an Automatic Adjustment Formula (AAF) to sustain the real value of the End-User-Tariff (ETU) for electricity consumed. This is done by adjusting key variables in the formula based on variations in factors such as fuel prices (light crude oil, natural gas, HFO, etc.), foreign exchange rates, inflation rates and the generation mix (i.e., actual proportions of hydro, thermal and RE resources generated and dispatched). The PURC also approves Feed-in-Tariffs for electricity supplied from RE sources.

The utility companies in the electricity sector regulated by the PURC are the Volta River Authority (VRA), Northern Electricity Distribution Company (NEDCo) Ltd., a subsidiary of VRA, Ghana Grid Company Ltd. (GRIDCo), Electricity Company of Ghana (ECG)/Power Distribution Services (PDS), and the Enclave Power Company Ltd. Table 7 shows the average EUT approved for these utilities from 2016 to 2019. The Table 7 shows that the Bulk Generation Charge (BGC) approved for electricity generators like VRA did not change from April 2016 until after the first half of March 2018. In March 2018, the PURC undertook a major tariff review, which increased the tariff for electricity generators like VRA by 37%. In the case of the Composite BGC approved for electricity generators (i.e., VRA and IPPs), the major tariff review in March 2018 increased the rate by 19%. Both the BGC and Composite BGC were maintained from March 15, 2018 until July 15, 2019, when they were increased by 0.4% and 5%, respectively.

Table 7: PURC End-User-Tariff from 2016 to 2019 for Utilities Companies (GHp/kWh).

	01-Apr-16	01-Jul-16	01-Jan-17	01-Apr-17	01-Jul-17	15-Mar-18	15-Jul-18	16-Sep-18	01-Oct-18	15-Jul -19
BGC VRA [1]	21.08	21.08	21.08	21.08	21.08	28.91	28.91	28.91	28.91	29.03
Composite BGC [2]	35.97	35.97	35.97	35.97	35.97	42.98	42.98	42.98	42.98	45.25
TSC 1 [3]	5.59	5.59	5.59	5.59	5.59	3.04	3.04	3.04	3.04	5.52
TSC 2 [4]	3.15	3.15	3.15	3.15	3.15	1.70	1.70	1.70	1.70	1.93
DSC 1 [5]	22.22	22.22	22.22	22.22	22.22	18.66	18.66	18.66	18.66	16.03
DSC 2 [6]						12.09	12.09	12.09	12.09	14.89
DWC [7]	32.74	32.74	32.74	32.74	32.74	30.76	30.76	30.76	30.76	30.93
USD-GHS Exchange rate	3.830	3.940	4.240	4.270	4.38	4.41	4.79	4.75	4.82	5.31

Notes:
1 – Bulk Generation Charge for VRA
2 – Composite BGC
3 – Transmission Service Charge to recover cost of transmission network operations
4 – Transmission Service Charge to recover cost of transmission losses
5 – Distribution Service Charge to recover cost of distribution network operations
6 – Distribution Service Charge to recover cost of distribution losses
7 – Distribution Wheeling Charge payable by embedded Bulk Customers

The tariffs covering TSC1 and TSC2 as well as DSC1 and DSC2 also were maintained from April 01, 2016 until the major tariff review in March 2018. The Major Tariff Review of March

2018 decreased the DSC1 by 16% and the TSC1 and TSC2 by about 46%. These tariff levels were maintained until July 2019 when the PURC reviewed them upwards.

The overall tariff change from April 2016 to July 2019 increased by 37% for the BGC and 26% for the Composite BGC tariffs. It can be observed that over the same period from April 2016 to July 2019, the exchange (Forex) rate increased by 39%. Hence, when increases in inflation rate and fuel prices (i.e., natural gas, HFO and LCO) are considered, it is observed that the electricity tariffs (in real terms) approved by the PURC are still below cost recovery tariffs. The long delays of the application of the AAF further affects the revenue mobilization efforts of the utilities. A major challenge that besets the rate setting process is the weakening strength of domestic currency as against the US dollar, which affects utilities' revenues in US dollar terms. Hence, the amount of money required to recover the cost of their operations and to purchase vital equipment, most of which are imported for refurbishment and infrastructure upgrade, may be greatly impaired.

The end-user-tariffs (EUT) of electricity consumers are classified into the following six categories: residential, non-residential and special load tariff (low voltage SLT [SLT-LV], medium voltage SLT [SLT-MV], high voltage SLT [SLT-HV] and high voltage SLT - Mines [SLT-HV Mines]). An assessment of electricity charges according to the end-user tariff classes shows that industrial electricity users (mainly SLT consumers) are higher than those of residential consumers are. This does not encourage efficient use of electricity in the residential sector.

The PURC has been proposing ways to review the tariff structure, to remove all inconsistencies and to ensure that subsidies are directed at only the poor and minimise the financial drain on the utilities. Government has also initiated an effort to develop Energy Sector Recovery Plan to address the many challenges that have resulted in the mounting debt.

Energy Sector Recovery Plan (ESRP)

Compared to the period from 2012 to 2015, the quality of service delivery of the country's power system improved significantly from 2016 to 2019. As at the end of July 2019, the country had almost 5,000 MW of installed generation capacity though the actual peak demand recorded so far (as at May 6, 2019) is 2781 MW. Further to the excess capacity, the significant endowment of natural gas and the potential to increase the installation of more renewable energy facilities, assures Ghana's ability to generate electricity to meet its power sector needs as well as becoming a major exporter of power in the West African sub-region. This is in line with the GoG's energy policy goal of (i) providing adequate, reliable and competitively priced energy for domestic, commercial and industrial use and (ii) becoming a net exporter of electric power in the sub-region.

However, the following challenges continue to persist:

- Unreliable supply of power to the end-user (notwithstanding the excess installed power generation capacity),
- High cost of electricity supply owing to high cost of fuel, and
- The sector's significant financial debts.

To overcome the challenges confronting the sector, the GoG has put in place an Energy Sector Recovery Plan (ESRP). The ESRP will be a well-coordinated programme to implement measures to ensure the turnaround and sustainability of the Energy sector by: (a) restoring the power sector's financial viability, (b) improving sector planning and investment decisions, (c) improving the regulatory framework, and (d) expanding electricity access to remote communities. The scope of the ESRP covers the entire Energy Sector, including the Petroleum sector, but the current plan focusses on the gas to power value chain.

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 IPSMP report. 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.

(iv) Inadequate and unreliable delivery of natural gas and therefore, not meeting planned level of generation from thermal plants. The situation has improved since August 2019 with the implementation of the reverse-flow project.

(v) The absence of a current and detailed Power Sector Master Plan to guide implementation of power system planning recommendations and expansion decisions. The absence of a master plan led to uncoordinated and non-competitive procurement of power plants.

3.2. DEALING WITH PLANNING CHALLENGES

Despite strides made by various agencies within the power sector in planning their short term (operational) to long-term activities, there remained planning coordination and implementation challenges. To resolve these challenges, the power system planning process for the sector has been streamlined with the implementation of the Integrated Resource and Resilience Planning (IRRP) project which brought together all the various stakeholders to work together to develop the Integrated Power Sector Master Plan (IPSMP). The IPSMP provides an analysis of various risks and uncertainties and derive an optimal solution through the consideration of various strategies that have the potential of positively shaping or improving activities within the energy sector. Sensitivity analyses were also carried around the strategies to arrive at the "Least-Regrets" solution that will reflect or provide the strategy that takes into consideration the set of policy objectives for the power sector and which also performs the best under a broad range of potential sensitivities — (i.e., various techno-economic futures that will be resilient/ robust under changing circumstances). The publication of the 2018 IPSMP10 provided a number of recommendations towards tackling the challenges.

Furthermore, other measures such as the (a) Energy Sector Recovery Plan, (b) Energy Supply Procurement Policy; and (c) Least-Cost Fuel Procurement Policy have been proposed to

[10] http://www.energycom.gov.gh/files/Ghana%20Integrated%20Power%20System%20Master%20Plan%20_Volume%201_

address some of the power sector challenges. However, the sustainable development of the power system in the future will depend on the implementation of these proposed policies and the IPSMP recommendations, strict adherence to good power sector governance as well as strong and capable power sector institutions.

3.2.1. **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 fuel 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); 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.

During the IRRP project, detailed analysis of demand forecasts was carried out using historical data collected from ECG/PDS's Automatic Metering Infrastructure (AMI), as well as improved regression analysis using R[11]. The various sector agencies were trained in the use of the R software.

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 6.5%.

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

[11] A Statistical Software

abnormal occurrences on the grid such as periods of power curtailment that suppresses electricity demand to a significant extent.

In order to achieve better monitoring and forecasting of demand growth for electricity, extensive capacity building in econometric modelling, which offers a scientific approach in forecasting electricity demand, has been undertaken for all key power planning stakeholders especially GRIDCo, ECG and NEDCo. In addition, three different forecasts (i.e., reference, high, and low cases) are considered in the IPSMP to address uncertainties.

3.2.2. Energy Efficiency and Demand-Side Management

Energy audits undertaken of various commercial buildings in 2017 under the IRRP project indicated that 10-30% of 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 6.5% of total load forecasted in 2030 (30,307 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 in lowering costs of energy services and for driving economic productivity.

Further energy audits are being undertaken at Kpong, Weija and Keseve Water Headworks and at Dodowa and Okponglo Booster Stations.

3.2.3. Supply-Side Issues

The supply-side options associated with Ghana’s power system are made up of this supply mix: 54.0% thermal power, 40.4% hydro, 5.4% imports and 0.2% renewable energy as at December 2016. This supply mix as at December 2018 was 62.2% thermal power, 36.7% hydro, 0.2% of RE sources and 0.9% imports. 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 recent times (from 2013 to 2015) mainly due to 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.

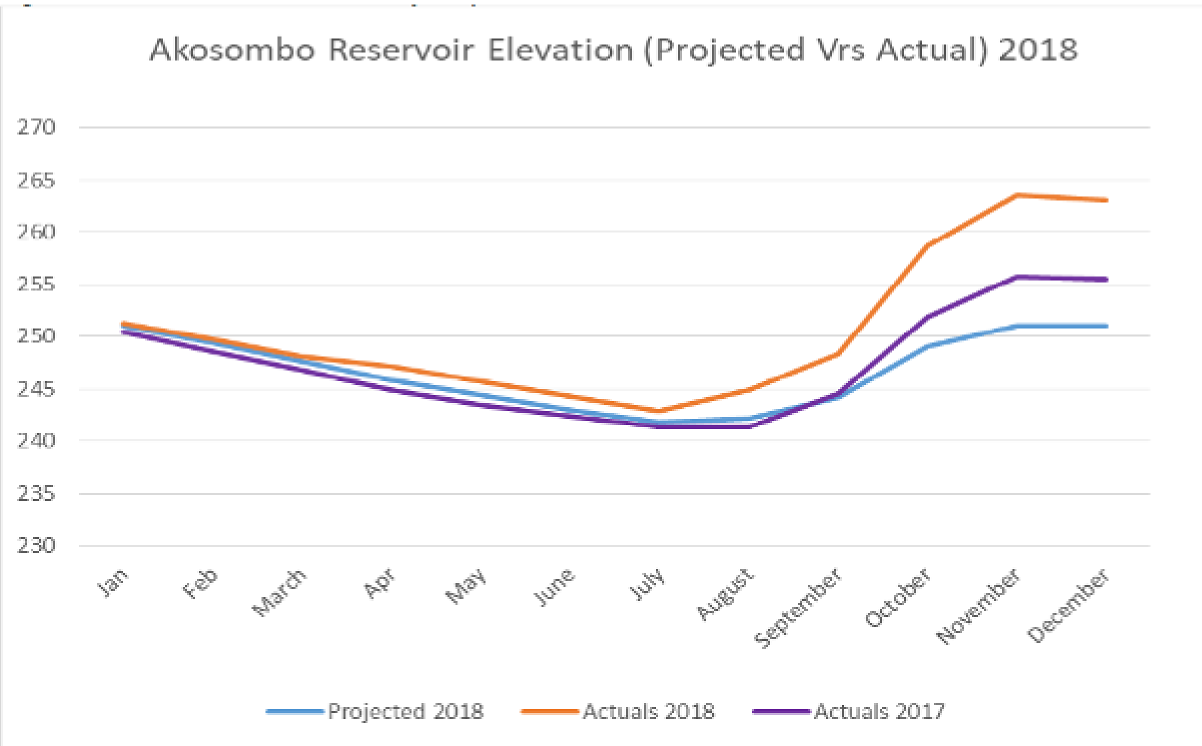
The inflow in the 2016 inflow season (i.e., from June to November) was higher than the flows for each of the years between 2013 through 2015; however, it was lower than the long-term average (LTA) by 6%. Challenges with procurement of fuel supply for thermal generation made it difficult to adhere to 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 elevation of the Volta Lake at the beginning of 2018 was 251.34 feet and when the drafting of the reservoir conformed to planning recommendations (to operate 3 and 5 units of the plant at off-peak and peak respectively), the lake recorded a maximum elevation of 263.67 feet at the end of the 2018 inflow season (reflecting 23.67 feet above the minimum level of 240 feet). Figure 7 shows the actual and projected elevation of the Volta Lake for 2017 and 2018.

In the case of the Bui reservoir, the elevation of the reservoir at the beginning of 2016 was 178.59 meters above sea level (MASL). Similarly, challenges with fuel supply to operate the thermal power plants forced Bui to generate more than projected to support the power system. At the beginning of 2017, the Bui Reservoir level was 175.87 MASL but dropped to a minimum level of 169.61 MASL at the end of the dry season due to over-drafting of the reservoir in the first quarter of 2017. At the end of the inflow season the reservoir level rose to a maximum level of 176.71 MASL. The total energy generated in 2017 was 581.79 GWh compared to the projected of 841 GWh owing to lower than projected inflow into the lake.

Figure 7: Akosombo Elevation 2018



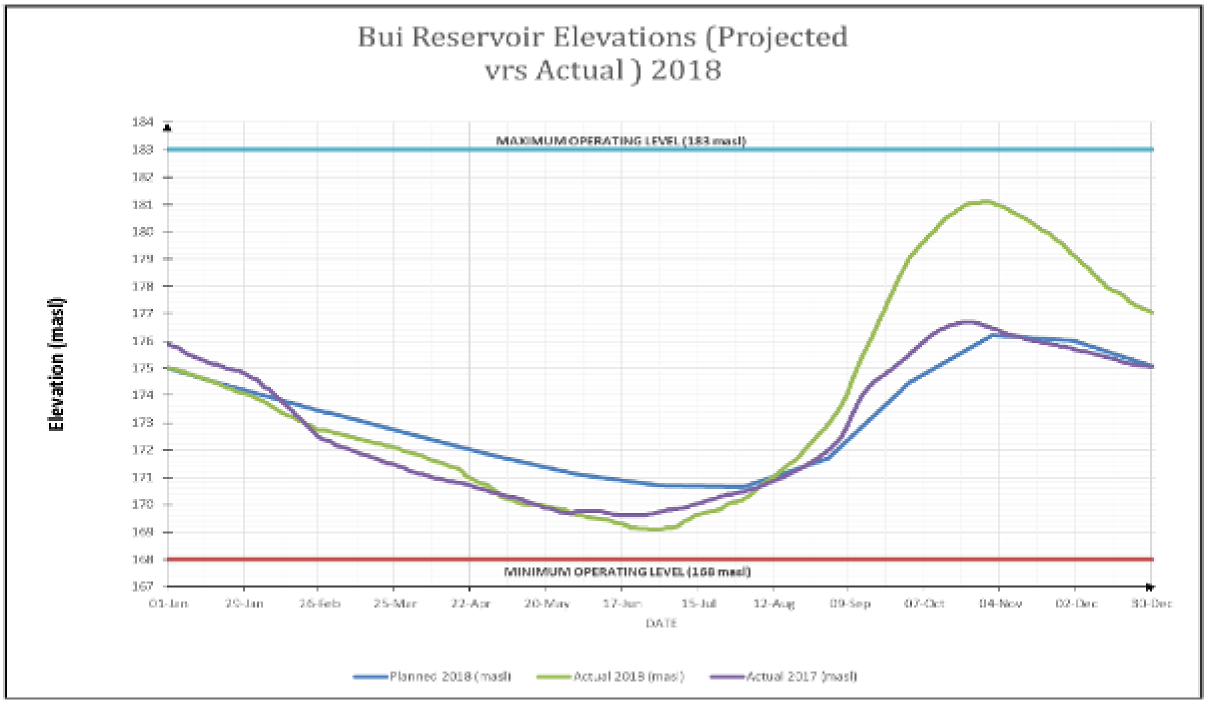
Source: 2019 Annual Supply Plan

At the beginning of 2018, the Bui Reservoir level was 175.01 MASL, dropping to a minimum level of 169.10 MASL at the end of the dry season again as a result of over-drafting of the Lake to make up for the power deficit arising from the shortfall in gas supply from Ghana Gas in the first quarter of 2018. The total energy generated in 2018 was 968.14 GWh compared to the projected of 754 GWh. The higher than projected generation was due to higher than average inflows into the reservoir in the flood season of 2018. At the end of the inflow season, the reservoir level rose to a maximum of 181.10 MASL.

It may be noted that variabilities in inflows due to the impact of climate change could further exacerbate the risks associated with the availability water for hydropower generation.

The projected and recorded reservoir trajectory in 2017 and 2018 is as shown in Figure 8.

Figure 8: Bui Reservoir Elevation 2018



Source: 2019 Annual Supply Plan.

Natural Gas Resource and Infrastructure Constraints

The country currently obtains its natural gas supply from only two sources: (i) imported natural gas from Nigeria through the WAGP, which mainly supplies thermal power plants in the Tema power enclave; and (ii) indigenous natural gas supply[12] .

Despite the large proven gas reserves of Nigeria (estimated at 188.8 TCF[13] as at the end of 2018) with a Reserve/Production ratio of 108.6 years, internal challenges faced by gas suppliers in Nigeria and unpaid bills by VRA constrained natural gas supplies through the West African Gas Pipeline to power plants in Ghana.

[12] Supply of indigenous natural gas in 2018 was from the Jubilee, TEN and Sankofa and Gye Nyame (SGN) fields

[13] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2019-full-report.pdf (Accessed on 19-09-2019)

Ghana's total proven domestic natural gas reserves as at the end of 2016 was estimated at about 2 TCF with only marginal increases between 2017 and 2018 to about 2.1 TCF as at end of 2018.

In 2016, 44.8 TBtu wet natural gas was produced from domestic gas sources (Jubilee and TEN). Natural gas production in 2016 suffered a major setback when the turret bearing of FPSO Kwame Nkrumah began to malfunction in February. This resulted in a 34-day shutdown (from March 31 to May 3, 2016 of the Jubilee Field for maintenance work) and caused a decline of 27% in the production of indigenous gas from Jubilee fields from 52.5 TBtu in 2015 to 38.4 TBtu in 2016. Natural gas production increased by 72.5% to 77.3 TBtu in 2017 with additional gas from the Sankofa and Gye Nyame (SGN) fields. Natural gas production further increased by 18.3% to 91.5 TBtu in 2018.

The total natural gas (lean gas) supplied from WAGP and Atuabo for electricity generation increased by 68% from about 24.0 TBtu in 2016 to 40.0 TBtu in 2017. The total natural gas supplied decreased by 16% to 34.0 TBtu in 2018. Natural gas supplied from domestic sources accounted for 83.3% of the total in 2016, 70.8% in 2017 and 84.3% in 2018 (see Table 8 below).

Table 8 Natural Gas Supplies from WAGP and Atuabo GPP in MMBtu

	2016	2017	2018
WAGP	4,002,683	11,712,897	5,292,410
Atuabo GPP	19,935,000	28,392,000	28,367,151
Total	23,937,683	40,104,897	33,659,561

Source: WAGP – National Energy Statistics and Atuabo – PIAC Annual Reports

The WAGP was originally configured to allow for only 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 and the "take-or-pay" contractual agreement for the supply of natural gas from the SGN fields, 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 centers in the east. This project was completed and became fully operational in August 2019, thus improving the reliability of gas supply to power plants in Tema.

Cost of Fuels for Electricity Generation

Fuel price risk is an important factor in the country's power generation activity as the generation mix shifts towards a prevalence of thermal power generation technology. The cost of electricity generation from fossil fuel based power plants depends to a large extent on the cost of the fuel (e.g., natural gas, LCO, HFO and diesel) used. When the cost of the fuel is low, the price of electricity is cheap; at high fuel prices, electricity prices can be significantly high too. Hence, the high cost of fuels for thermal power generation (thermal power generation technology currently forms a larger proportion in the generation mix), 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 (in real \$2016).

The headline price of delivered gas from Sankofa fields was set at \$9.8/MMBtu in 2019 (this is expected to be lower, due to the lower capital investment costs than was initially anticipated).

The cost of gas from the Jubilee fields for foundation customers is relatively low (at about $2.9/MMBtu in 2016$), but the costs of gas processing and transport increase the delivered cost to above $8/MMBtu. With the inclusion of associated gas from TEN fields and the non-associated gas from Sankofa fields, the weighted average cost of natural gas is about $7.6/MMBtu (in $2016). 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 in March 2019) is about GHp 42.98/kWh[14] (US cents 9.73/kWh), which is the weighted average of the cost of thermal generation of about US cents 18.2/kWh and the cost of hydropower generation of about US cents 3.5/kWh (mostly from Akosombo, Kpong and Bui).

The use of coal and nuclear power for electricity generation are also options to consider to reduce the end-user electricity tariff, if the costs of these technologies are low. However, currently, the estimated capital costs of these technologies are relatively high compared to gas power plants.

Use of Renewable Energy sources for Electricity Generation

The Renewable Energy Act (Act 832) 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. Government of Ghana has also made a commitment under the Paris Agreement to “scale up the penetration of renewable energy by 10% by 2030”[15].

Meeting the RE targets would require significant increase in the deployment of grid-connected renewable energy sources. As at end of first quarter of 2018:

- 113 Provisional Wholesale Electricity Supply Licences had been issued to potential Independent Power Producers (IPPs) who expressed the intent to develop about 6,698 MW of electricity from renewable energy sources.
- 75 of the licences issued were for solar photovoltaic (PV) with a total capacity of about 4,243 MW.
- Of the licenses issued, 35 licensees have obtained Siting Permits, of which 29 were for solar PV.
- Only eight of the licensed companies have been issued Construction Permits to proceed to develop solar PV projects.

VRA is making efforts to install a 12 MW grid-connected solar PV plant at Kaleo and Lawra in addition to the 2.5 MW plant at Navrongo to fulfil its RE obligations. BXC Solar installed and

[14] Composite BGC (VRA and IPPs) effective 15th March 2019

[15] 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

commissioned a 20 MW solar power plant at Winneba in 2016 and another 20 MW solar plant at Onyadze in the Central Region (operated by Meinenergy) in 2018. Bui Power Authority (BPA) has also secured a bid to install up to 250 MW grid-connected solar PV also to fulfil its obligations. This plant is expected to be completed and commissioned in the first quarter of 2020.

Recent feasibility studies have established some potential for electricity generation from wind power along the eastern coast of Ghana, east of the Greenwich Meridian. A number of licenses for the development of wind projects have been issued by the EC. A Construction Permit has also been issued, in 2015, for the development of a 150 MW wind farm project. Some of these projects are in advanced stages of development; however, none of them has yet reached the financial close phase.

Small hydropower, biomass combustion and waste-to-energy plants are dispatchable and have social and environmental benefits; however, they are relatively more expensive.

One key limiting factor for increased grid integration of variable renewable sources, such as solar PV and wind, is the impact of their intermittency on the national grid. GRIDCo and ECG have evaluated the impacts of integrating large utility scale solar PV plants on the grid. The IRRP-NREL Workshop held in October 2017 in Accra noted that operational changes alone are enough to accommodate variable renewable energy capacity of up to 10–15% of the total grid capacity.

Nuclear Option for Power Generation

The country's interest in developing nuclear power for peaceful purposes is to provide secured, clean and reliable baseload power, which stimulates industrial and economic growth and be sufficient for export. It must be noted that its introduction will bring other non-power benefits such as 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.

<u>Nuclear Power for Electricity Generation in Ghana</u>

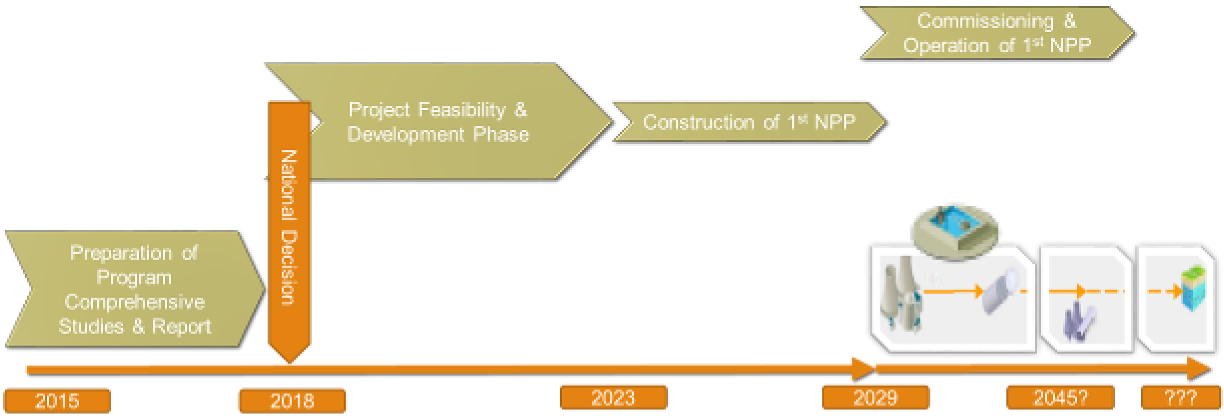
In May 2007, the Government of Ghana set up a Presidential Committee on Nuclear Power (PCNP) to investigate the role of nuclear power for electricity generation in Ghana. Cabinet decision was therefore taken in 2008 to include nuclear power in the national energy mix following the recommendations made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

The efforts made by the country towards the development of nuclear power for peaceful uses from 1960s until 2015 have been thoroughly discussed in the 2018 IPSMP report.

A roadmap for implementation of a Nuclear Power Programme was developed by Nuclear Power Centre (NPC[16]) 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 within 14 years, with 2015 as the base year. This was reviewed by the International Atomic Energy Agency (IAEA) in November 2015 and subsequently approved by the Ghana Nuclear Power Planning Organization (GNPPO). Figure 9 shows the proposed roadmap for the construction of the first nuclear power plant in the country.

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

Figure 9: Nuclear Power Roadmap for Ghana



Source: Ministry of Energy, 2016.

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 such as the state-owned nuclear institutions in Russia and China to foster cooperation.

Nuclear power plants are expensive to build but relatively cheap to operate because of the low variable cost component. For example, the capital cost of a 1200 MW plant could be about US $5–$6 billion[17], which is a significant investment. 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. Consequently, under certain circumstances, nuclear energy can be competitive when compared with fossil fuels as a means of electricity generation. Hence, if the country were unable to develop a long-term supply of low cost indigenous natural gas resources due to economic or geological limitations and challenges, then nuclear power would become an attractive and competitive option in the long-term. 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.

According to International Atomic Energy Agency guidelines, any country seeking to move onto phase two of a nuclear power programme must have in place a government agency, a regulator and an owner operator. In Ghana, the government agency in place is the Ghana Nuclear Power Programme Organisation (GNPPO), and the regulator is the Nuclear Regulatory Authority (NRA), which were established in 2012 and 2016 respectively. In January 2019, an owner operator – the Nuclear Power Ghana was established to complete phase one of the

[17] Adombila, Maxwell Akalaare "Ghana goes nuclear; 2 Plants in six years." *Graphic Online*. 15 May 2018. https://www.graphic.com.gh/news/general-news/ghana-goes-nuclear-2-plants-in-six-years.html (accessed 06 June 2018).

implementation of the nuclear power programme in the country. The country is expected to embark onto phase two of the nuclear power programme in 2020.

The greatest challenge in the pursuit of nuclear power programme would be funding and financing of the country's nuclear power programme. A number of financing models have been developed for funding new reactors that are currently under construction worldwide. This include: (i) solely Government, (ii) joint Government and Vendor, (ii) joint Government and private sector, (iv) combined Government and corporate finance, and (v) solely corporate finance[18]. The GoG has opted for a joint government and vendor-financing model to finance the country's nuclear power plant[19].

Coal Option for Power Generation

After the 2006/07 power supply crisis, the Government of Ghana reviewed its policy to include a consideration of nuclear energy and coal power generation in the national electricity generation mix for the future. The 2010 National Energy Policy document therefore called for evaluating the role of coal in the future fuel supply mix for electricity generation in Ghana.

Further, the disruption to the supply of gas from Nigeria in 2012 brought to the fore the need for alternative fuel supply options including coal, to assure energy supply security. VRA and the Shenzhen Energy Group (SEG) of China signed a Memorandum of Understanding (MoU) in September 2014 to evaluate a potential coal power generation option for Ghana. Under this MoU, a pre-feasibility and full feasibility studies were undertaken and completed the same year and the reports were presented to key stakeholders for review and feedback on the way forward. The studies recommended the development of a plan to implement a 4 x 350 MW supercritical coal-fired plant in Ghana to come online in 2018. The project was expected to be implemented in two 2x350 MW phases together with the affiliated Coal Handling Terminal (CHT) at Ekumfi Aboano in the Ekumfi District of Central Region. The total cost of the 4 x 350 MW project was estimated to be about US $1.5 billion, which would be provided by the China-Africa Development Fund.

The proposed coal plant project has stalled due to:

- Public agitation about the adverse potential environmental effects of the coal power plant.
- The issue of burning of coal undermining the country's commitment to the Paris Agreement.20
- The current (as at 2019) 'excess power generation' capacity position as compared to power demand

[18] Barkatullah, Nadira and Ahmad, Ali. "Current status and emerging trends in financing nuclear power projects." *Energy Strategy Reviews*. 18 (2017) 127e140. https://website.aub.edu.lb/ifi/programs/eps/Documents/articles/20171003_current_status_financing_nuclear_power_ali_ahmad.pdf (accessed on 06 July 2018).
[19] Adombila, Maxwell Akalaare "Ghana goes nuclear; 2 Plants in six years." *Graphic Online*. 15 May 2018. https://www.graphic.com.gh/news/general-news/ghana-goes-nuclear-2-plants-in-six-years.html (accessed 06 June 2018).
[20] "Ghana is not building a coal plant – Minister." *Ghana Business News*. 10 October 2016. https://www.ghanabusinessnews.com/2016/10/10/ghana-is-not-building-a-coal-plant-minister/ (accessed 21 June 2018).

- Availability of indigenous natural gas volumes and the potential for new finds at lower gas cost

The supercritical and ultra-supercritical technologies are part of the high-efficiency low-emission coal power technologies that operate at increasingly higher temperatures and pressures and therefore achieve higher efficiencies of about 42–45% (LHV) than conventional Pulverized Coal Combustion (PCC) units with efficiencies of 33–38% (LHV).21

The capital costs of supercritical technologies are about 10–30% higher than the conventional coal plants.22 However, the higher costs may be partially or wholly offset by fuel savings, depending on the price of fuel.

Thus, the planning for any potential coal plant in Ghana must consider or overcome the following challenges:

- Demand growth
- Potential availability of low cost natural gas
- Financing the high investment costs (including the high port development costs for handling of coal) and
- The energy security implications of importing significant volumes of fuel annually.

However, the high port development costs for handling of coal may be borne by the government to bring down the investment cost. For coal power plants, potential financing sources include development finance institutions (DFI) and Asian finance sources.23

3.2.4. 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 to reduce losses. The challenge in the past and at present is how to obtain the sufficient investments in a timely manner to ensure that expansion and upgrade of the network (e.g., A4BSP), and additional lines to Kumasi and Bolgatanga 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. It is hoped that the implementation of the ESRP would help to address the financial challenges in the energy sector and delays in project implementation.

[21] International Energy Agency. 2012. *Technology Roadmap – High-Efficiency, Low-Emissions Coal-Fired Power Generation*. https://webstore.iea.org/technology-roadmap-high-efficiency-low-emissions-coal-fired-power-generation (accessed 06 July 2018).

[22] Ibid.

[23] http://www.ee.co.za/article/clean-coal-high-efficiency-low-emissions-technology-leads-way.html (accessed 06 July 2018).

Table 9: Transmission and Distribution Losses in Ghana

Indicator	Source	Unit	2013	2014	2015	2016	2017	2018
ECG Aggregate Technical, Commercial Losses	ECG	%	23.4	25.2	22.7	23.6	22.6	24.3
NEDCo Aggregate Technical, Commercial Losses	NEDCo	%	21.3	24.0	29.0	31.1	27.4	31.0
EPC Aggregate Technical & Commercial Losses	EPC	%			6.4	7.2	1.8	2.7
GRIDCo Transmission Losses	GRIDCo	%	4.4	4.3	3.4	4.4	3.8	4.4

Source: EC 2019 Energy Statistics.

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/PDS 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 23% in 2018, costing USD 400 million annually. With the transition of distribution system operator from ECG to PDS Ghana on March 1 2019, it is anticipated that the KPIs agreed under the Concession Agreements will lead to improved operational efficiency[24].

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.

3.2.5. 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

[24] Energy Sector Recovery Plan, 2019

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, 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.

The establishment and implementation of the WEM, and 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. Background

The Integrated Resource and Resilience Planning (IRRP) Technical Committee, headed by the Energy Commission (EC), selected the Integrated Planning Model (IPM®)[25] as the optimisation tool for Ghana's Integrated Power Sector Master Plan (IPSMP) study, after the assessment of a number of power system planning tools.[26] The model was expected to produce an optimised generation capacity expansion plan to meet the forecasted electricity demand at the least cost, taking into consideration specific operational and contractual constraints.

A variety of tools are available for power system planning, and each tool is designed for certain planning tasks, such as:

- Expansion planning and policy analysis
- Production costing
- Transmission power flow
- Distribution power flow
- Reliability

Each tool within each category also has its own capabilities and strengths. In general, for the IPSMP, the focus of the expansion planning software tools can be used to determine a system investment plan, along with other key outputs, as noted in the adjacent box.

Expected Outputs from Expansion Planning Optimization Models

- Least-cost resource expansion plan
- Capital investment requirements
- Present value of system costs (net present value [NPV] of revenue requirements)
- Expected system dispatch
- Fuel expenditures and requirements
- Wholesale power prices
- Amount (and costs) of unserved energy
- Emissions profiles
- Import/export quantities

Table 10 shows an illustrative list of power system planning tools considered by the Technical Committee at the beginning of the IRRP project. These tools are generally categorised along their planning functions, although many tools can be used for multiple purposes. As discussed in the Final 2018 IPSMP report, the tools in the red box in Table 10 were initially considered most relevant for the IPSMP since they allow for the optimisation of generation and transmission capacity expansion strategies and policy/scenario analysis.

The IRRP team then further reviewed the planning tools and short-listed several modelling tools (in bold) based on their applicability for the Ghana IPSMP study. The models were evaluated for the following attributes:

- Expansion capability
- Ability to capture zonal differences
- Environmental constraint modelling
- License fees
- Technical and user support

The results from the Ghana-IPM (GH-IPM) model form the basis for the Ghana IPSMP's Least-Regrets Strategy review and provide an opportunity to understand the implications of

[25] IPM has been used and continually developed for over 35 years and is being used in the U.S., Europe, Africa, and Asia.

[26] Note, each tool reviewed had its own capabilities, strengths, and weaknesses.

policies and decisions, as well as provide an option to explore possibilities for, and implications of, planning decisions.

Table 10: Illustrative List of Modelling Types and Tools

Reliability	Distribution Power Flow	Power Flow	Production Costing	Expansion Planning & Policy Analysis
MARS	CYMDIST	POWERWORLD	DAYZER	AURORA
REFLEX	EDGE	PSAT	GRIDVIEW	BALMOREL
SERVM	GRIDLABD	PSLF	MAPS	**CAPACITY EXPANSION (ABB)**
SRAM	OPEN DSS	**PSSE**	PCLOUDANALYTICS	EGEAS
TRELLS			PROMOD	**IPM**
				LEAP
				MESSAGE
				NEEM
				NEMS
				PLEXOS
				REEDS
				SDDP & OPTGEN
				UPLAN NPM
				WASP

Most applicable to IRRP

4.2. IPM OVERVIEW

IPM 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.

4.2.1. 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 10 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 2019 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.

4.3. MODEL STRUCTURE AND FORMULATION

The IPM model structure and the 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, the decision variable and the the set of linear constraints.

4.3.1. Objective Function

Objective Function for the Integrated Planning Model (IPM®)

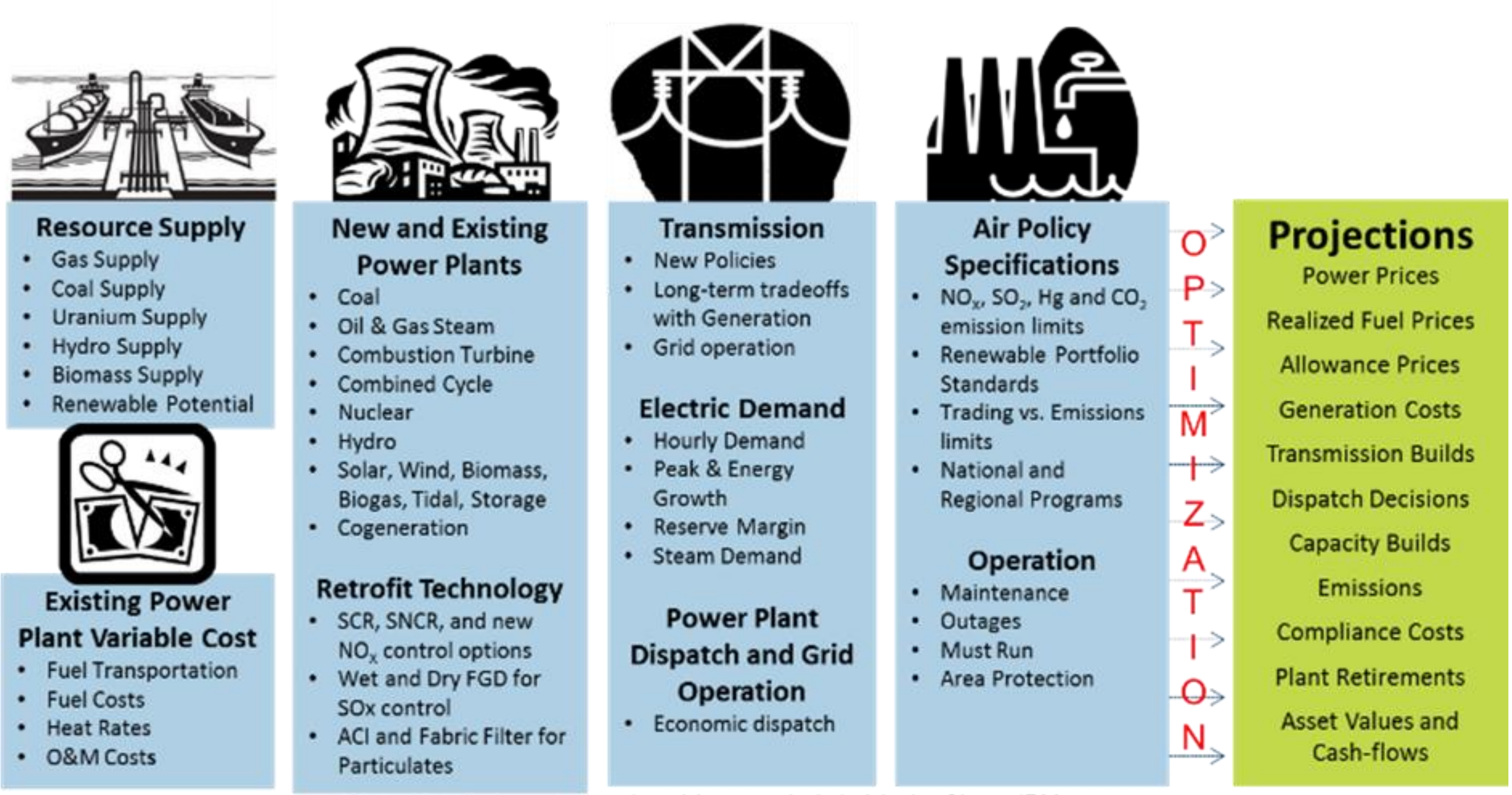
Minimize the present value of:

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

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.)

Figure 10: Framework for Ghana Integrated Planning Model (IPM)



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

IPM's primarily 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.[27]

4.3.2. 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 is 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: This decision variables depicts the generation from each of the model power plant, with each of them , having respective generation decision variable defined for all possible combination 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's 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 variables characterises the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. The decision variables represents 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.

4.3.3. Constraints

The constraint in the *GH-IPM 2019v1* 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

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

4.4. 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 2019v1*.

4.4.1. 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 plants that are already in operation in the country. For the *GH-IPM 2019v1*, all existing plants as of August 2019, totalling 19, were characterised. The total number of units within these plants is 153. For the *GH-IPM 2019v1,* 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 2019v1*, only the five power plants that were physically under construction were categorised as firmly planned. The generation units of these plants were aggregated, similar to the existing units.

Retrofit and Retirement Options: IPM uses model plants to as retrofit and retirement options for existing and firmly planned units. However, this capability of IPM was not utilised in the *GH-IPM 2019v1 version*—although it expected to be included in the 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 2019v1* version.

4.4.2. 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 results reports outputs for only model run years, IPM includes the costs in all years in the planning horizon in the cost minimization problem.

4.4.3. Cost Accounting

The cost components considered by the model include the costs of investing in new capacity options, fuel costs, 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 levelised 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.

4.4.4. 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;[28] however, because it is a wholesale model, it does not reflect retail distribution costs. However, generation is based on net energy for load,[29] as opposed to delivered sales,[30] 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.

4.4.5. 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 2019v1* has used months as seasons, and so every year has 12 LDCs.** Figure 11 presents a chronological hourly load

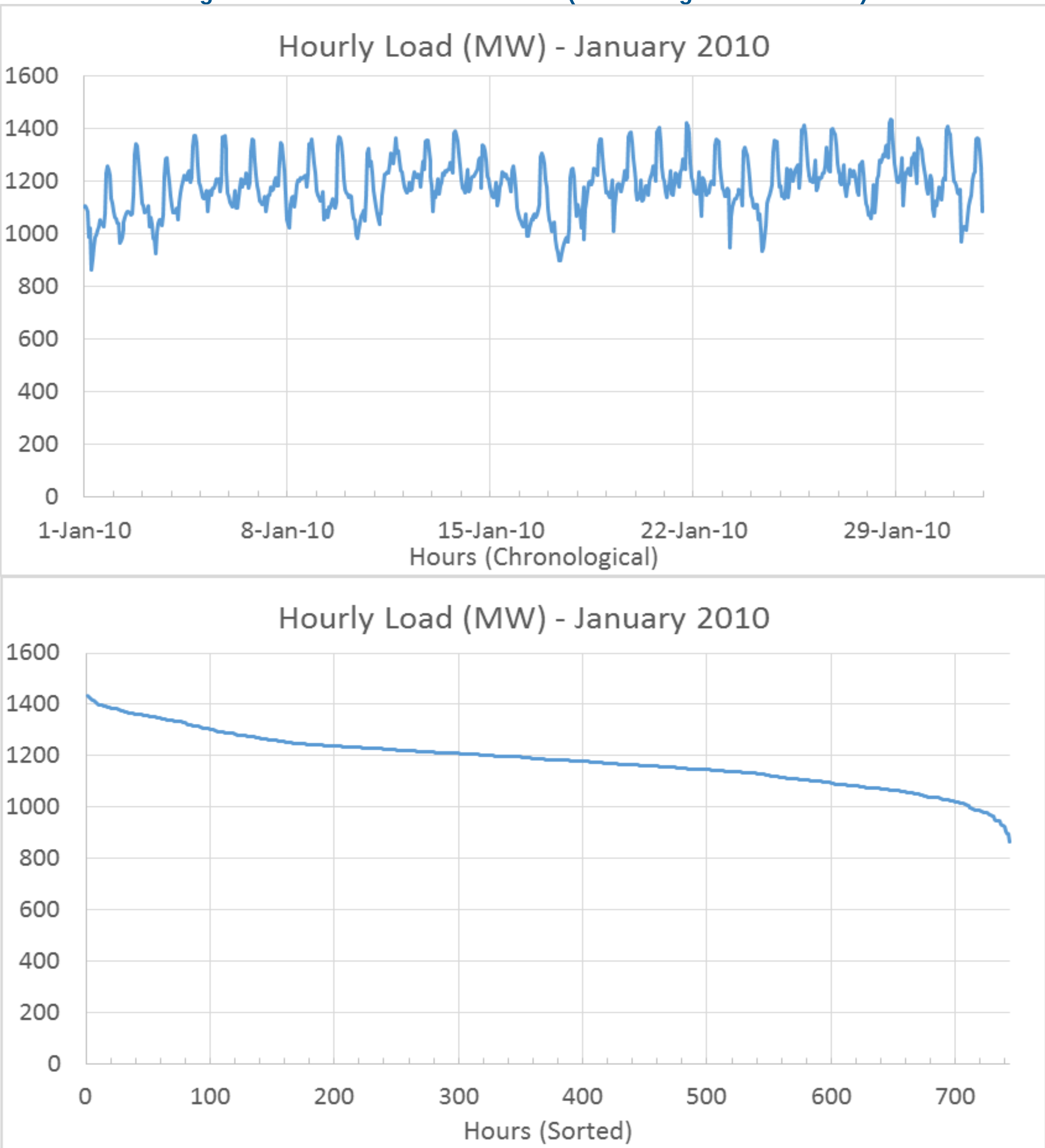
[28] The current version of the Ghana-IPM model does not include any transmission costs or losses between the various model zones. Instead, the losses are included as "demand" on the grid that needs to be met.

[29] 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.

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

curve for the month of January 2010 and a corresponding LDC for that month consisting of 744 hours.

Figure 11: Illustrative Load Curves (Chronological and Sorted)



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).

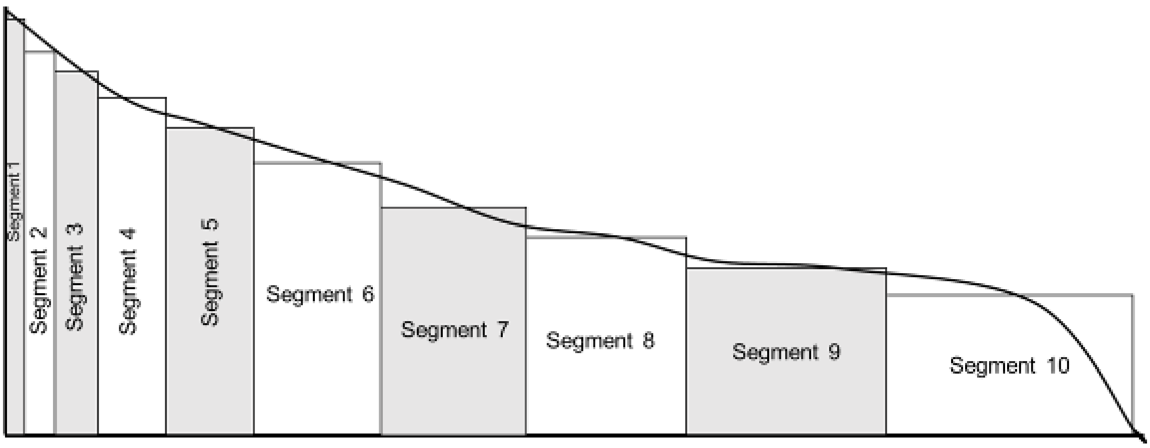
Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 12. ***GH-IPM 2019v1* uses 10 load segments in its seasonal LDCs for model run years 2019–2040.** Therefore, every year has 120 load segments (12 months x 10 segments). Figure 12 illustrates 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 12 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 varies between seasons.

Figure 12: Representation of Load Duration Curve Used in *GH-IPM 2019v1*



4.4.6. 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 13: Hypothetical Dispatch Order in *GH-IPM 2019v1*

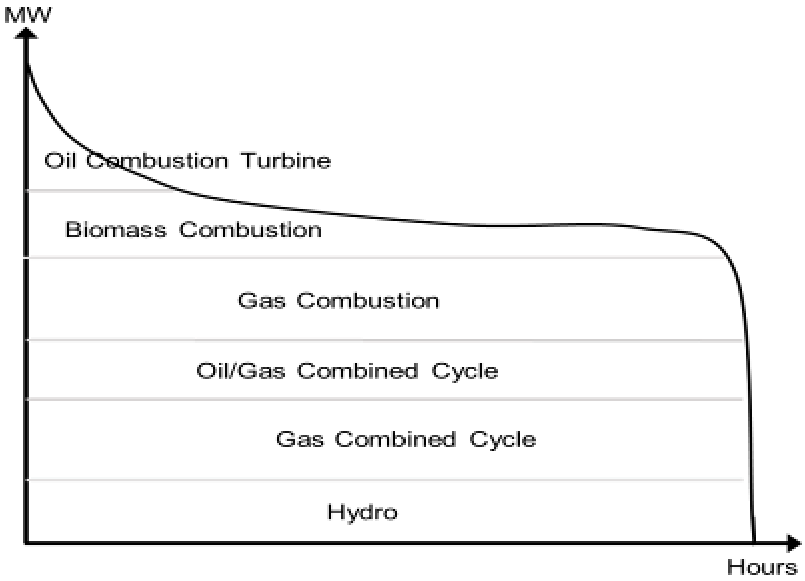


Figure 13 depicts a highly stylised dispatch order based on the variable cost of generation of the resource options included in the *GH-IPM 2019v1*. This shows a hypothetical LDCs with those units with the lowest operating cost being dispatched first for the maximum possible number of hours represented 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.

4.4.7. 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.

4.4.8. 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 2019v1*, 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.**

4.4.9. 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.

4.4.10. 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.

4.5. Data Parameters for Model Inputs and Outputs

4.5.1. 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

4.5.2. 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 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, which 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,[31] and NorthGH (see Figure 14).

The demarcation of the grid system into four zones for the IPM modelling is an update to the demarcation used in the 2011 GRIDCo Transmission Master Plan, which had five zones. The change from five zones to four is due to the transmission upgrades that were implemented in the NEDCo distribution region, following: (i) the commissioning of Bui hydropower plant and its associated transmission lines; and (ii) the completion of the transmission loop in Upper West region of the country. These two system upgrades, therefore, eliminated the need to maintain a separate zone for Brong Ahafo.

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 Brong Ahafo, Northern, Upper East, and Upper West regions.

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

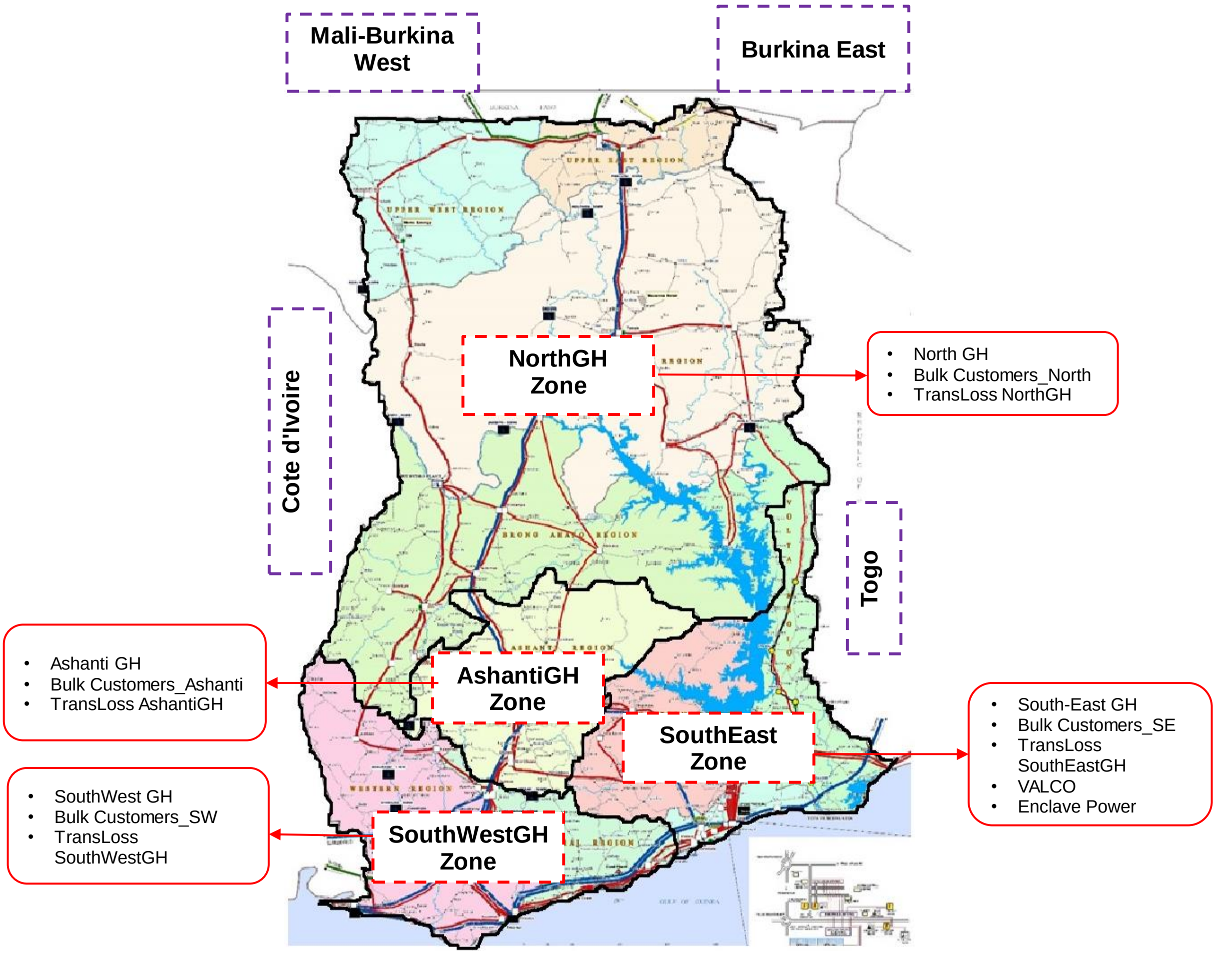
Table 11: Description of Ghana Model Zones and Regions

Ghana Zone	Model Region	Geographical/Demand Coverage
SouthEastGH	SouthEastGH	ECG – Volta, Greater Accra and Eastern operational regions
	BulkCust – SouthEastGH	Non-ECG bulk customers in Volta, Greater Accra & Eastern regions
	EPC	Free Zones Enclave in Tema
	VALCO	VALCO plant in Tema
SouthWestGH	SouthWestGH	ECG – Central and Western operational regions
	BulkCust – SouthWestGH	Mines and other direct customers in Central & 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 Brong Ahafo, Northern, Upper East and Upper West regions
	BulkCust – North GH	Mines and other direct customers in NEDCo territory

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

Ghana Zone	Model Region	Geographical/Demand Coverage
Togo	Togo	Power exchange with Southern and Northern Togo
Cote d'Ivoire	Cote d'Ivoire	Power exchange with Cote d'Ivoire
Mali-Burkina	Burkina East	Power exchange with Ouagadougou, Burkina Faso
	Mali-Burkina West	Power exchange with Bobodilassou (Burkina) and Bamako (Mali)

Figure 14: Ghana Zones and Modelling Regions



Source: IRRP Project, based on GRIDCo transmission map.

5.2. High Level Assumptions

5.2.1. Run Years and Mapping

As discussed in section 4.4.2, 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 12. 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 2019, 2020, 2021, 2022, 2023, 2024, 2025, 2026, 2027, 2028, 2029, 2030, 2035, and 2040.

The analysis time horizon for GH IPM 2019 v.1 extends from 2019 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 is shown in Table 12.

Furthermore, the *GH-IPM 2019v1* 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 4.4.5.

Table 12: Year Map used in *GH-IPM 2019v1*

Run Year	Years Represented	Number of Years
2019	2019	1
2020	2020	1
2021	2021	1
2022	2022	1
2023	2023	1
2024	2024	1
2025	2025	1
2026	2026	1
2027	2027	1
2028	2028	1
2029	2029	1
2030	2030-2032	3
2035	2033-2037	5
2040	2038-2040	3

5.2.2. Financial Assumptions

In terms of cost calculation, the GH IPM 2019 v.1 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 10% for the *GH-IPM 2019v1* model**, and is based on the real weighted average cost of capital (WACC).[32] WACC for all future

[32] 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

power plants is different, based on specific assumptions about debt-to-equity ratios, and the loan interest rate and rate of return on equity. This is a key difference between the 2018 IPSMP and. the 2019 IPSMP modelling.

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.[33] In *GH-IPM 2019 v1* model, there a 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 on the discount rate and CCR for different types of new power plants and transmission lines.

Table 13: Changes to Financial Assumptions for New Power Plants

2018 version – All Technologies had same Capital Charge Rates

Technology	Lifetime (yr)	Equity Rate	Equity Ratio	Debt Rate	Debt Life (yr)	Real CCR
All technologies	30	0.18	0.3		20	10.8%

2019 version – Technology-dependent Capital Charge Rates

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 by Ghana's power sector utilities and

[33] 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

the EC. 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. As part of this process, long-term load forecast reports are published by the utilities, and usually cover a period of about 10 years. These reports are updated annually based on revised and updated underlying assumptions.

The EC, on the other hand, uses a bottom-up methodology based on the Long-Range Energy Alternatives Planning (LEAP) model to develop an indicative demand forecast. This bottom-up methodology uses end-use survey data (technologies, consumption patterns, etc.) to project "potential demand", i.e., the demand if techno-economic constraints are removed. While the utilities update their forecasts regularly, the EC update of the indicative demand is developed over a longer period (5–10 years).

For the purpose of the IPSMP demand forecasts, reports of existing load forecast reports were collected and reviewed to assess their adequacy for the IPSMP. The rationale for the exercise was to review existing work and evaluate what further analysis was needed. The review process was guided through interactions with key technical staff of the various utilities as well as the Steering and Technical Committees. Detailed information about the review exercise is provided in the Appendix.

The IPSMP Reference Case electricity demand forecast relied on an econometric methodology to forecast annual peak and energy demand for ECG and NEDCo, based on the approach taken by these utilities already. For both of the utilities, a log-log linear regression model was developed based on historical annual GDP (in real 2006 Ghana Cedis) as the only independent variable, [34] and historical annual electricity consumption in GWh as the dependent variable.[35] The historical electricity consumption was estimated to be the metered electricity sales as measured by the utilities plus one-half of total distribution losses—because half of the measured losses were assumed to be commercial losses (i.e., electricity consumed but not included as sales). The other half of the losses were assumed to be technical losses. For the regressions, annual data from 2000 to 2014 was included for both ECG and NEDCo.

The regression for both ECG and NEDCo of the historical consumption (i.e., sales plus one-half of losses) was highly correlated with annual real GDP in Ghana cedis (GHS), with R^2 for ECG at 0.9922 and R^2 NEDCO at 0.9914.

The log-log linear regression equations for ECG and NEDCo were used to develop the projected ECG and NEDCo sales in the future based on projected GDP from 2017 to 2040. For 2015 and 2016, actual annual real GDP was used based on data from the Ghana Statistical Survey. Estimates of Ghana's GDP growth rate in the International Monetary Fund's October 2016 Ghana Country Data report was used to determine the GDP from 2017 to 2021. Beyond 2021, a 5-year rolling average of the real GDP growth rate projections from IMF was

[34] Both ECG and NEDCO use a number of different variables for their forecasts; however, several such variables were found to be correlated with each other and not statistically significant.

[35] The historical electricity consumption data from ECG and NEDCo excludes consumption due to captive generation by end users.

used to forecast the real GDP values until 2040. This GDP forecast from 2017 to 2040 was then used to calculate the ECG and NEDCo future sales up to 2040, based on the respective regression equations.

The future ECG and NEDCo sales were converted to purchases of electricity from GRIDCo from 2015 to 2040 by adding the respective projected technical losses on top of the sales. Future ECG technical losses were assumed to decrease from 11.5% in 2016[36] to 7% in 2030.[37] As per the ECG 2015 report (Electricity Company of Ghana Ltd., 2015), ECG projects that its total distribution losses (technical and commercial) would decrease from about 23% in 2016 to about 15% in 2024. ECG's distribution losses were assumed to decrease further to about 12% by 2030. Similarly, NEDCo's technical losses were assumed to decrease from about 19% in 2016 to 13% in 2030. NEDCo projects, however, that its total distribution system losses (technical and commercial) would remain at 20% from 2016 to 2024 according to its 2015 long-term forecast.

The annual future energy purchases from the grid for ECG's operational area were split among the modelling zones, based on expected ratios among the zones, as determined by ECG in its 2016 demand forecast report (Electricity Company of Ghana Ltd., 2016). 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 the GRIDCo 2014 Supply Plan with updates received from GRIDCo's bulk customers who are directly connected to the transmission grid.[38] Finally, the transmission losses for each IPM model zone were determined based on outputs of PSS/E analysis, and added to the projected demand for each IPM model zone. Details of the transmission analysis can be found in the Appendix (Volume 3).

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

The expected projections for VALCo's energy and peak demand were determined in discussions with the Ministry of Energy, and are as shown in Table 14. The utilization of two out of VALCo's six potlines has been assumed for the entire planning horizon due to prevailing conditions at VALCO; however, these assumptions can regularly be updated to reflect actual and/or realistic changes.

---

[36] The total loss in 2016 was 23%, but as noted earlier, only half were assumed to be technical losses, with the other half being included as part of the historical consumption that was used for the regression.

[37] This decrease was based on ECG's expectation of improvement in loss reduction over time, as per the ECG 2016 load forecast report.

[38] Note that the demand for ECG and NEDCo's bulk customers and SLT customers is already included in their demand projections.

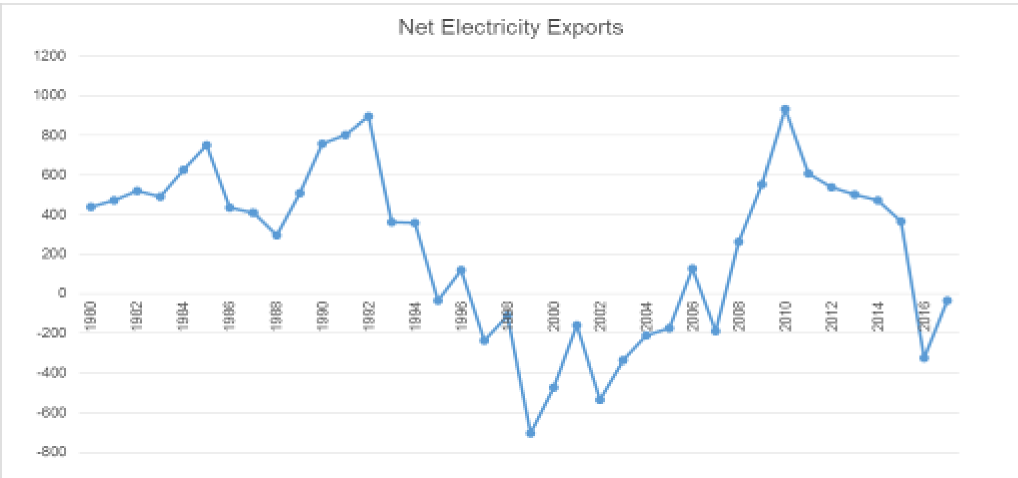
Table 14: VALCO Peak and Energy Forecast

Year	VALCO Forecast	
	MW	GWh
2019	147	1248
2020	147	1248
2021	147	1248
2022	147	1248
2022	147	1248
2023	147	1248
2024	147	1248
↓	↓	↓
2040	147	1248

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. The transaction between the 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 15, although during periods of generation deficiencies, Ghana has been a net importer.

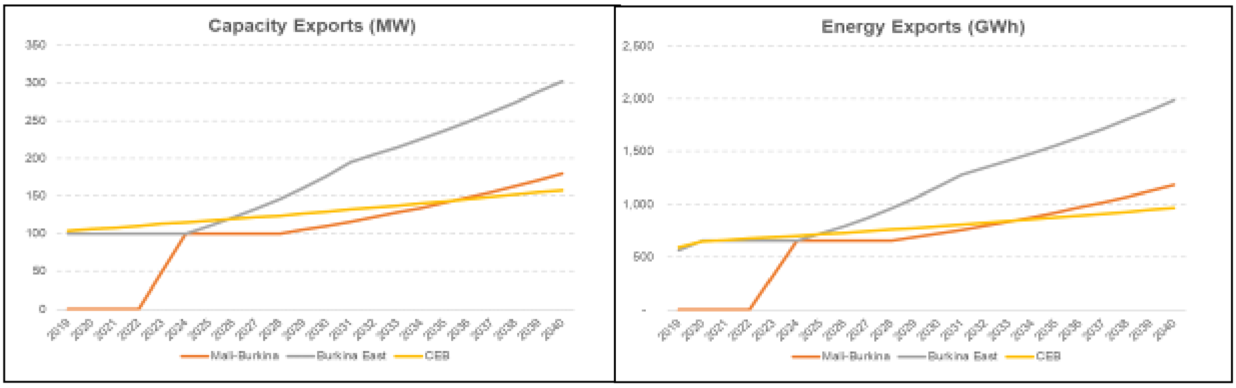
Figure 15: Historical Ghana Net Exports



Source: GRIDCo Transmission Master Plan, 2011.

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 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 Reference Case exports is shown in Figure 16.

Figure 16: 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 1,170 GWh in 2019 to about 3,400 GWh in 2035; and is expected to rise slowly to about 4,100 GWh in 2040. A similar trend is observed in the peak demand exports, which are expected to rise from about 210 MW in 2019 to about 650 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 15 and Table 16 illustrate the Reference Case IPSMP energy and peak demand forecasts, respectively, for the different sectors.

Figure 17 shows a comparison of the energy demand forecasts by the various institutions for the Ghana domestic sector with the IPSMP forecast, and Figure 18 shows the energy demand including demand for VALCO and exports. Figure 19 and Figure 20 compare the projected IPSMP peak demand forecasts with previous forecasts and actual peak demand. These comparisons **do not** reflect any judgements as to which forecasts are right or wrong, but only intend to illustrate the extent of variation in forecasts based on the differences in methodologies (e.g., EC uses a bottom-up end-use methodology, whereas all forecasts rely on regression methods) and inputs (GDP forecasts from different sources and timeframes). Figure 21 compares the GDP growth rate assumptions used in the various load forecast reports and for the IPSMP Reference Case forecast.

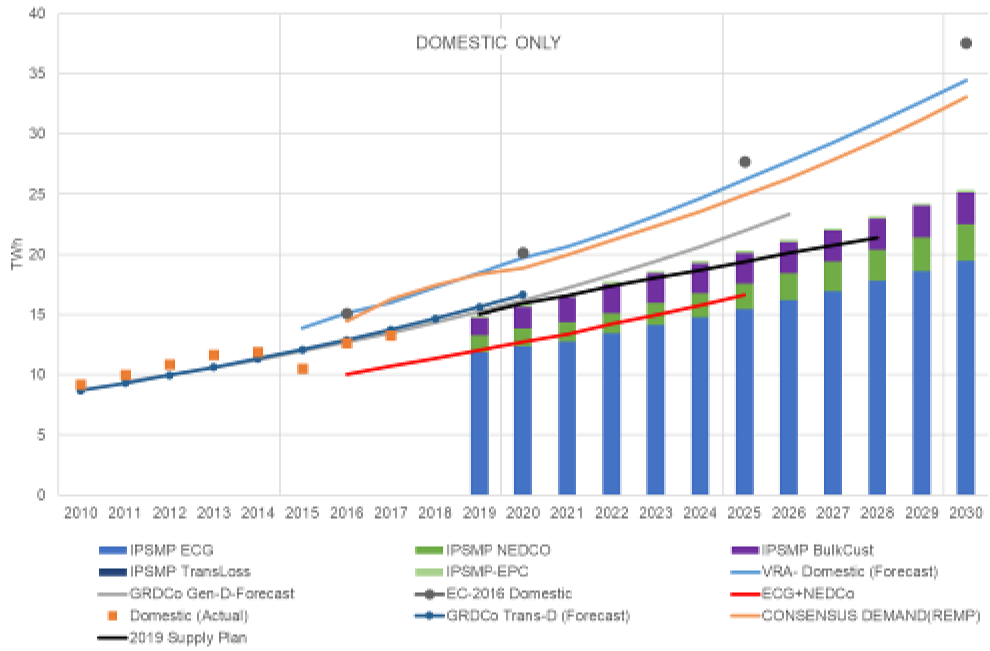
Table 15: Energy Demand Forecast

SUMMARY Annual Wholesale Generation Requirement [GWh]									
Year	ECG	NEDCo	EPC	Bulk Customers	VALCO	Exports	GRIDCO Trans Loss	Total Ghana	Total Domestic Ghana
2019	11833	1444	200	1412	1284	1168	759	18100	14889
2020	12334	1498	179	1816	1284	1318	744	19173	15827
2021	12766	1594	184	2064	1284	1331	792	20016	16609
2022	13435	1699	198	2390	1284	1344	890	21240	17721
2023	14119	1826	205	2467	1284	1687	984	22572	18617
2024	14787	1962	208	2499	1284	2028	632	23400	19456
2025	15462	2109	211	2526	1284	2108	703	24402	20307
2026	16178	2266	213	2563	1284	2195	773	25472	21220
2027	16963	2435	213	2563	1284	2288	821	26568	22175
2028	17774	2617	213	2572	1284	2391	889	27741	23176
2029	18612	2812	213	2604	1284	2536	930	28991	24242
2030	19488	3022	213	2636	1284	2691	972	30307	25361
2031	20465	3248	213	2669	1284	2860	1018	31758	26596
2032	21495	3491	213	2702	1284	2978	1065	33229	27901
2033	22573	3751	213	2736	1284	3103	1115	34775	29273
2034	23703	4031	213	2769	1284	3231	1167	36399	30717
2035	24890	4332	213	2804	1284	3366	1222	38112	32240
2036	26138	4656	213	2838	1284	3508	1280	39918	33846
2037	27449	5003	213	2874	1284	3656	1341	41821	35540
2038	28825	5377	213	2909	1284	3811	1405	43825	37325
2039	30270	5779	213	2945	1284	3974	1473	45938	39207
2040	31787	6210	213	2982	1284	4143	1544	48163	41192

Table 16: Peak Demand Forecast

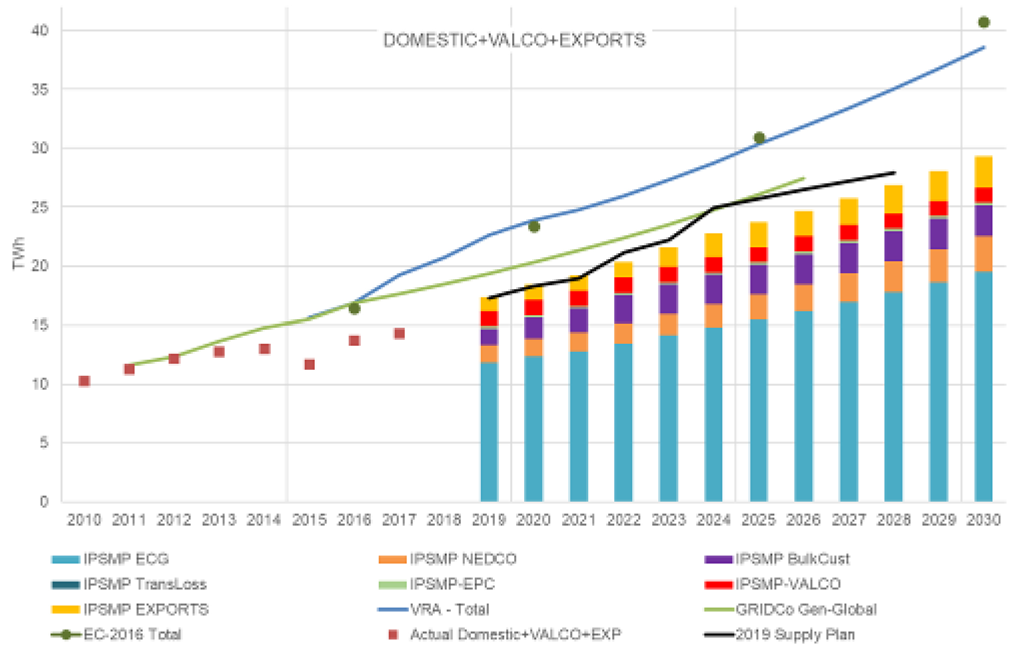
SUMMARY Annual Zonal-Coincident Peak Wholesale Demand Requirement [MW]								
Year	ECG	NEDCo	EPC	Bulk Customers	VALCO	Exports	GRIDCO Trans Loss	Total Ghana
2019	1,801	241	44	253	147	207	136	2,829
2020	1,877	249	39	281	147	209	140	2,942
2021	1,943	260	41	307	147	211	139	3,048
2022	2,045	265	45	352	147	213	164	3,230
2023	2,149	285	48	359	147	266	181	3,434
2024	2,251	306	49	364	147	318	124	3,558
2025	2,353	329	50	364	147	330	136	3,709
2026	2,462	353	51	369	147	344	147	3,873
2027	2,582	380	53	368	147	358	155	4,043
2028	2,705	408	56	369	147	373	168	4,226
2029	2,833	439	56	374	147	396	176	4,420
2030	2,966	471	56	378	147	419	184	4,622
2031	3,115	507	56	383	147	446	193	4,846
2032	3,272	544	56	388	147	465	202	5,073
2033	3,436	585	56	392	147	483	211	5,310
2034	3,608	629	56	397	147	503	221	5,560
2035	3,788	676	56	402	147	524	232	5,824
2036	3,978	726	56	407	147	546	243	6,103
2037	4,178	780	56	412	147	568	254	6,395
2038	4,387	839	56	417	147	592	266	6,704
2039	4,607	901	56	422	147	617	279	7,030
2040	4,838	969	56	428	147	643	293	7,373

Figure 17: Comparison of Ghana Domestic Electricity Demand Forecasts



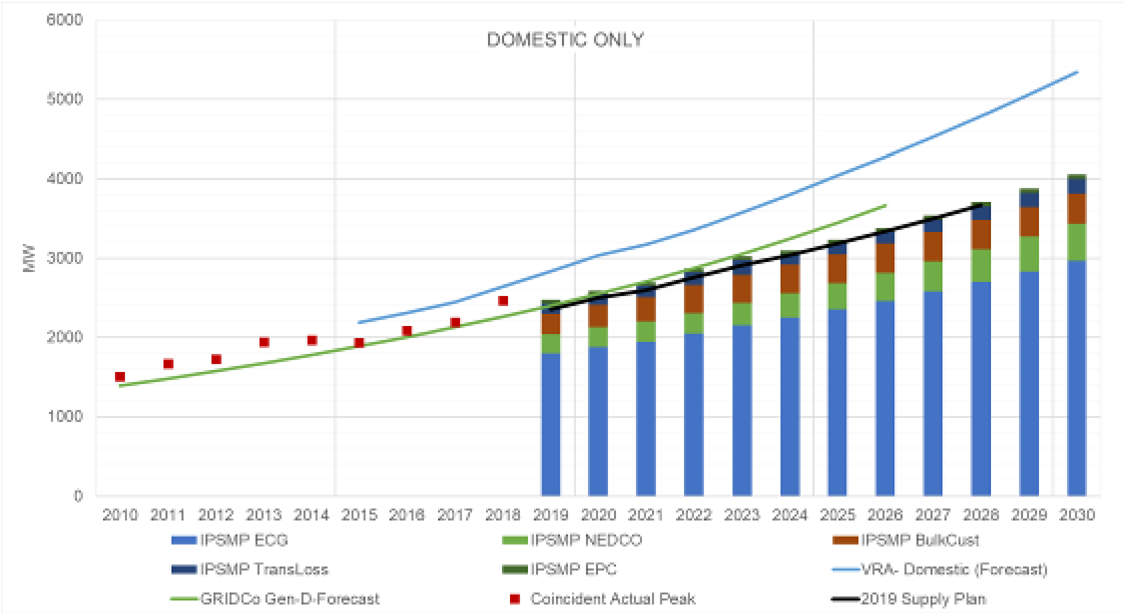
Source: IRRP Project.

Figure 18: Comparison of Total Ghana Electricity Demand Forecasts



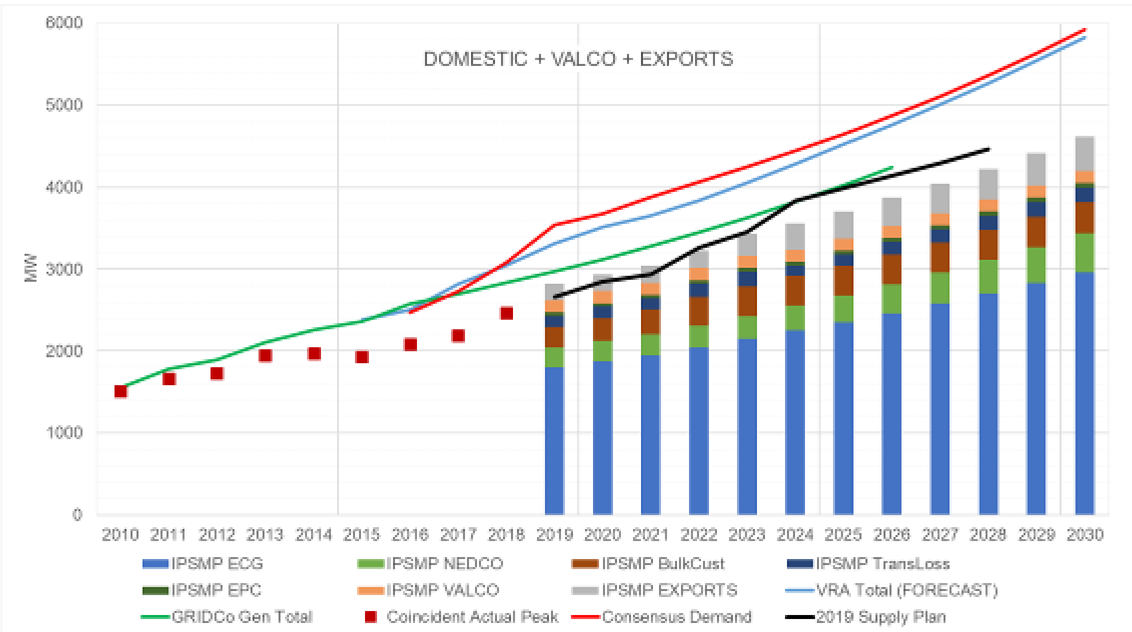
Source: IRRP Project.

Figure 19: Comparison of Ghana Domestic Peak Demand Forecasts



Source: IRRP Project.

Figure 20: Comparison of Total Ghana Peak Demand Forecasts



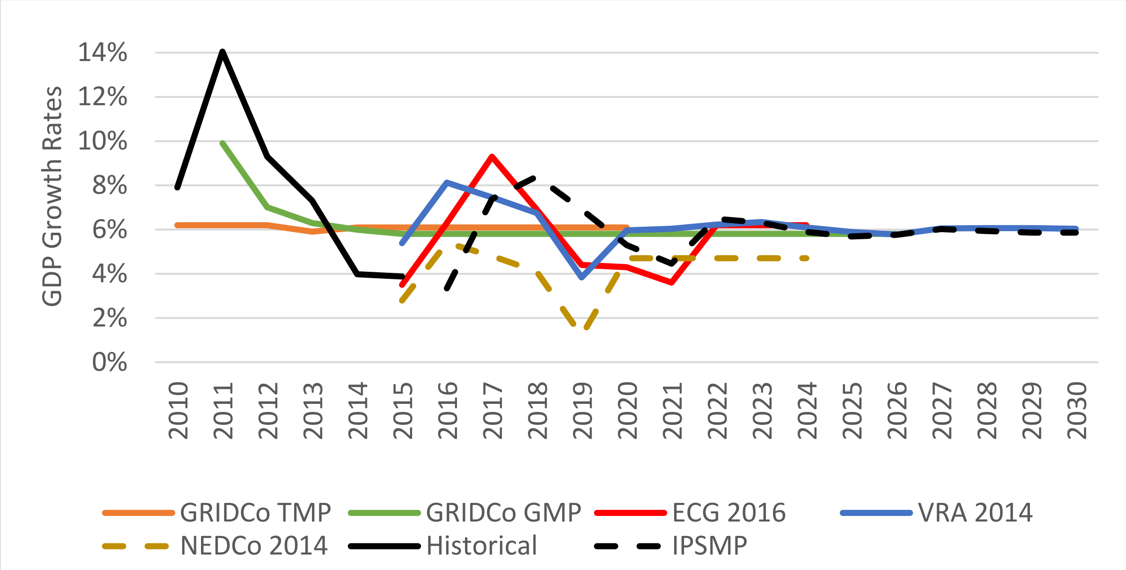
Source: IRRP Project.

5.3.1. 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.

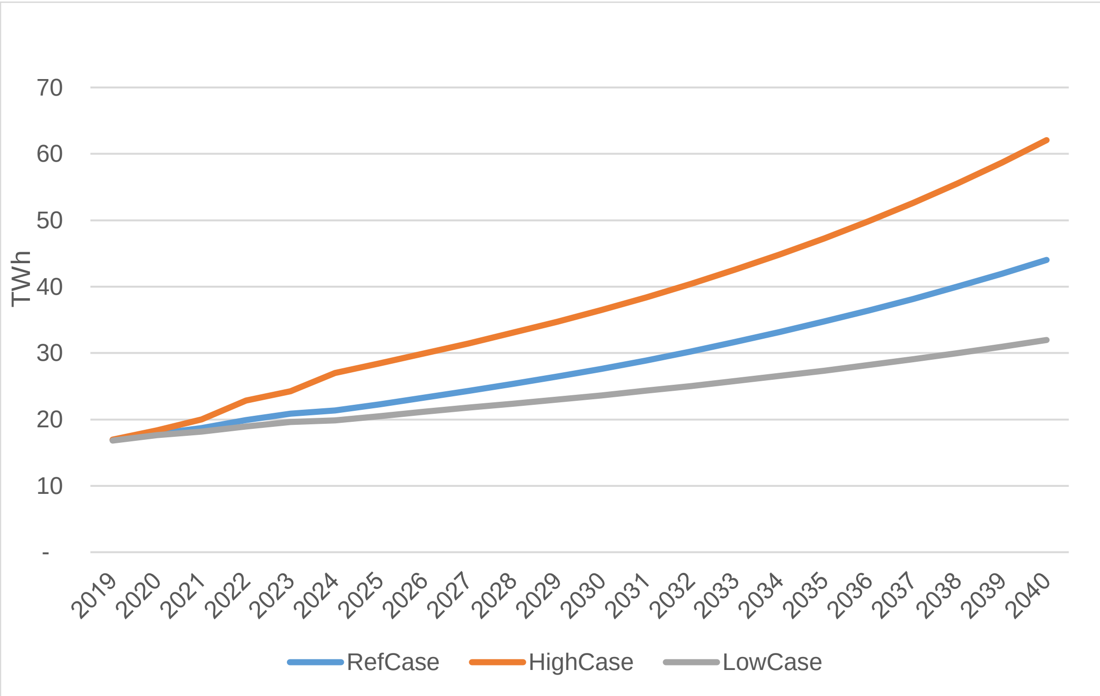
Figure 22 shows the ensuing total energy demand projections. The energy demand projections were converted to peak forecasts using load factors, as in the Reference Case, depicted in Figure 23.

Figure 21: Comparison of GDP Growth Rates used for Selected Forecasts



Source: IRRP Project.

Figure 22: High and Low Energy Demand Forecasts

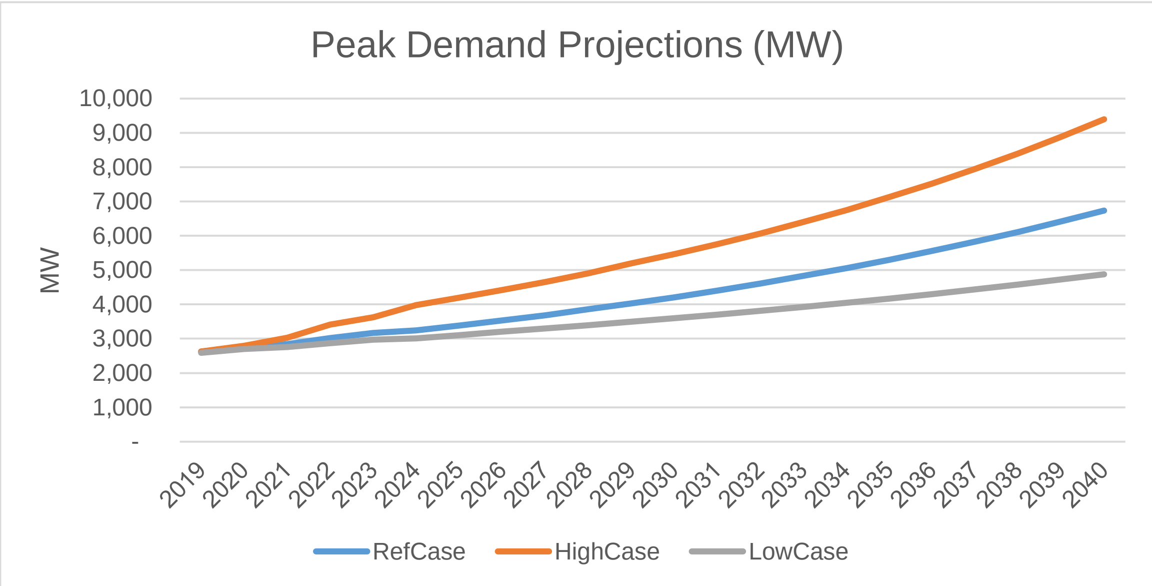


These cases had different forecasts for the ECG and NEDCo demand areas, based on different expectations of future GDP growth, as GDP was the only explanatory variable. Compared to a long-term average of 6% real GDP growth rate in the Reference Case, the

High Demand Case had GDP growth of 8%, and in the low demand case, long-term GDP growth was only 3%. The High Case GDP growth rates are consistent with that of the projections made by the NDPC for the Ghana Infrastructure Plan, as part of NDPC's Long-Term National Development Plan.

Demand scenarios for EPC were provided by the company. The demand projections for VALCO, the bulk customers, and exports, a series of discussions were held with GRIDCo and the Ministry of Energy to determine potential high and low demand sensitivities for these sectors.

Figure 23: High and Low Total Peak Demand Forecasts



5.3.1. 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 24 illustrates the increased and reduced estimates. See Figure 16 for reference demand.

5.3.1. 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 IRRP team to determine LDCs at a zonal level. Therefore, all the four zones used a common LDC based on the chronological hourly load data from 2018 for all of Ghana, which was provided by GRIDCo.[39] Similarly, the 2016 hourly

[39] The actual 2016 hourly load data were "corrected" to remove large dips in the load, during periods of generation outages or transmission problems.

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 24: Increased and Reduced Energy and Peak Demand Exports

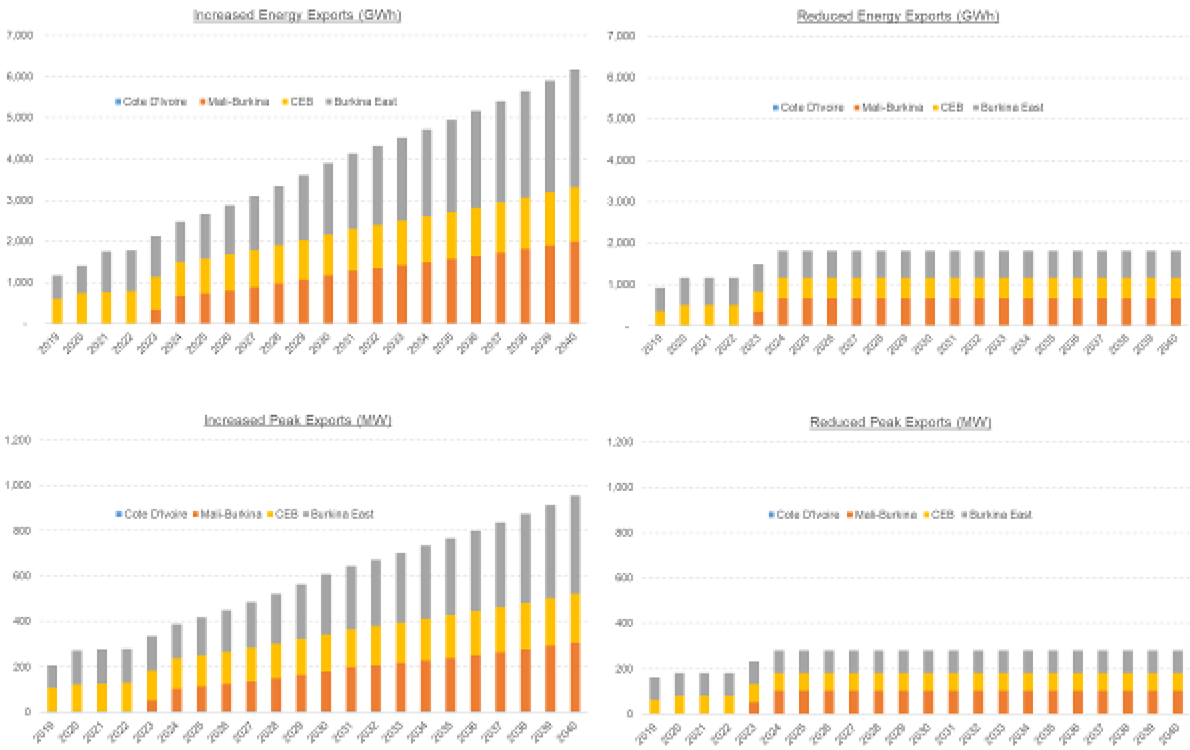
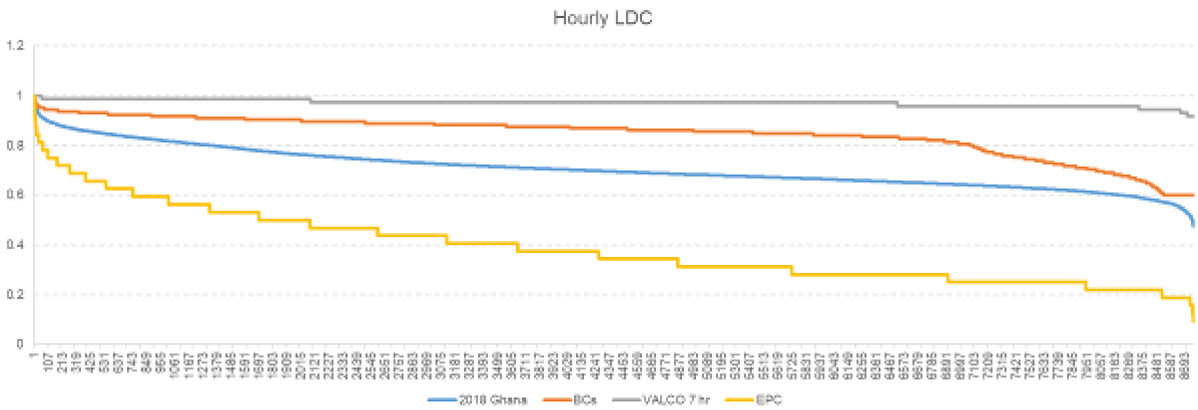


Figure 25 shows final LDCs derived from the hourly data. For the *GH-IPM 2019v1*, the reference load shape was not varied over time. In other words, although in the long term the hourly load shapes could vary (e.g., due to greater industrialisation or higher penetration of air conditioners), this potential change was not considered in the current version.

Figure 25: Load Duration Curves scaled to a 1000 MW Peak



5.3.2. Cost of Unserved Energy

The cost of unserved energy in the *GH-IPM 2019v1 model* is 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 17. These values were used as inputs on the cost of unserved energy for various IPM model regions.

Table 17: Cost of Unserved Energy used in GH-IPM 2019v1

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

It should be noted that the 2013 ECG study relies on very old information from surveys conducted in the United States on the value of lost load. Therefore, the modelling would benefit from updated Ghana-specific surveys to determine the cost of unserved energy.

5.3.3. Limitations of IPSMP Demand Forecasting

The IPSMP demand forecasting is based on a regression of historical electricity consumption with GDP. However, 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 due to self-generation, power theft, non-metering, meter malfunctions, etc. 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 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.

Subject to data integrity issues, data used for the load forecasts included the following:

- Gross electricity generated, as metered at the generating plants
- Net electricity supplied to the grid,[40] as metered by GRIDCo at power plant sites
- Electricity purchases, as computed by ECG/NEDCo/EPC/GRIDCo based on metered data at BSPs
- Electricity sales, as computed by ECG/NEDCo/EPC/GRIDCo based on metered data at customer sites
- Distribution losses: (purchases-sales)/purchases
- Transmission losses: (net supply from power plants-purchases)/net supply
- Imports and exports, as reported by GRIDCo and WAPP

The need to determine the “true demand” for Ghana, which is inclusive of suppressed load, is therefore, very critical for any planning initiative. Furthermore, the importance of price

[40] Excludes internal consumption or own plant use.

sensitivity of sales and data collection problems, impact of energy efficiency among others, should be considered in future analysis.

5.4. GENERATING RESOURCES

As discussed in the previous chapter, there are three general types of generating units modelled in *GH-IPM 2019v1:*

- "Existing": Units that are operational in Ghana electric industry, as of June 2017.
- "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. For *GH-IPM 2019v1,* firmly planned units were defined as units that were physically under construction as at June 2019.
- "Potential": New generating 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 19. 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.

The Ameri power plant is expected to be transferred to VRA in 2021 as per its build-own-transfer (BOT) contractual arrangement.

Table 20 shows the firmly planned, under-construction power plants in Ghana, as of June 2019.[41] Some of these power plants are expected to come in the last quarter of 2019 and early 2020, although their specific commissioning dates may vary. The Amandi power plant for

[41] Since August 2017–July 2018, there have been significant delays (by more than 6 months) for some of the firmly planned power plants. However, there changes will be captured in the upcoming update of the IPSMP in 2019.

example, due to delays on construction delays, did not come online as estimated in the model and this will have to be updated in the next version of the IPM. Assumptions for Early Power remained the same as the 2018 version, namely that Early Power comes online in three phases – first 152 MW coming online in 2020, second phase of 48 MW coming online in 2021 and the third phase coming online in 2024.

Table 21 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 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 retirements 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. The table below is a list of the specific power plants with their respective online and firm retirement dates in the model:

Table 18: Contractual Firm Power Plant Retirement Dates in *GH-IPM 2019v1*

Plant Name	Online Date	Firm Retirement Date
CENIT	03/10/2013	10/03/2033
BXC Solar	15/01/2016	15/07/2036
KarpowerShip	01/01/2018	01/08/2037
AKSA	8/1/2017; 1/1/2019	01/11/2023

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 IRRP team, based on discussions with various Ghana stakeholders, including the VRA, BPA, PURC, and the Energy Commission. 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 this table 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 19: Existing Power Plants in Ghana, as of June 2019

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	340	305	300
TICO (T2)	Jun-2000	Takoradi, Western	3	Volta River Authority	LCO/Gas Combined Cycle	330	320	320
TT1PP	Jun-2009	Tema, Greater Accra	1	Volta River Authority	LCO/Gas Combustion	110	100	100
TT2PP	Jun-2010	Tema, Greater Accra	5	Volta River Authority	Gas Combustion Turbine	49.5	45	45
SAPP 1	Sep-2011	Tema, Greater Accra	6	Volta River Authority	Gas Combustion Turbine	204	180	180
VRA Solar	Jan-2013	Navrongo, Northern	1	Volta River Authority	Solar Photovoltaic	2.5	1.8	0
Bui	Jun-2013	Bui, Brong Ahafo	3	Bui Power Authority	Hydro: Hydro (Utility)	399	330	330
CENIT	Oct-2013	Tema, Greater Accra	1	Cenit Energy Limited	LCO Combustion	110	100	100

Plant Name	Online Date	Region	No. of Units	Operating Utility	Capacity Sub-Type	Installed Capacity (MW)	Net Dependable Capacity (MW)	Reserve Margin Contribution (MW)
KTPP	Oct-2015	Tema, Greater Accra	2	Volta River Authority	DFO/Gas Combustion	220	200	200
KarpowerShip	Sep-2019	Takoradi, Western	13	Karpower Ghana Ltd	HFO/Gas Combined Cycle	494	450	450
BXC Solar	Jan-2016	Winneba, Central	1	BXC Company	Solar Photovoltaic	20	18	0
Ameri	Feb-2016	Takoradi, Western	10	Ameri	Gas Combustion	250	230	230
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	15	AKSA Energy Ghana	HFO/Gas Combined Cycle	370.5	350	350
SAPP 2	Mar-2017	Tema, Greater Accra	4	Sunon Asogli Power Co.	LCO/Gas Combined Cycle	401	370	370
Cenpower	Jun-2019	Tema, Greater Accra	3	Cenpower Generation Company	LCO/Gas Combined Cycle	340	340	340
MeinEnergy Solar Plant	Sep-2018	Winneba, Central	1	Meinergy	Solar Photovoltaic	20	18	18
Total			83			4840	4398	4373

Source: Energy Commission, IRRP Project.

Table 20: Under-Construction Power Plants in Ghana

Plant Name	Online Date**	Region	No. of Units	Operating Utility	Capacity Sub-Type	Installed Capacity (MW)	Net Dependable Capacity (MW)	Reserve Margin Contribution (MW)
Amandi	Oct-2019	Takoradi, Western	3	AMANDI Energy	LCO/Gas Combined Cycle	194	190	190
Early Power‡	Jan-2024	Tema, Greater Accra	11	Early Power	LPG/Gas Combustion	405.5	377.5	377.5
Marinus Energy**	Jan-2021	Atuabo, Western	1	Marinus Energy Limited	Gas Combined Cycle	35	28.5	28.5
VRA Solar_kfW**	Sep-2020	Kaleo, Northern	3	Volta River Authority	Solar Photovoltaic	17	17	0
Total			28			901.5	843	826

Source: Energy Commission, PURC, IRRP Project.

‡ The first phase of the Early Power plant is expected to come online using LPG as fuel source in the first quarter of 2020, second phase comes online in 2021 and the third phase comes online in 2024. The first phase of Early Power plant has been experiencing delays in commissioning.

** 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 August 2017.

Table 21: 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	305	15%		7,783	18.7	5.0
TICO (T2)	SouthWestGH	320	15%		7,443	30.94	4.9
TT1PP	SouthEastGH	100	8%		11,315	14.3	6.5
TT2PP	SouthEastGH	45	8%		9,720	11.8;12.41	4.5
SAPP 1	SouthEastGH	180	15%		9,330	11.8	4.5
VRA Solar	NorthGH	1.8	0%		-	255.67	0
Bui	NorthGH	330	5%		-	27.74	1.63
CENIT	SouthEastGH	100	15%	Mar-2033	11,000	11.83	4.5
KTPP	SouthEastGH	200	8%		10,900	12.3	3.5
BXC Solar*	SouthWestGH	18	5%	Jul-2036	-	214.99	0
Ameri (as IPP)	SouthWestGH	230	8%	Feb-2021	11381	80.08	5.0
Safisana	SouthEastGH	0.1	15%		13,500	35.0	4.2
AKSA	SouthEastGH	350	10%	Nov-2023	8,500	15.69	2.55
SAPP 2	SouthEastGH	370	10%		7,800	15.69	10.98
Cenpower	SouthEastGH	340	7%		7,830	15.08	2.36
Karpowership	SouthWestGH	450	7%	Aug-2037	8,514	79.0	8.3
Amandi	SouthWestGH	190	10%		8,200	29.16	4.05

Plant Name	IPM Ghana Zone	Net Dependable Capacity (MW)	EFOR	Firm Retirement	Heat Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Early Power	SouthEastGH	377.5	7%		7,500	19.78	3.23
Ameri (with VRA)	SouthWestGH	230	8%		11381	14.54	4.17
Mein Energy*	SouthWestGH	18	5%	Sep-2038	-	214.99	0
Marinus	SouthWestGH	28.5	15%		9221	55.88	2.9
VRA Solar_kfW*	NorthGh	17	5%		-	255.67	0

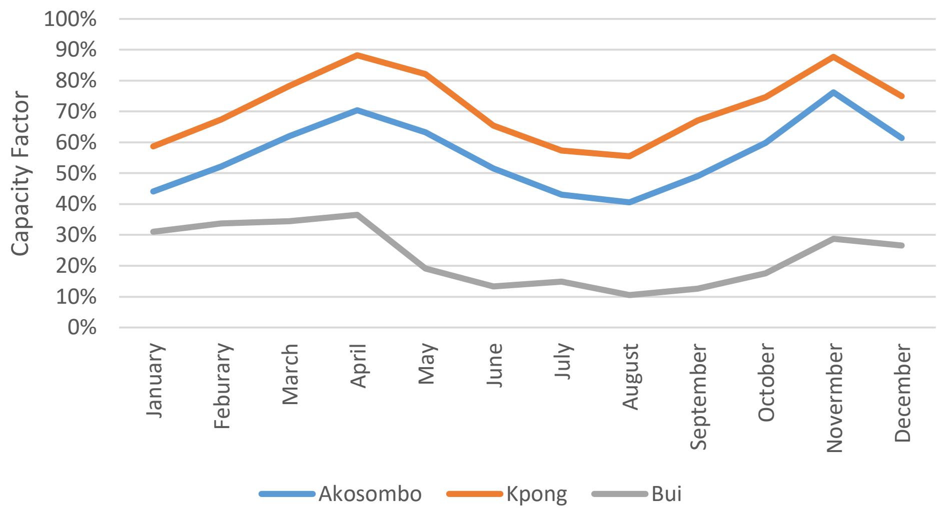
Source: Energy Commission, PURC, VRA, IRRP Project.

*These numbers are based on FiT and expected energy output

Table 22: Annual Capacity Factor Constraints for Selected Power Plants

Maximum Capacity Factor			
	Akosombo	Kpong	Bui
2019	50.9%	64.3%	23.2%
2020	50.9%	64.3%	23.2%
2021	56.3%	71.0%	23.2%
↓	↓	↓	↓
2040	56.2%	71.0%	23.2%

Figure 26: 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 26 and Table 22.

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 short-term future constraint (2018–2020) for the Akosombo and Kpong power plants is the need to build up the amount of water in the reservoir over the next 2–3 years, 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 are reduced from 2017 to 2020, but eventually reaching 56% for Akosombo and 71% for Kpong by 2021. From 2021 to 2040, the capacity factors are fixed at the long-term average. See Table 22.

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 2021 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 2021 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 23.

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 23, 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 23 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 23: Cost and Performance of Potential Power Plant Technologies for Ghana

Technology Type	Years of Const.	Overnight Costs w/o IDC[1] 2016$/kW	Capital Cost w/ IDC[2] 2016$/kW	Fixed O&M[3] 2016$/kW-yr	Variable O&M[3] 2016$/MWh	Heat Rate[3] 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 2016, IEA 2015, 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 2018 and 2020 was maintained as the High Case for the 2018–2019 and 2020–2037 periods, respectively. In all cases, the reduction factor used in the reference prices from 2018 to 2015 was applied for the various run years. Table 24 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%.[42]

Table 24: 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 2019v1,* unit specific operational and physical constraints are generally represented through availability and

[42] 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 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).

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 takes into account 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 2019v1* used IPM's effective forced outage rate (EFOR) function in specifying availability of the units. Table 21 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 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 the 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 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 on the impact of the loss of two critical generating units or plant 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 hydro plant. The cumulative capacity of 450 MW (Karpower) and 170MW (a unit of dependable capacity of Akosombo) was used to determine the planning reserve margin. This translates to about 22% of the 2019 projected peak of 2,829MW. As the load grows and the system expands with more units coming online, this value in percentage terms will reduce to about 20% and be maintained at 18% throughout the planning horizon. The specific reserve margins used in the *GH-IPM 2018.v1* are shown in Table 25.

Unlike what has been usually done by the various planning agencies so far (e.g., GRIDCo, ECG, EC), reserve margin assumptions in Table 25 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 2021) on its own, through firm transmission or new plants in the NorthGH Zone. Similarly, for each of the four Ghana zones. Therefore, reserve margin requirement in the *GH-IPM 2019v1* model is stronger than if it was enforced for all of Ghana, without considering transmission constraints.

Table 25: Reserve Margin Assumptions for each of the four GH Zones

Year	Annual RM
2018	25%
2019	22%
2020	21%
2021	20%
2022	19%
2023	18%
2024	18%
2025	18%
↓	↓
2040	18%

The contribution of the various power plants to the reserve margin is shown in Table 19 and Table 20, 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 2019v1* 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 2019v1*, 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 are 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 2019v1* are based on data collated from VRA, PURC, and ECG. Heat Rates for the existing and firmly planned power plants can be found in Table 21 and Table 23, respectively.

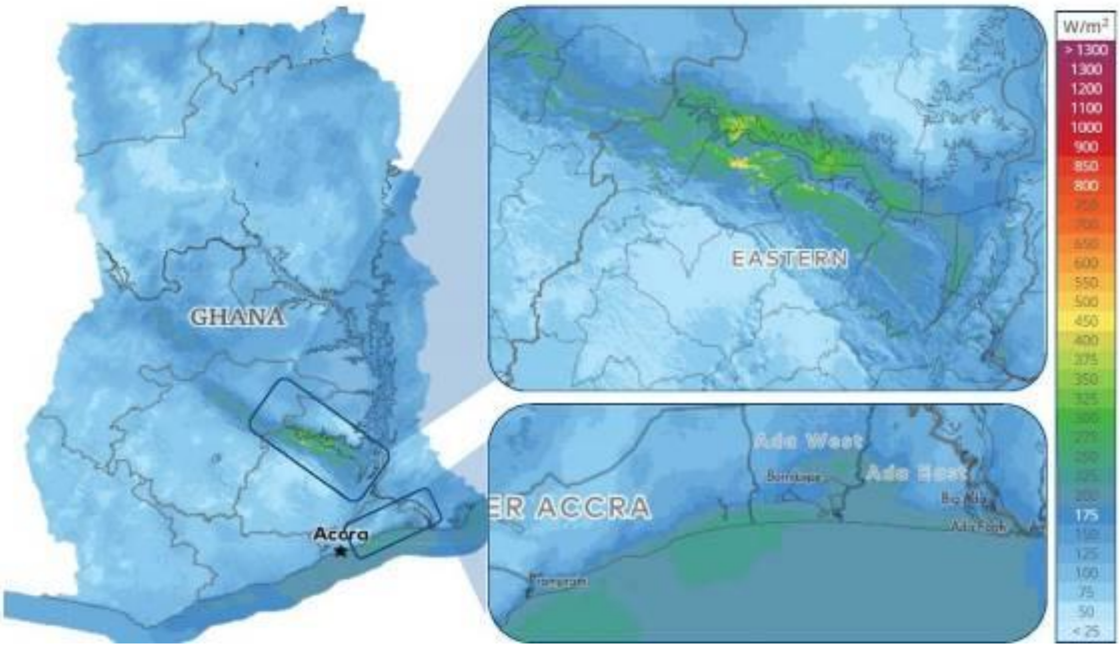
5.6. Renewable Energy Resources

5.6.1. Wind Generation

Wind Resource Potential: This version of the Ghana Model, *GH-IPM 2019v1*, 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 27) 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 2019v1 to* reflect the resource availability and the potential operational constraints that is inherent with variable renewable energy resources. As shown in Table 26, the maximum wind capacity limit used in the *GH-IPM 2019v1* is 700MW, although there is potential for more[43] it will require more detailed study to identify specific capacity limits per model region to inform the redefinition of limits in the model.

Figure 27: Wind Resource Map – Ghana



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

Table 26: Reference Wind Capacity Limit in the GH-IPM 2019v1

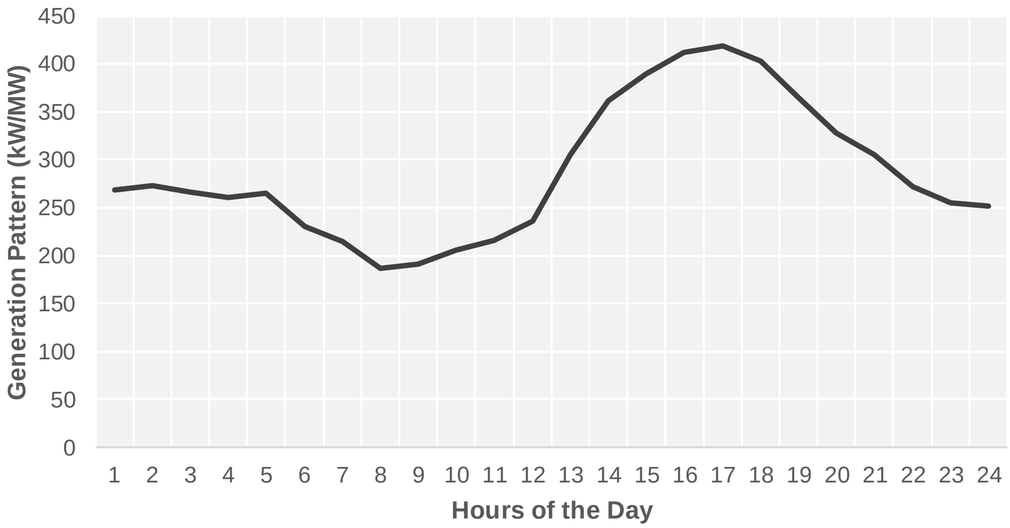
	IPM Model Zone	Maximum Capacity (MW)
Reference Case	SouthEastGH	700

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

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 28. 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 the intermittent nature of wind and the hours it is available relative to the peak demand hours, it does not fully contribute to the reserve margin. In the *Ghana-IPM 2018v1*, 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 28: Typical Wind Generation Profile used in the GH-IPM2019 v1.[44]



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.

[44] 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.

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 27.

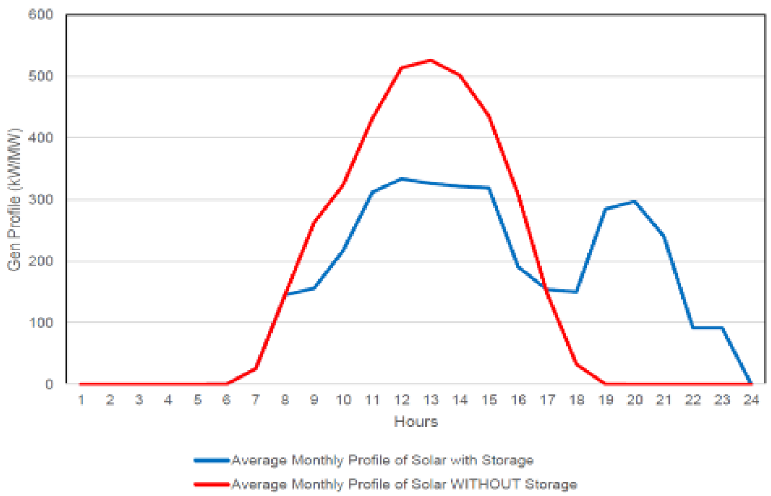
These limits are, however, nearly doubled in the high resource case for some strategies (e.g., the Indigenous Resources and the Enhanced G-NDC, see Chapter 7). A detailed study of specific limits for the various zones is needed to further fine-tune these constraints in the model. Below is a summary table of the capacity limits for Solar PV and Solar PV with Storage in the *GH-IPM 2019v1*.

Table 27: Reference Solar Photovoltaic Capacity Limit in the GH-IPM 2019v1

	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

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 it 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 29 shows a typical profile for both solar PV and solar PV with storage.

Figure 29: 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 2019v1 version are biomass (combustion and gasification) and biogas. These technologies were made available in all four regions given the ubiquitous nature of these resource 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. The Table 28 and Table 29 show the biomass capacity and availability constraint included in the model.

Table 28: Reference Biomass Capacity Limits in the GH-IPM 2019v1

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

5.6.1. 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 2019 version of the Ghana IPM does not include such RE targets; instead only the economics dictates the building of new renewable technologies.

5.6.2. Renewables-based Mini-Grids

Renew able energy-based minigrids are now becoming an important option for increasing electricity access in remote and lakeside communities. As such, the potential for minigrid development in Ghana was explored in a workshop in 2017. The proceedings of the workshop are provided in Volume 3.

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.

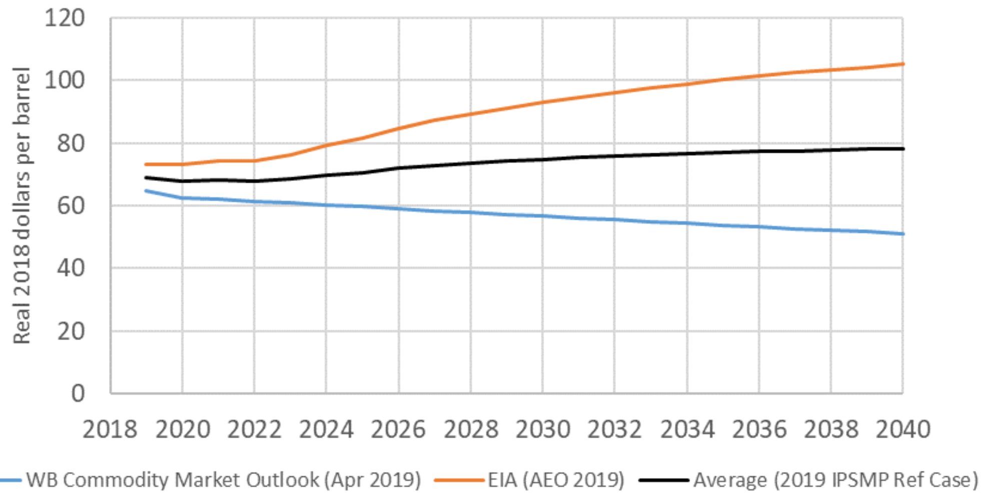
Table 29: Biomass Availability Constraint in the *GH-IPM 2019v1*

Year	Volume (MMBtu)
2019	10,129,169
2020	10,184,400
2021	10,240,483
2022	10,297,432
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 is shown in Figure 30, 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 30). 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 30: Crude Oil Price Forecasts ($/bbl) in 2018$

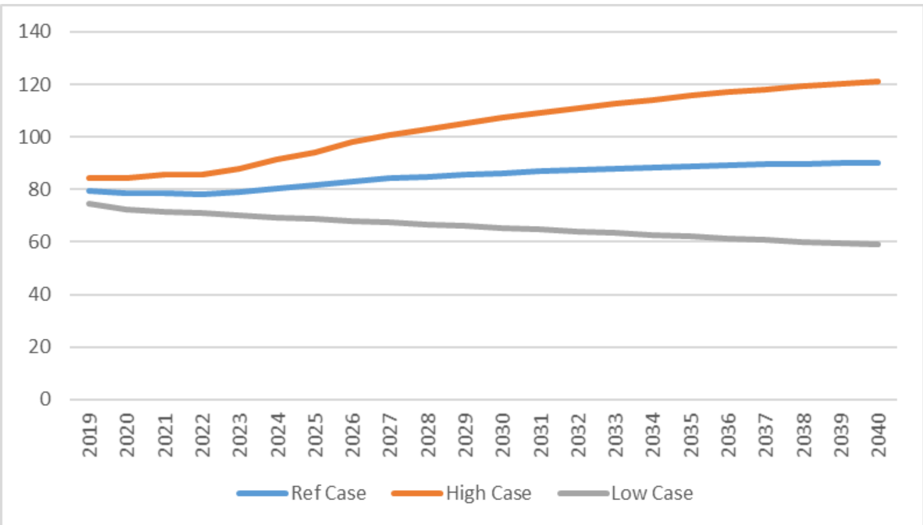


Liquid fuel prices (HFO, LPG, and DFO) and LNG prices are modelled as a percentage of the oil price.

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 31.

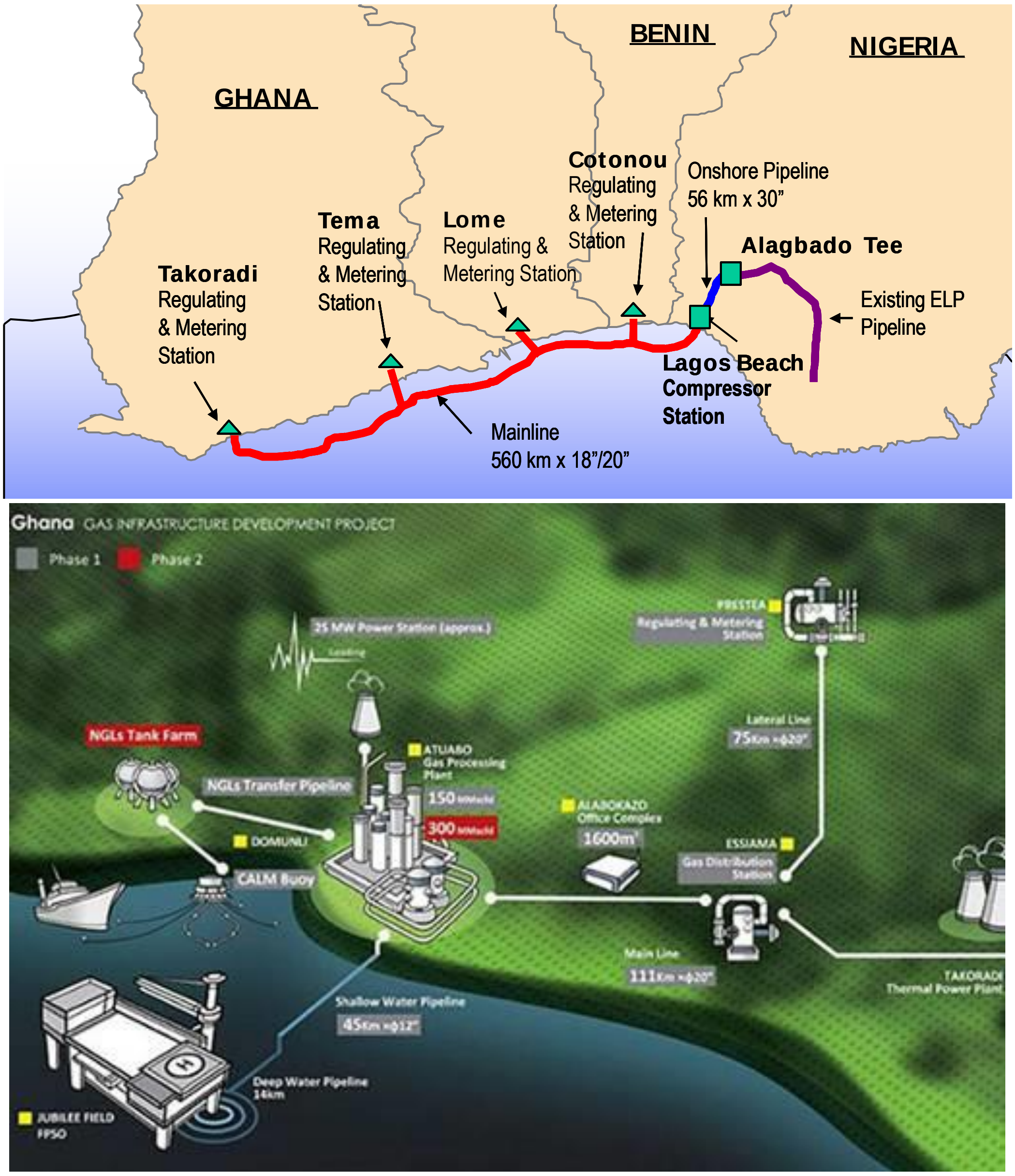
Figure 31: Crude Oil Price Sensitivities



5.7.2. Natural Gas

As of December 2017, there are 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 32: Existing Natural Gas Pipeline Infrastructure for Gas Supply in Ghana

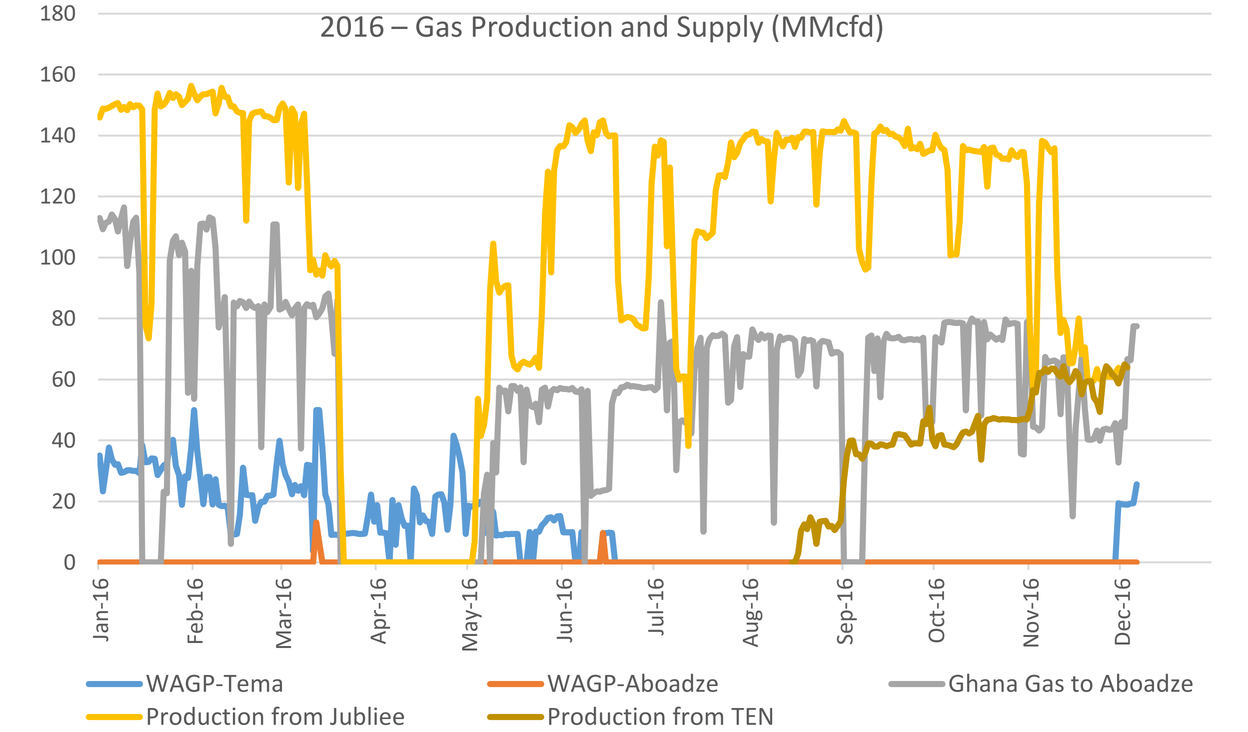


Source: GNPC, WAGP.

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 is processed onshore at Atuabo, and then delivered to power plants in the Aboadze power enclave. Figure 32 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 30). 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.

Figure 33: Production and Supply of Natural Gas in Ghana in 2016



Source: GRIDCo.

However, a number of issues including supply interruption in 2011 to 2012 and gas supply issues in 2013–15, 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 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 and storage unit (FPSO) which resulted in interrupted supplies to TAPCO, TICO, and Ameri. Figure 33 shows the gas production and supply in 2016 and highlights the number and extent of interruptions to gas supply in Ghana. Figure 33 also shows the production of gas from the Tweneboa, Enyenra, Ntomme (TEN) fields starting in late 2016; however, TEN gas was only connected to the raw gas pipeline to the Atuabo processing plant in March 2018. Unlike 2016, gas supply to Ghana power plants was more stable in 2017, particularly from WAGP, which allowed for more gas-fired generation in Tema. In general, gas suppliers in Ghana (WAGP and Ghana Gas) were not entirely in control of supply because WAGP was limited by both availability of gas from Niger Delta and infrastructure interruptions, and Ghana Gas has been—to this point—dependent on associated gas production from oil production and challenges with the FPSO.

Table 30: Annual Gas Supply Volumes (MMBtu)

Year	WAGP (Nigeria)	Indigenous Production
2009	198,000	
2010	15,617,000	
2011	30,525,000	
2012	15,447,000	
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

Source: Energy Commission, 2018.

As a result, power plants had to switch to LCO when gas supply was interrupted, which caused problems with "coking" inside the burners and nozzles, resulting in unplanned plant outages. At the same time, when gas was available, outages in power plants (because of needed maintenance due to coking issues and financial challenges) led to a situation where sometimes the plants were unable to use the gas when it was available.

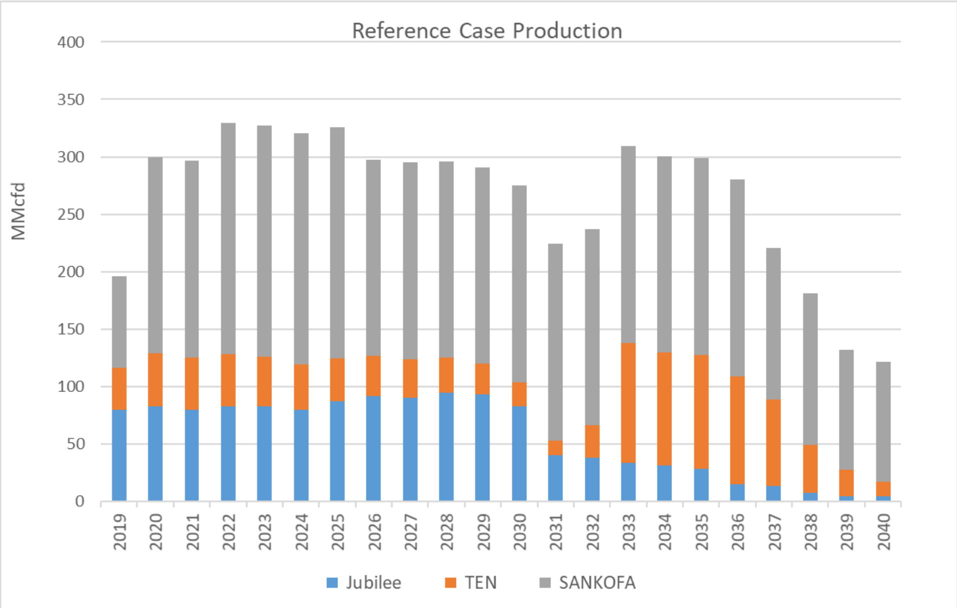
Natural gas has been playing, and is expected to play, an important role in Ghana's power sector, but it had gotten off to a poor start in terms of reliability. Ensuring reliable gas supply has become a key concern for power planners, and therefore there is significant interest in developing LNG imports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

According to GNPC's "base-case" projections of indigenous gas production, Jubilee and TEN is expected to decline over time, without additional development and production in those fields. Figure 34 shows the expectations of indigenous gas supply, as per discussions with GNPC. These projections demonstrate that without any other new field development, gas production is expected to decline significantly starting in 2037. However, additional new field development and production will extend further the production of domestic gas.

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, given that Jubilee and TEN fields are associated gas fields, 100% of the production from these fields must be consumed by Ghana power plants. For planning purposes, large-scale gas use at this stage is limited only to the power sector. If other uses for gas do become a reality then the obligation for Ghana's power sector to consume the Sankofa gas decreases and would have to be revised in the model to reflect the changes.

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 Sankofa 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 120 mmcfd starting from 2020 onwards. 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 34: Average Daily Production Profile for Indigenous Gas – Reference Case



Source: GNPC.

For modelling purposes, Nigerian gas through the WAGP was capped at about 120 million cubic feet per day (MMcfd) of daily average gas supply to power plants in Tema, starting in 2019.

From discussions with GNPC, additional new field development and production is expectant in the late 2020s hence this 2019 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 as the aggregator is considering several LNG regasification proposals. For modelling purposes, LNG supply is only being allowed for power plants in Tema. **However, it is critical recognize that LNG is simply a proxy for the need for additional gas supply beyond what has been assumed.** In other words, additional gas supply from domestic resources can replace the LNG supply.

The Southeastern LNG (supporting Tema plants) is expected to have a maximum daily average capacity of about 196 MMcfd of LNG starting from 2022. LNG availability does not, however, imply that the LNG must be consumed. Instead, the model can use LNG as an option up to these maximum limits, if it is cost effective.

Currently there is no gas pipeline infrastructure available for transporting gas to the Middlebelt area, as the pipeline only extends to Prestea. However, the model is provided with an option for any power plants that could be built in the Middle Belt areas to have access to indigenous gas from Atuabo. In essence, the model assumes that natural gas could be transported from the Atuabo gas processing facility all the way to Kumasi/Middle Belt area, through a new pipeline from Prestea, 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.

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).

Figure 35 shows the modelled gas prices in the IPM in real 2016$. Each of the different supply points (Jubilee, TEN, and Sankofa) have different prices and midstream (processing and pipeline) costs. The commodity costs for these supply points were determined in discussions with GNPC and other stakeholders. The delivered cost of domestic gas to power plants in Tema and Takoradi are based on a volume-weighted price of gas from Jubilee, TEN, and Sanfoka. The price of the non-foundation Jubilee gas is set to zero from 2019 to 2022 with Post-Foundation Jubilee gas setting the price of $2.35/MMBtu (2017$) from 2023 onwards and the midstream prices for Jubilee gas assumed to be $3.35/MMBtu.[45] TEN gas prices are expected to be much lower than Jubilee, with associated gas assumed to have a cost of $0.52/MMBtu and non-associated gas at $3.12/MMBtu. The midstream costs for TEN and Sankofa are assumed to be $1.34/MMBtu and 0.85/MMBtu respectively. Hence, when the re-injected gas from TEN is produced, starting in early 2030s, the domestic gas price decreases.

Sankofa production is dependent on the headline price of gas, as well as on the prices of the government share of the Sankofa gas. It is assumed that the final commodity price of Sankofa is about $7.61/MMBtu.

Considering the production profiles of the various gas fields (see Figure 34), the weighted average costs of the domestic gas for power plants is determined, as shown in Figure 35. The cost of domestic gas to plants in the Tema enclave (SouthEast zone) has additional cost $2.1/MMBtu as the cost of the reverse flow of gas on the WAGP gas pipeline between Aboadze and Tema.

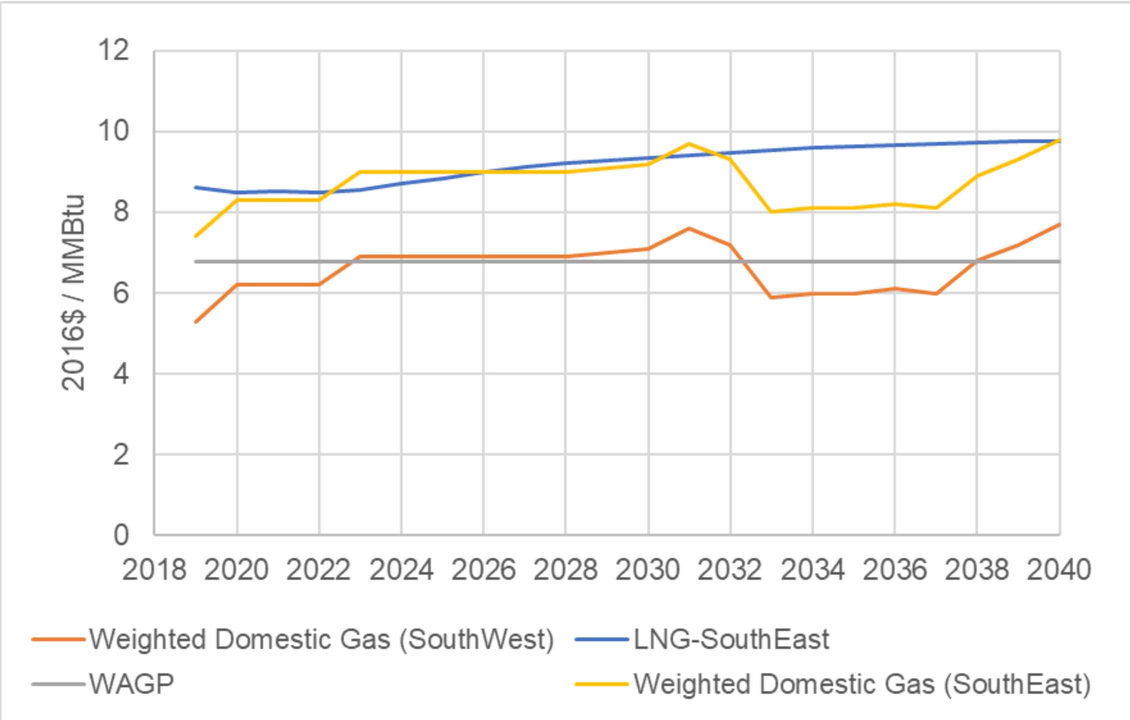
[45] Based on discussions with GNPC staff and other stakeholders.

The cost of WAGP is fixed at $6.79/MMBtu in 2016$ throughout the planning period, and price of LNG is based on the Reference Case oil prices, as discussed in the subsection below. Reference Case LNG prices are expected to rise steadily from 2019 onwards, in line with oil prices.

A summary of the gas volumes and prices are shown in the table below:

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Jubilee Gas	MMCF.D	80	83	79	83	83	80	87	92	90	94	93	82	40	38	34	31	28	15	13	8	4	4
TEN Associated Gas	MMCF.D	28	28	28	28	28	28	28	28	28	26	23	18	10	26	103	97	99	94	75	41	23	13
TEN Non-Associated Gas	MMCF.D	9	18	18	18	15	12	9	7	6	5	4	3	2	2	2	1	1	1	0	0	0	0
Sankofa / Gye Nyame Gas	MMCF.D	120	171	171	201	201	201	201	171	171	171	171	171	171	171	171	171	171	171	132	132	105	105
Total	MMCF.D	**236**	**299**	**296**	**330**	**327**	**321**	**325**	**298**	**295**	**296**	**291**	**275**	**224**	**237**	**309**	**301**	**299**	**280**	**220**	**181**	**132**	**121**
Sankofa Take or Pay	90%		154	154	181	181	181	181	154	154	154	154	154	154	154	154	154	154	154	119	119	94	94
Weighted Average Cost	2019$/MMBtu	5.28	6.20	6.23	6.41	7.01	7.05	7.04	6.89	6.90	6.92	6.99	7.14	7.61	7.24	5.94	6.02	6.00	6.09	6.04	6.83	7.22	7.68

Figure 35: Delivered Price of Gas to Power Plants

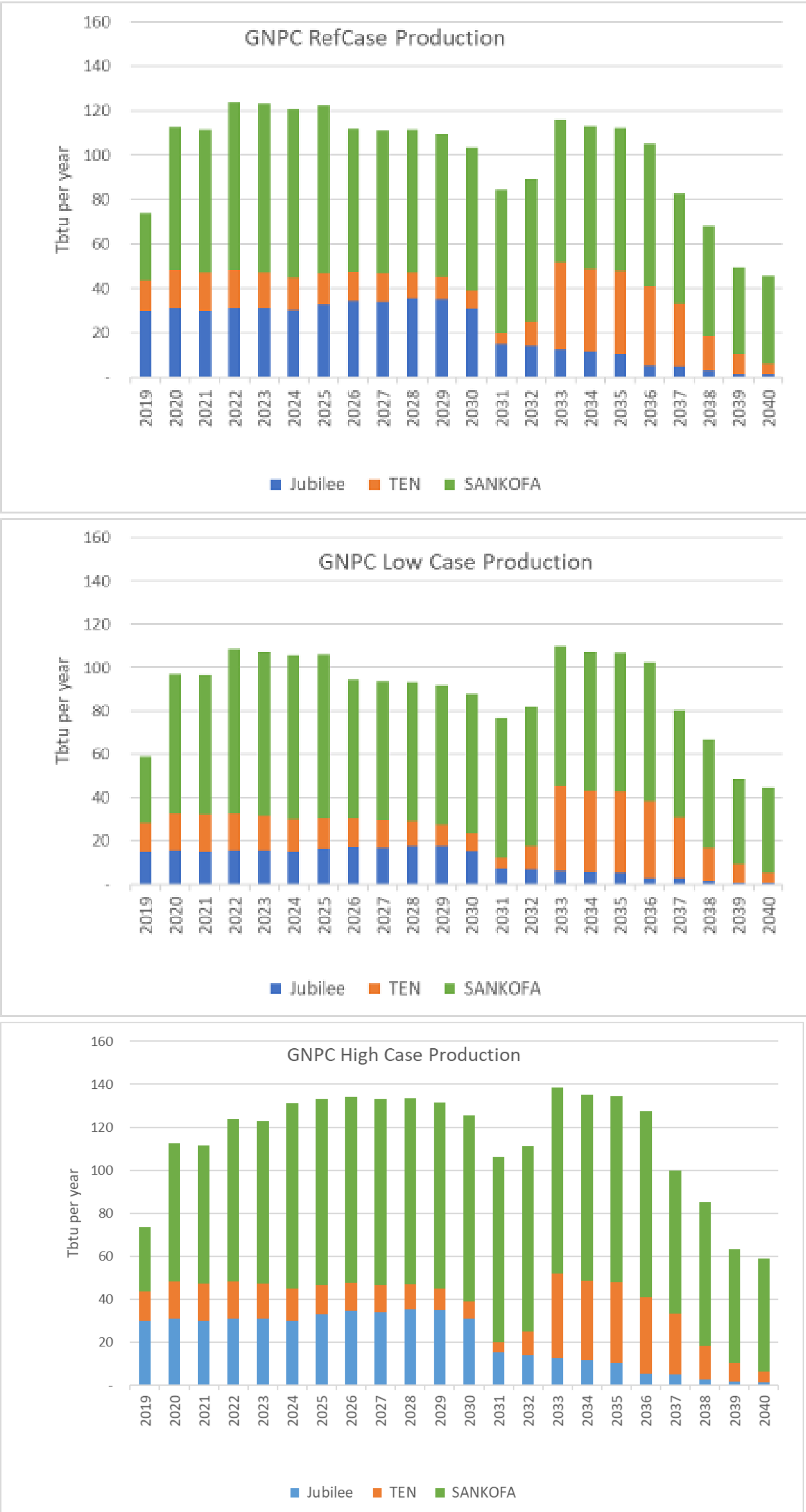


Source: GNPC, IRRP Project.

Summary of Changes to Gas Supply/Prices for 2019 IPMSP update is shown below:

- Price for the government share of Foundation-Jubilee to set to $0
- Post-Foundation Jubilee gas set to $2.35/MMBtu (in 2017$)
- Headline price of Sankofa gas reduced to $8/MMBtu (in 2019$) (incl. gov't share)
- Gas processing, transportation charges, and levies: $3.5/MMBtu for Jubilee, $1.4/MMBtu for TEN, and $0.9/MMBtu for Sankofa; all in 2019$.
- Added $2.1/MMBtu (in 2016) to reverse-flow gas on WAGP to move gas from the Aboadze enclave to the Tema enclave.
- Sankofa "paid-for gas" will be supplied to power plants from 2022 to 2024
- Lower N-Gas price on WAGP at about $6.5/MMBtu ($2019)
- Assumes LNG to be purchased on the spot market

Figure 36: Sensitivity of Domestic Gas Production.



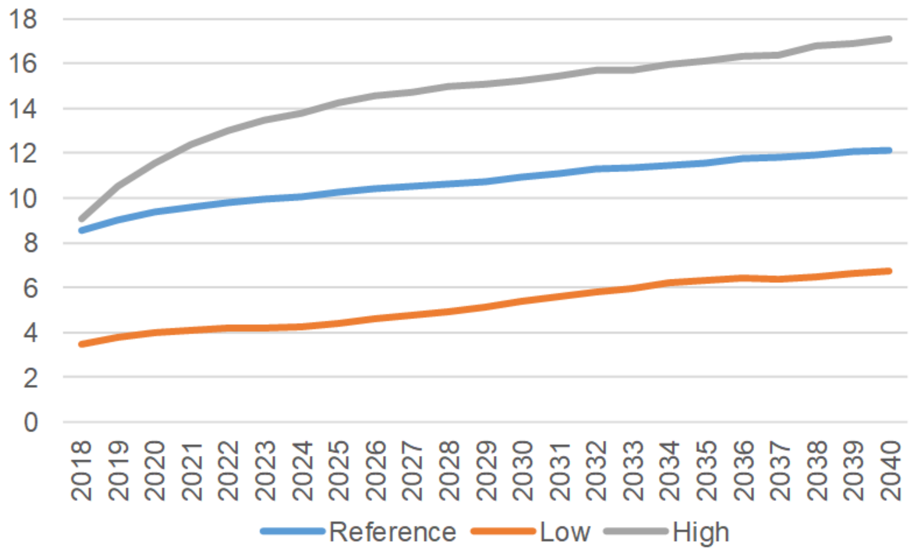
Source: GNPC, IRRP Project

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 36.

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 37.

Figure 37: LNG Commodity Prices in 2016$/MMBtu .



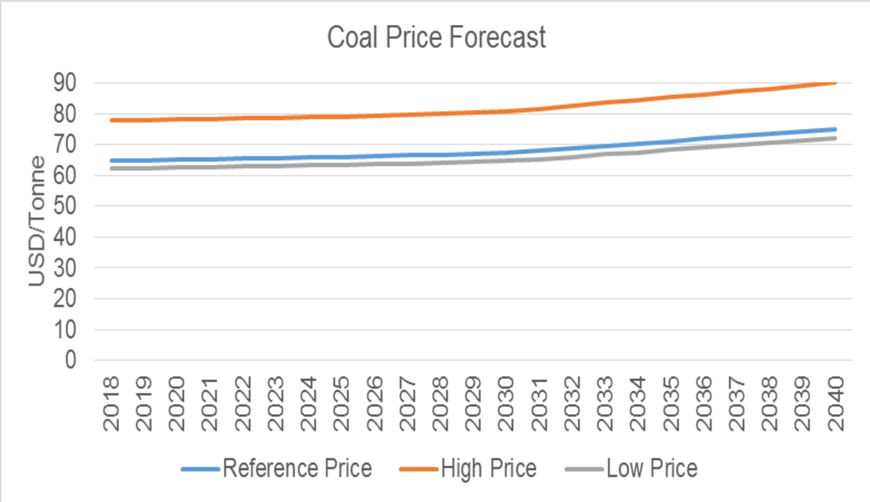
Source: IRRP Project.

5.7.5. Coal Prices and Transport

VRA has been considering the development of a coal power plant to be located in the Central Region of Ghana. As such, the use of coal has been considered as a potential option for power generation. To develop a coal power plant, coal import facilities will need to be constructed at a port, as will the coal storage, transport, and handling facilities. Therefore, the capital costs of constructing a new coal power plant need to include the capital investments needed for coal import and handling. These costs have been accounted for in the costs shown in Table 23.

It is expected that coal imports into Ghana would primarily come from South Africa, and as such, projections of South Africa coal prices used in the model are shown in Figure 38. Additional costs for insurance, freight, and coal transportation are included separately on top of the free-on-board (FOB) prices.

Figure 38: South African Coal FOB Price Forecast



Source: IRRP Project.

5.7.6. 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 2019.v1 model, a very small 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 39 shows the schematic diagram of the transmission links/corridors between the zones, and Table 31 shows the updated firm and non-firm TTCs between various zones, based on transmission flow analysis that was conducted on the Ghana's power system using the PSS/E model. The expected completion of various transmission lines in 2019, particularly the expansion from Aboadze to Prestea, Prestea to Kumasi, and the Kumasi to Bolgatanga would allow for the increased TTCs starting in 2019.

Figure 39: Schematic Diagram of the Transmission Paths

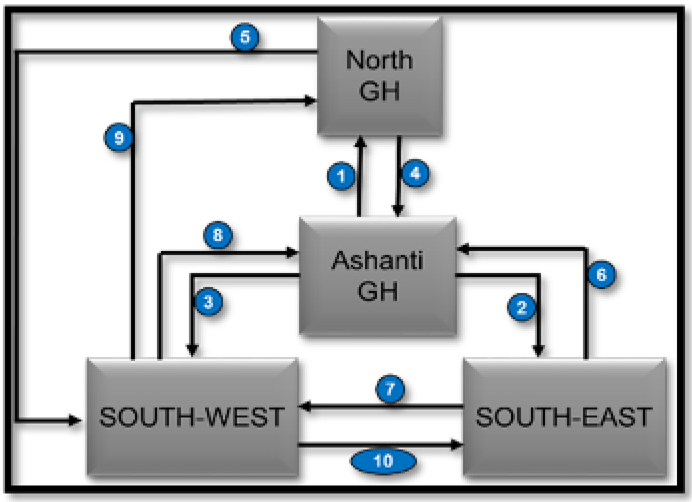


Table 31: Firm and Non-Firm TTCs between Ghana Zones

Link No.	From Ghana Zone	To Ghana Zone	2019–2040	
			Non-Firm TTC	Firm TTC
1	AshantiGH	NorthGH	1,091	914
2	AshantiGH	SouthEastGH	345	342
3	AshantiGH	SouthWestGH	215	211
4	NorthGH	AshantiGH	345	269
5	NorthGH	SouthWestGH	95	0
6	SouthEastGH	AshantiGH	380	236
7	SouthEastGH	SouthWestGH	320	320
8	SouthWestGH	AshantiGH	522	522
9	SouthWestGH	NorthGH	47	0
10	SouthWestGH	SouthEastGH	550	350

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.

6.1. Methodology Overview

First, a few specific terms need to be defined—strategy, sensitivity, and portfolio. A *strategy* 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 defines 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.

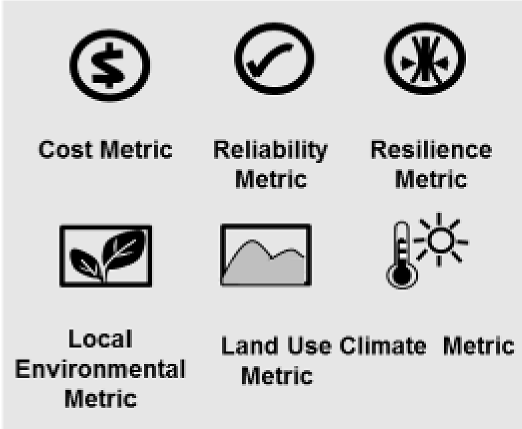
However, to identify the Least-Regrets Strategy, several different electricity supply policies/strategies were considered for the Ghana power sector. These strategies represented potential policy options for the power sector that the Government of Ghana could consider. The strategies had their own set of constraints (discussed below) and each were optimised to identify least-cost model solution using the Reference Case model assumptions in the *GH-IPM 2019v1*.

The IRRP team tested 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 were discussed 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 planners 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 than 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.

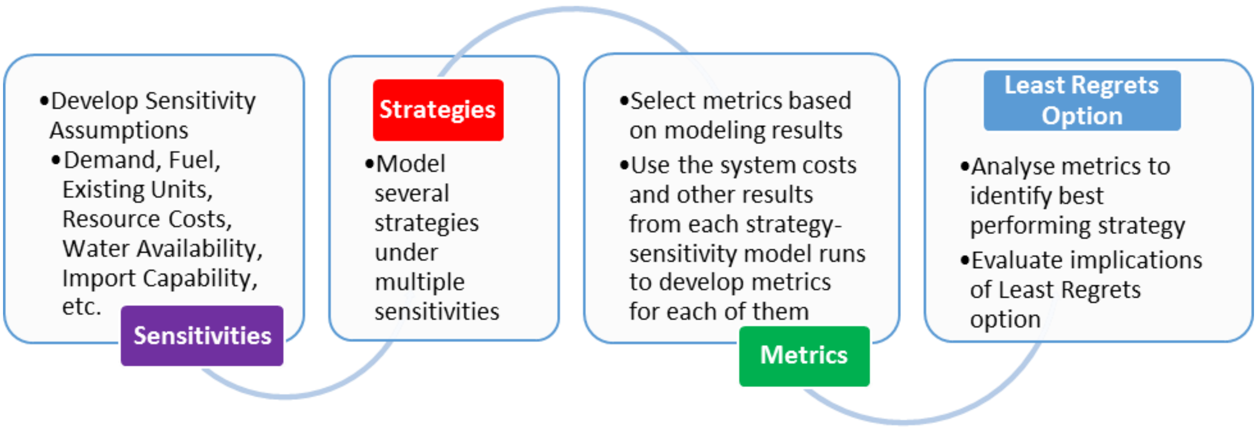


These metrics are then statistically analysed to determine a score for each strategy, and the strategies are then ranked based on their scores.

However, the cost metric was selected by the IRRP Technical and Steering committees as the highest-priority metric, hence strategies that were highly ranked in the cost metrics (low cost) were further evaluated to test their performance in the other metrics to assess their overall performance.

The most cost-effective portfolio that performs generally well under all the selected metrics is considered as Least-Regrets Strategy. Figure 40 summarises the basic methodology used in the identification of the Least-Regrets Portfolio.

Figure 40: Schematic for Identifying Least-Regrets Option for the IPSMP



6.1.1. Strategies

The set of different power sector policies (i.e., strategies) considered for the Ghana power sector are shown in Table 32. These strategies are possible policy directions the Government of Ghana could embark on, and were finalised in discussions with the IRRP Technical and Steering committees. The supply strategies were also informed by the current planning environment of Ghana's power sector, and are detailed in Chapter 4.

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 32: Strategies Evaluated for IPSMP

#	Strategy Name	Description
I	**Unconstrained**	• Reference Case assumptions on demand, technology costs, gas resource availability, RE bounds, TTCs, build 60MW small hydro • No other technology-specific constraints on build options
II	Diversify with **Coal**	• Reference Case assumptions on demand, technology costs, TTC, build 60MW small hydro • Diversify fuels by building a 700MW coal power plant in two phases: 350MW in 2027 and 350MW in 2030 in SouthWest-GH
III	Diversify with **Nuclear**	• Reference Case assumptions on demand, technology costs, gas resource availability, RE bounds, TTCs, build 60MW small hydro • Diversify fuels by building a 1000MW nuclear power plant in two phases: 500MW in 2030 and 500MW in 2035 in SouthWest-GH
IV	**Diversify Geographically**	• Reference Case assumptions on demand, technology costs, gas resource availability, TTCs, build 60MW small hydro • Build a 300 MW combined cycle plant in Ashanti-GH by 2027
V	**Renewable Energy Master Plan** (REMP)	• Reference Case assumptions on demand, technology costs, TTCs, build 60MW small hydro • Implementation of on-grid utility-scale RE capacities identified in the Renewable Energy Master Plan (REMP)
VI	**Enhanced G-NDC*** Reduced CO_2 growth	• Reference case assumption on demand, technology costs, gas resource availability, TTCs, build 60MW small hydro • 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).

6.1.2. 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 33. 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 10 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 10 years to an optimised build portfolio that takes the high or low demand growth into account. Table 33 describes the sensitivities.

Table 33: List of Sensitivities Modelled for IPSMP

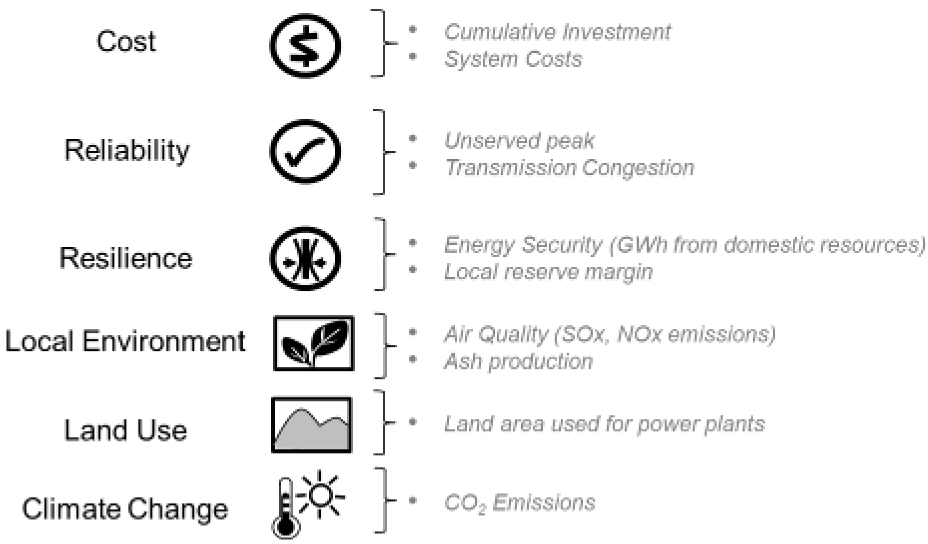
#	Sensitivity	Description
0	Reference Assumptions	• As described in the Modelling Assumptions chapter
1	High Demand Growth	• Demand growth for peak and energy demand exceeds the Reference Case, with an 8.5% long-term average GDP growth, which is consistent with SNEP AEG and NDPC projections
2	Low Demand Growth	• Demand growth for peak and energy demand is lower than the Reference Case, with a 3% 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 2020 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 will be different for the future updates of the IPSMP.

6.1.3. 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 41 shows a breakdown of the main categories of metrics into sub-metrics.

Figure 41: Metrics for Strategy-Sensitivity Combinations



A brief description of these metrics, and their relationships to the IPSMP vision and objectives (see Section 1.1) is presented in Table 34.

For each supply strategy-sensitivity combination, these metrics were calculated over the 10-year (2019–2028) and the 19-year (2019–2037) modelling periods. For each strategy, the average was then calculated over the entire range of sensitivities for each metric.

6.2. MODELLING RESULTS

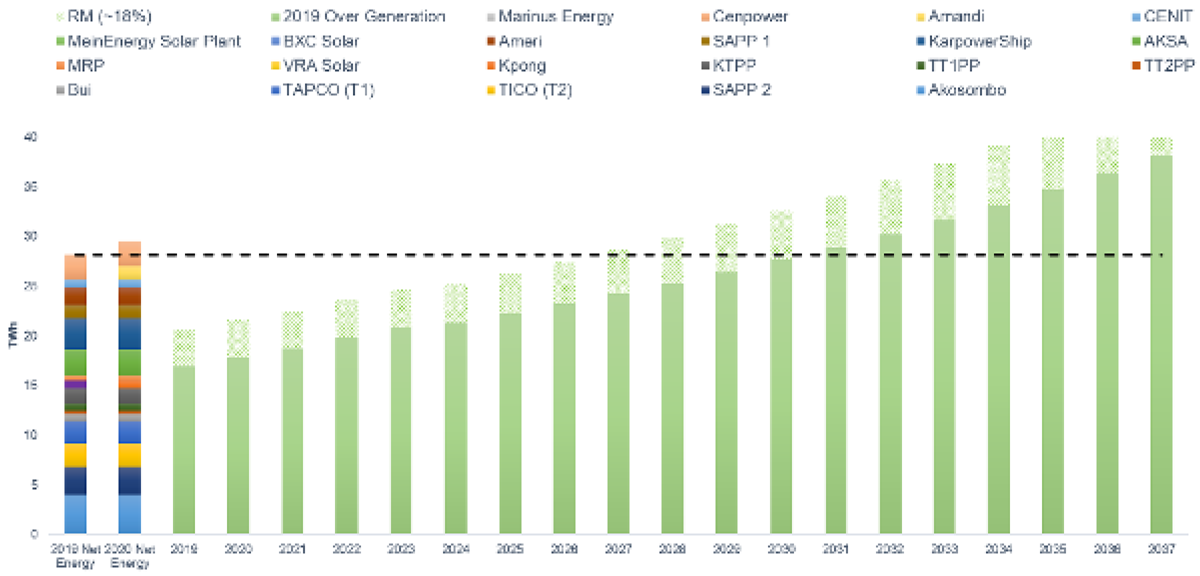
A simple analysis of the supply-demand balance indicates that existing generation and under-construction plants are sufficient to meet the growth in demand in the short-to-medium term. Figure 42 illustrates the simple supply-demand balance chart that shows 2019 and 2020 net generation from existing and under-construction plants along with the projected energy forecast up until 2037, a scenario when there are no challenges with fuel availability. Amandi, and Early Power Phase 1, which are plants under construction are earmarked to come online at the latest by the early part of 2020 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 34: 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 against developing and dispatching new, 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 42—especially if the generation is for lowering energy cost, as opposed to adding to the reserve margin.

Figure 42: Supply-Demand Balance in Ghana



The subsections below discuss the capacity expansion plans for the various strategies discussed in section 6.1.1. 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 35 and Table 36.

6.2.1. Unconstrained Strategy

Generation Capacity

The Unconstrained Strategy does not have any specific technology constraints, as indicated in Table 32 except with the building of, a small hydropower plant of about 60MW (Pwalugu) in the NorthGH zone which even through all the strategies considered. 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 power plants come online as early as 2023, primarily due 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 43 This strategy has the second highest percentage of renewables in the build portfolio at about 47% over the entire planning horizon.

Table 35: Summary of Capacity Additions (MW) for the 10-Year and Longer Term

	Strategy I		Strategy II		Strategy III		Strategy IV		Strategy V		Strategy VI	
	Unconstrained		Diversify with Coal		Diversify with Nuclear		Diversify Geographically		REMP		Enhanced G-NDC	
Capacity Type	**2019-2028**	**2029-2037**	**2019-2028**	**2029-2037**	**2019-2028**	**2029-2037**	**2019-2028**	**2029-2037**	**2019-2028**	**2029-2037**	**2019-2028**	**2029-2037**
Gas Combined Cycle	-	-	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combined Cycle	465	1,595	205	1,185	460	610	450	1,615	420	1,585	740	645
Gas Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-
Oil Reciprocating	-	-	-	-	-	-	-	-	-	-	-	-
Biomass Combustion	-	-	-	-	-	-	-	-	70	-	-	-
Oil Combustion	-	-	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combustion	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	60	-	60	-	60	-	60	-	80	-	60	-
Solar PV	410	680	150	530	300	495	490	810	355	175	820	1,000
Solar PV + storage	-	140	-	120	-	140	-	120	-	140	420	440
Coal Steam Turbine	-	-	350	350	-	-	-	-	-	-	-	-
Wind	275	250	125	250	200	250	275	250	325	-	350	250
Nuclear	-	-	-	-	-	1,000	-	-	-	-	-	440
Biogas	-	-	-	-	-	-	-	-	-	-	-	-
Conventional Thermal	465	1,595	555	1,535	460	1,610	450	1,615	420	1,585	740	1,085
Renewable Energy	745	1,070	335	900	560	885	825	1,180	830	315	1,650	1,690
% RE	62%	40%	38%	37%	55%	35%	65%	42%	66%	17%	69%	61%
TOTAL	**1,210**	**2,665**	**890**	**2,435**	**1,020**	**2,495**	**1,275**	**2,795**	**1,250**	**1,900**	**2,390**	**2,775**

Table 36: Total Generation (GWh) at the End of the 10-Year and Longer Term

	Current	Strategy I		Strategy II		Strategy III		Strategy IV		Strategy V		Strategy VI	
		Unconstrained		Diversify with Coal		Diversify with Nuclear		Diversify Geographically		REMP		Enhanced G-NDC	
Capacity Type	**2019**	**2028**	**2035***	**2028**	**2035***	**2028**	**2035***	**2028**	**2035***	**2028**	**2035***	**2028**	**2035***
Gas Combined Cycle	570	-	-	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combined Cycle	9,936	19,192	27,916	17,134	23,623	19,470	20,146	19,082	27,677	18,901	29,076	18,007	22,251
Gas Combustion Turbine	1,099	254	212	411	212	290	212	266	212	320	212	212	212
Oil Reciprocating	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass Combustion	-	-	-	-	-	-	-	-	-	109	-	-	-
Oil Combustion	-	-	-	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combustion	157	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	5,474	6,198	6,198	6,198	6,198	6,198	6,198	6,198	6,198	6,273	6,273	6,198	6,198
Solar PV	48	639	1,567	285	1,022	499	1,190	738	1,830	564	799	1,159	2,492
Solar PV + storage	-	-	177	-	152	-	177	-	152	-	177	532	1,090
Coal Steam Turbine	-	-	-	2,606	5,212	-	-	-	-	-	-	-	-
Wind	-	642	1,226	292	876	467	1,051	642	1,226	759	759	817	1,401
Nuclear	-	-	-	-	-	-	8,322	-	-	-	-	-	3,652
Biogas	1	1	1	1	1	1	1	1	1	1	1	1	1
Conventional Thermal	11,762	19,446	28,128	20,150	29,048	19,761	28,680	19,347	27,890	19,220	29,288	18,219	26,115
Renewable (w/L. Hydro)	5,523	7,480	9,169	6,776	8,249	7,166	8,617	7,579	9,407	7,706	8,009	8,707	11,182
Renewable (w/o L. Hydro)	49	1,505	3,194	801	2,274	1,191	2,642	1,604	3,433	1,731	2,034	2,732	5,207
% RE (w/o L. Hydro)	0%	6%	9%	3%	6%	4%	7%	6%	9%	6%	5%	10%	14%
TOTAL	**17,285**	**26,926**	**37,297**	**26,926**	**37,297**	**26,926**	**37,297**	**26,926**	**37,297**	**26,926**	**37,297**	**26,926**	**37,297**

*Note that due to the mapped year approach using the IPM modelling, the generation for the run-year 2035 is shown here, as a representative value for the longer term generation.

Figure 43: Capacity Additions for Unconstrained Strategy

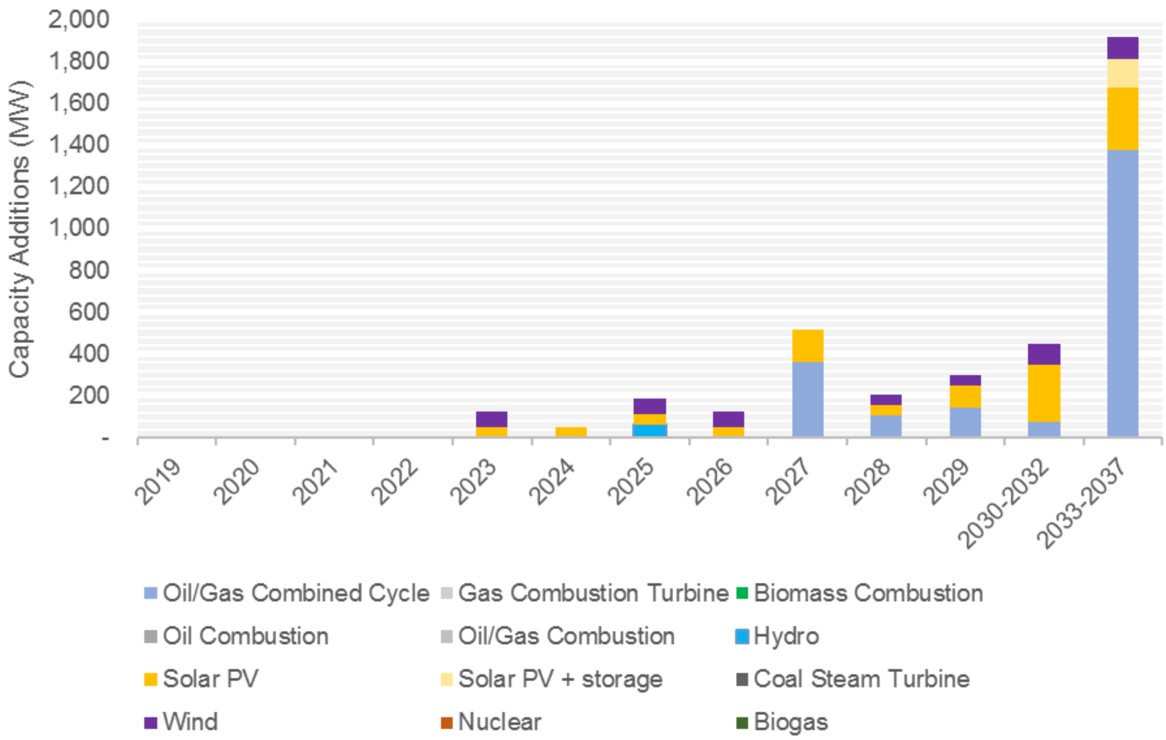
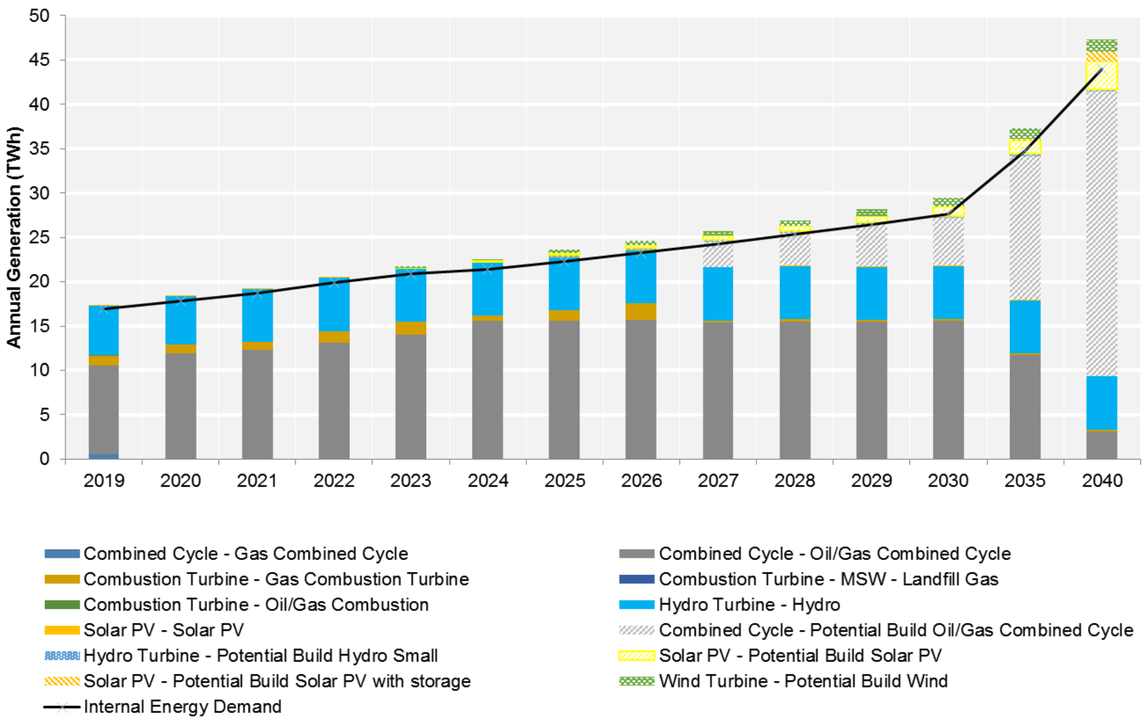
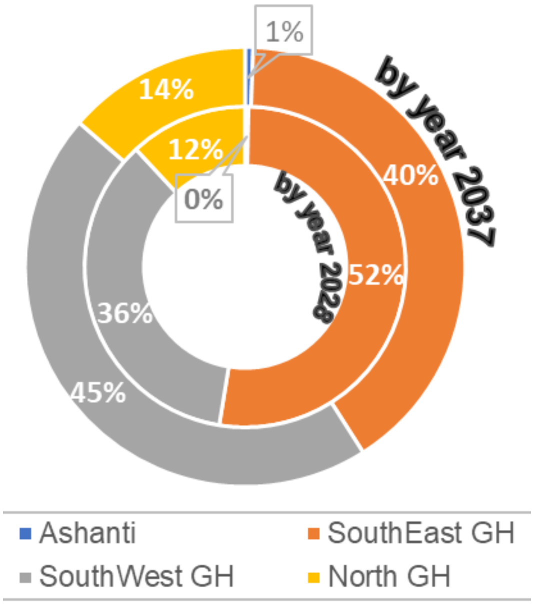


Figure 44: Annual Generation Profile for Unconstrained Strategy



As shown in Figure 44, the existing hydro and oil and gas units will continue to significantly contribute to the generation, and by 2028, existing units would contribute about 22 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 2028, the new builds contribute about 5 TWh, which increases to 19 TWh by 2035 - representing almost 51% of the total generation in that period after nearly a cumulative of about 3,870 MW capacity added on since 2019.

Figure 45: Distribution of Installed Capacity by Zones for the Unconstrained Strategy



The SouthEast GH zone has the highest share of installed generation capacity in the Ghana zones as shown in Figure 45. By the end of 2028, the share of total installed capacity in the zone is about 52%. It decreases, however, to 40% in the long term due to the addition of more plants in the SouthWestGH -primarily combine cycle plants with cumulative installed capacity of about 3300 MW. In addition, about 820MW of Solar PV plants are added in the midterm (2028) in the NorthGH zones representing about 12% of installed capacity. This increases to 14% in the ensuing years of the planning period.

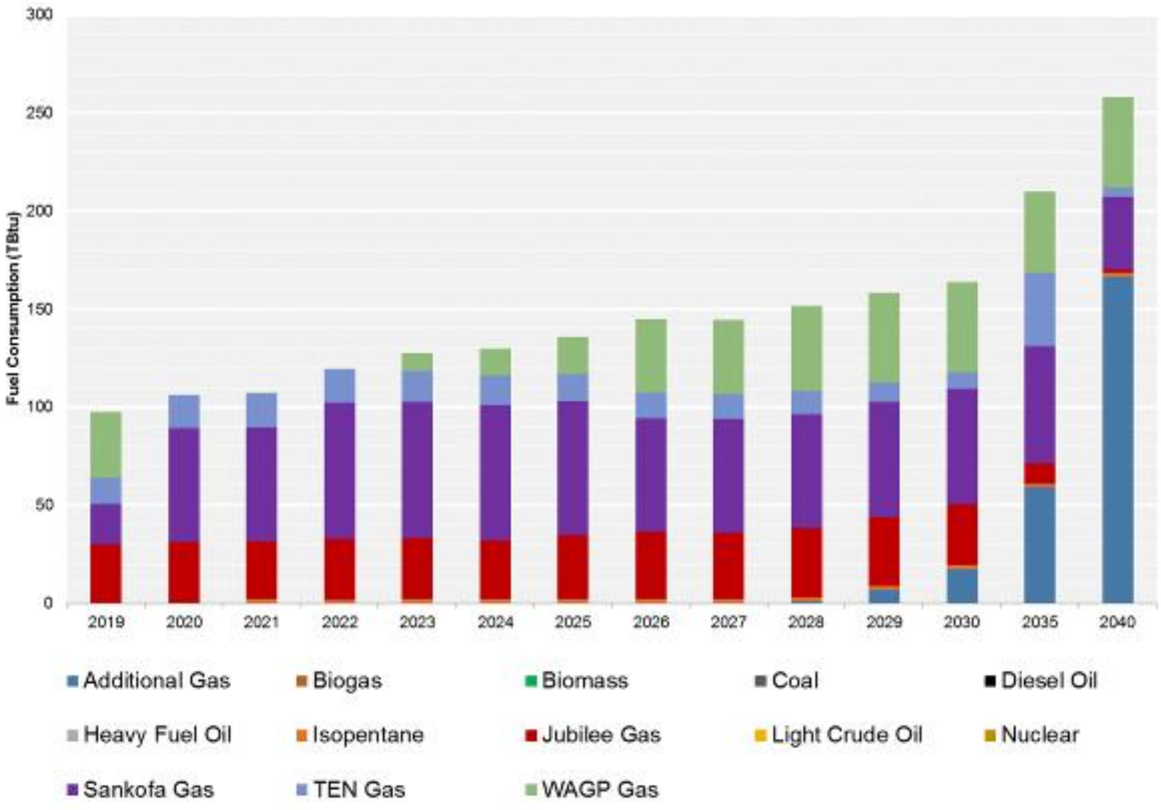
In addition, about 20 MW of solar PV capacity was added in the Middlebelt (AshantiGH zone) before 2027 with additional capacity added on in 2030. Solar PV with storage was also built in 2035.

Fuel Consumption

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 gradually reduce 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 46, 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 2 TBtu in 2029 and rose to about 59 TBtu per year by 2035. Refer to Figure 46. LNG is not consumed under the reference case electricity demand in this and all the other strategies primarily due to that fact the delivered cost of additional domestic gas from the West to East is cheaper than LNG in the East by 2028 – see Figure 35.

The cumulative volume of natural gas needed from 2019 to 2028 is about 1,265TBtu and about 1,700 TBtu between 2029 and 2037.

Figure 46: Fuel Consumed by Type in the Unconstrained Strategy



Transmission Capacity

The Unconstrained Strategy requires an upgrade in the transmission network from the SouthEastGH to NorthGH zone, the SouthWestGH to AshantiGH zone, and the SouthWest to NorthGH zone. The estimated firm transmission upgrades required for the various planning periods have been summarised in Table 37.

Table 37: Firm Transmission Upgrades Required for Unconstrained Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Span (years)	
		2019-2028	2029-2037
SouthWestGH	SouthEastGH	-	1040
SouthWestGH	AshantiGH	-	330
SouthWestGH	NorthGH	340	280

6.2.1. Diversification with Coal Strategy (Strategy II)

Generation Capacity

This supply strategy emphasizes fuel diversity by building a coal plant in SouthWest GH in two phases: 350 MW plant in 2027 and an additional 350 MW in 2030.

Given the capacity of the coal plant that comes online in the late 2020s, the timing of new generation plants as compared to the Unconstrained strategy, is pushed back from 2023 to 2026. New combustion and combined cycle gas-based power plants in this strategy is also significantly reduced by about 660MW as shown in Figure 47. See also Table 35. This illustrates the fact that if a coal plant is built by policy, the amount of gas-based power plants must be reduced. In other words, coal plants replace new gas plants in this strategy.

Figure 47: Capacity Additions for Diversify with Coal Strategy

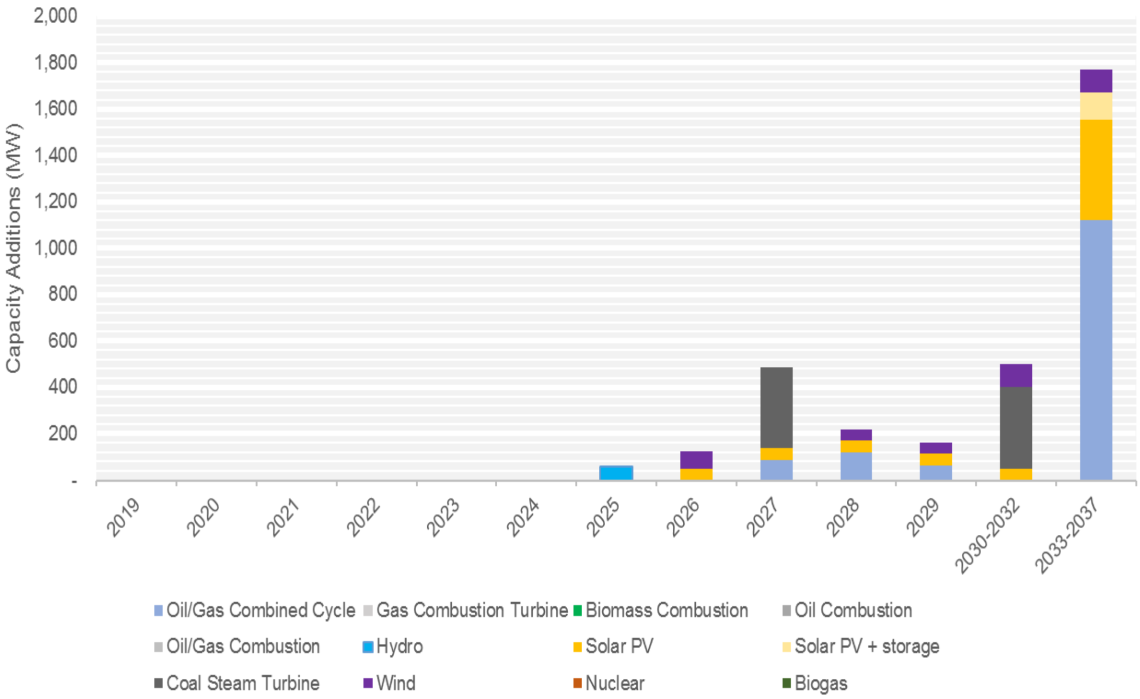
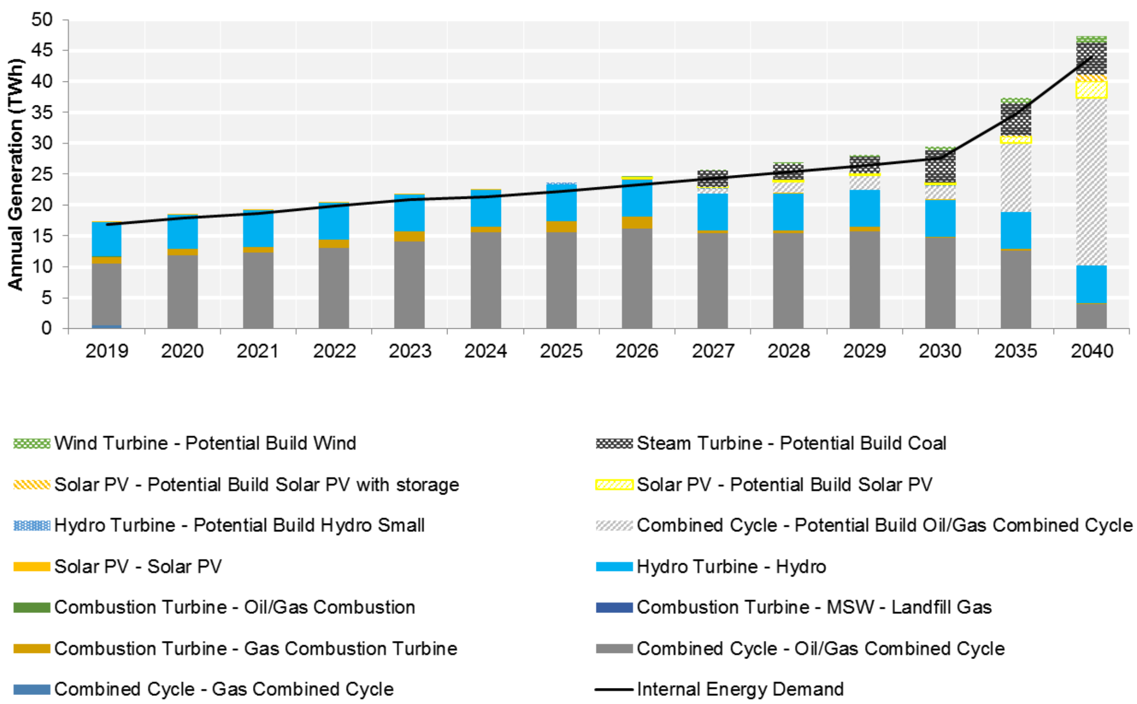


Figure 48: Annual Generation Profile for Coal Diversification Strategy



In this strategy, the existing hydro and oil and gas units continue to contribute significantly to the total on-grid generation, same as the Unconstrained case. The main difference in generation between this strategy and the Unconstrained strategy is that gas-based generation is replaced now by coal. See Figure 48. The coming online of the coal plant, adds about 2,600

GWh to the annual generation in 2027 which replaces generation from unplanned CCs plants built in the Unconstrained strategy. Cumulative generation from solar and wind is also reduced by as much as 3.1 TWh by end of 2028. However cumulative generation by end of 2028 from existing CCs and CTs increases marginally by about 2 TWh.

Figure 49: Distribution of Installed Capacity for Coal Diversification Strategy

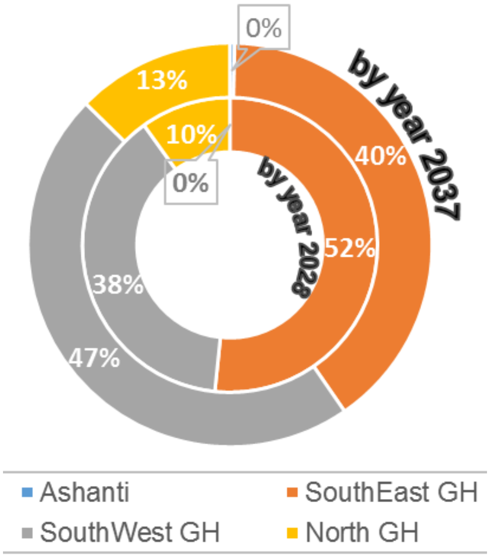


Figure 49 shows the distribution of installed capacity in this strategy across the four zones in Ghana in the shorter and longer terms. Similar to the Unconstrained strategy, there is no generation capacity in the Middlebelt zone by 2028 however this strategy requires a 30 MW Solar PV plant in 2035. Nearly all of the electricity demand for the Middlebelt area is met through transmission from North, SouthEastGH and SouthWestGH zones with a majority of it coming from the SouthWest GH Zone. In addition, there is reduced capacity addition in the north and the southeast in this strategy compared to the unconstrained strategy primarily due to the extra capacity addition in the SouthWest.

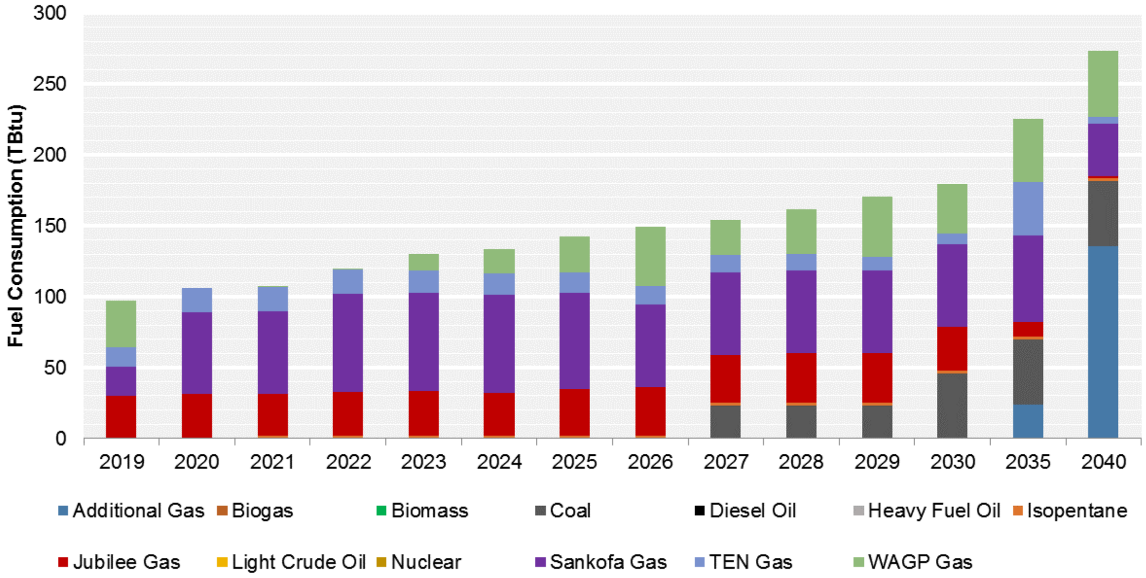
Fuel Consumption

In this strategy starts off in 2019 with about 78% (about 13TWh) of 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 reduce to about 76% by the end of 2035 primarily due to the increasing reliance on WAGP (N-Gas) and the usage of coal. Natural gas however continues to dominate as the primary fuel for electricity generation even with the introduction of coal, shown in Figure 50. Domestic gas continues to have the larger share of the gas consumed for generation, until about 2023 when the need for more volumes of WAGP (N-Gas) gradually increases from 11 TBtu in 2023 to 32 TBtu by 2028. As demand increases which give rise to increasing capacity additions, “Additional Gas” is only needed in 2035 with an annual volume of about 25 TBtu. This requirement reduces as compared to Strategy I.

Gas consumption is generally higher in this strategy than the Unconstrained in the early to mid 2020 by an average annual volume of about 4 TBtu. However, consumption of coal commences in the 2027 when the 350 MW coal plant comes online, and an additional 350 MW is added on in the early 2030s. This sees a rise in the yearly coal consumption from about 792,000 tonnes of coal equivalent (22 TBtu) per year from 2027 to 2029 to almost double the amount (1.7 million tce) by 2037. Hence, average annual gas consumption reduces by about 13 TBtu in the year the coal comes online in 2027. It slowly rises with electricity demand growth to 30 TBtu (~80 MMcfd) by the time the additional 350 MW comes on line in 2030. The implication on this is that investments in existing gas fields might become redundant especially if non-power gas demand does not materialize to make use of this excess gas.

The cumulative volume of natural gas needed from 2019 to 2028 is about 1,255 TBtu and about 1,445 TBtu between 2029 and 2037.

Figure 50: Fuel Consumed by Type for the diversification with Coal Strategy



Transmission Capacity

The diversification with coal strategy also requires some upgrades in the transmission network in order to increase the total transfer capability between these regions.. Main differences between this strategy and the Unconstrained happens in the later years after the installation of the Coal plant. The upgrades need are indicated in Table 38 below.

Table 38: Firm Transmission Upgrade Required for Coal Diversification strategy

		Strategy II _Reference Builds		Difference from Strategy I*	
Origin Transmission Region Group	**Destination Transmission Region Group**	**2019-2028**	**2029-2037**	**2019-2028**	**2029-2037**
SouthWestGH	SouthEastGH	-	1070	0	30
SouthWestGH	AshantiGH	-	210	0	-120
SouthWestGH	NorthGH	340	400	0	120

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

6.2.1. Diversification with Nuclear Strategy (Strategy III)

Generation Capacity

This supply strategy emphasizes fuel diversity by building a 1000 MW Nuclear plant in SouthWestGH in two phases: 500 MW plant in 2030 and an additional 500 MW in 2035. 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, pushes back the need for a wind plant two more years as compared to the Strategy 1. The timing of solar PV in 2023 however remain unchanged from the reference case. Although about 360 MW of CCs are still needed as early as 2027 similar to the Unconstrained strategy. However, the coming online of the nuclear reduces the capacity of solar PV by about 300 MW and that for CCs by nearly 1GW between

2023 and 2037. In essence the nuclear plant has very much replaced an equivalent capacity of CC plant. Refer to Figure 51.

Figure 51: Capacity Additions for the Nuclear Diversification Strategy

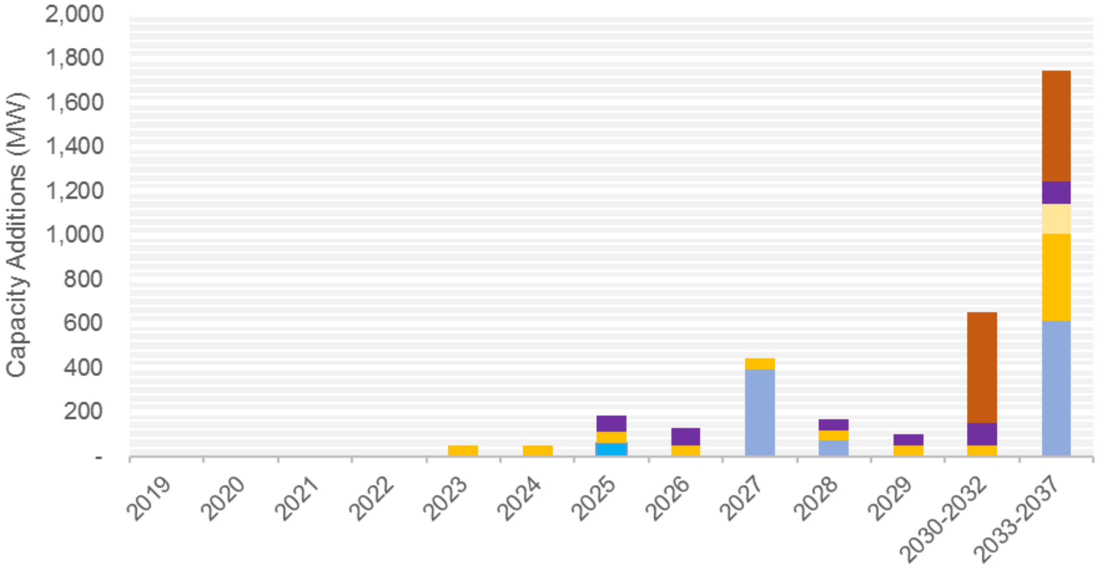
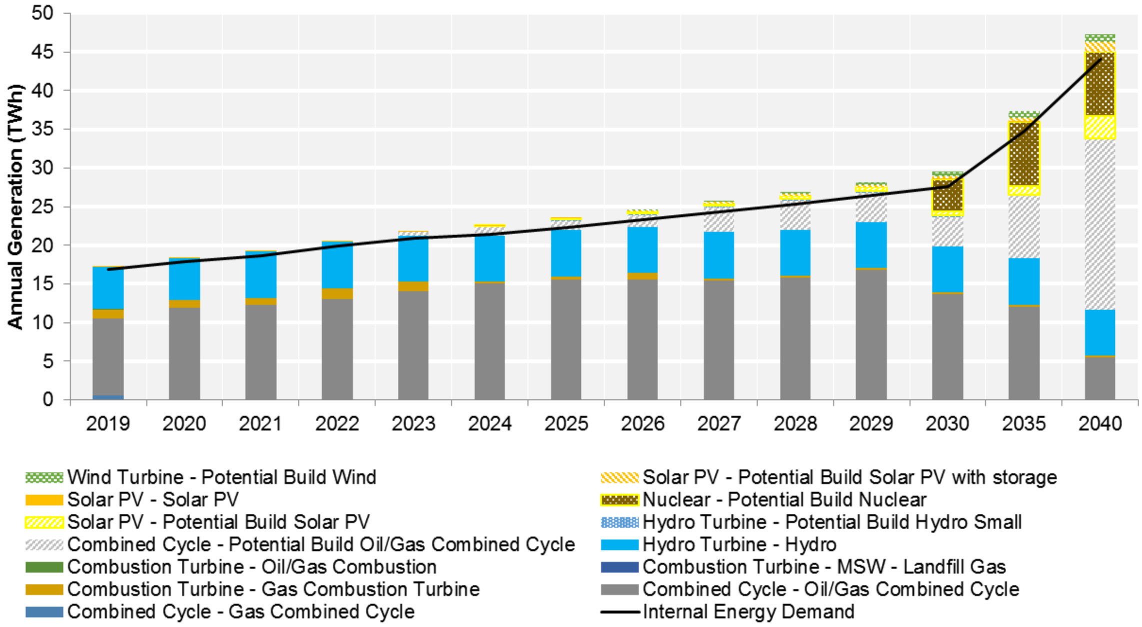
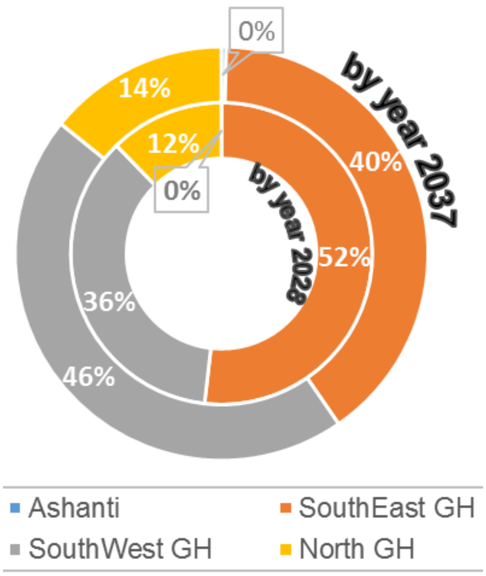


Figure 52: Annual Generation Profile for the diversification with Nuclear Strategy



The difference in generation between Strategy III 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 52.

Figure 53: Distribution of Installed Capacity for Nuclear Diversification Strategy



The nuclear plant adds about 4160 GWh to the annual generation in 2030 which increases to 8300 GWh in 2035 when the second phase comes online. The nuclear plants "takes away" the generation from existing plants and reduces it by 1740 GWh relative to the Unconstrained strategy. Cumulative generation from solar and wind is also reduced by as much as 1300 GWh by end of 2028 relative to the Unconstrained strategy.

Similar to the Strategy I and II, Strategy III has the SouthEastGH zone as the highest share of installed generation capacity, as shown in Figure 53. By the end of 2028, the share of total installed capacity in the SouthEastGH zone is about 52%, and it decreases to 40% 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 2030 and 2035. The NEDCO area also relatively increases it 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. However, similar to Strategy I and II, a 20MW and 10MW solar PV and solar PV with storage plant, respectively, is added in this region in the longer term.

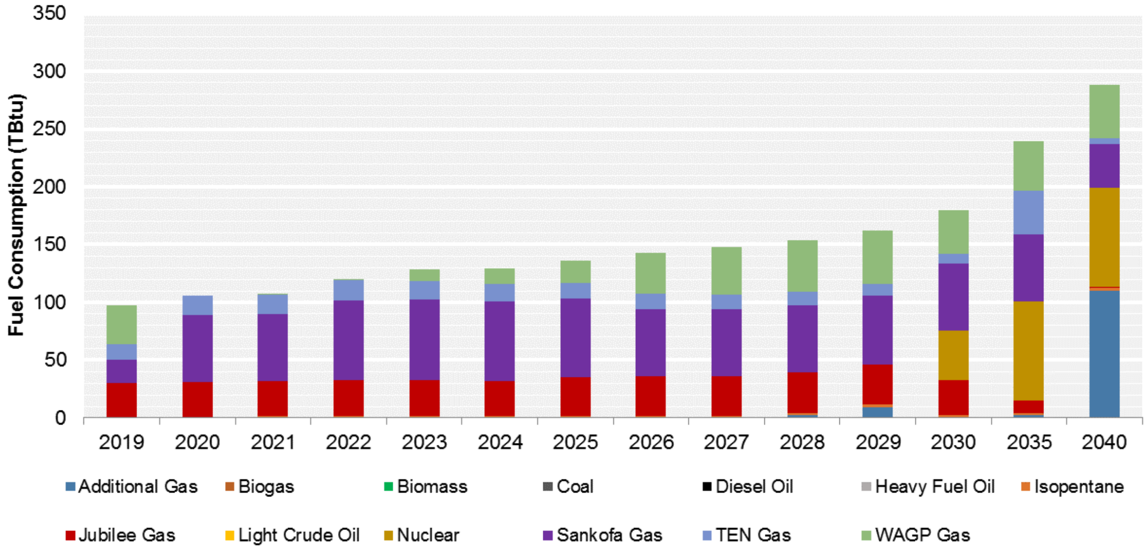
Fuel Consumption

In this strategy just as the previous strategies starts off in 2019 with about 78% (about 13TWh) of 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 reduce to about 68% by the end of 2035 primarily due to coming online of the nuclear plant.

Natural gas however continues to dominate as the primary fuel for electricity generation with uranium usage only coming in the picture in 2030 as shown in Figure 54 . Domestic gas continues to have the larger share of the gas consumed for generation (Sankofa, Jubilee, Isopentane, TEN), until about 2023 when the need for increasing volumes of WAGP (N-Gas), which gradually increases from 11 TBtu in 2023 to 45 TBtu by 2028. As demand increases which give rise to increasing capacity additions, "Additional Gas" TBtu is needed in small quantities in 2028 (2 TBtu) and rises to about 10TBtu when the maximum volume of N-Gas (~123 MMcfd/46 TBtu) was reached. However due to the introduction of a nuclear plant in 2030, the quantity gas needed for generation reduces by as much as 70 MMcfd and this reduction more than doubles to about 150 MMcfd in 2035. And similar to the coal strategy, existing gas fields might become redundant if non-power use of gas does not materialize to make use of this excess gas.

The cumulative volume of natural gas needed from 2019 to 2028 is about 1,275 TBtu and about 1,340 TBtu between 2029 and 2037 compared to the 1265 TBtu and the 1700 TBtu respectively realised in the Unconstrained strategy.

Figure 54: Fuel Consumed by Type for the diversification with Nuclear Strategy



Transmission Capacity

This strategy also requires a significant upgrade in transmission network from the SouthWestGH to the Middlebelt, SouthWestGH to NorthGH zone, and SouthWestGH to the SouthEastGH zone. Details of the estimated transmission upgrades needed for from 2019 to 2037 are indicated in Table 39. The table also shows the difference in the transmission upgrade from the Unconstrained strategy.

Table 39: Transmission Upgrades Required for Nuclear Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy III _Reference Builds		Difference from Strategy I*	
		2019-2028	2029-2037	2019-2028	2029-2037
SouthWestGH	SouthEastGH	-	1060	0	20
SouthWestGH	AshantiGH	-	270	0	-60
SouthWestGH	NorthGH	340	340	0	60

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

6.2.2. Diversification of Geographic Location Strategy

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. In this strategy it is assumed that the gas pipeline to Kumasi has been completed by 2027 which the plant uses as its main fuel source. Result from the reference assumptions, indicate that the plant is economically dispatched and maintains a capacity factor of 90% from 2027 through to 2035 when it drops to 65%. On the whole this strategy under reference assumptions performs the 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.

Figure 55: Capacity Additions - Diversification of Geographic Location Strategy

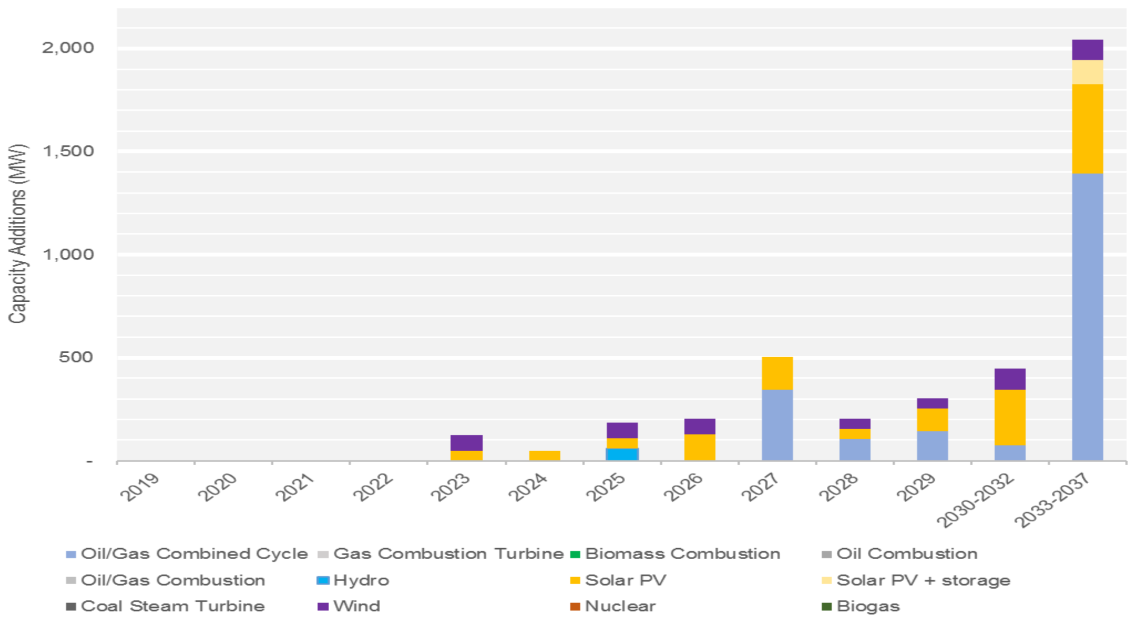
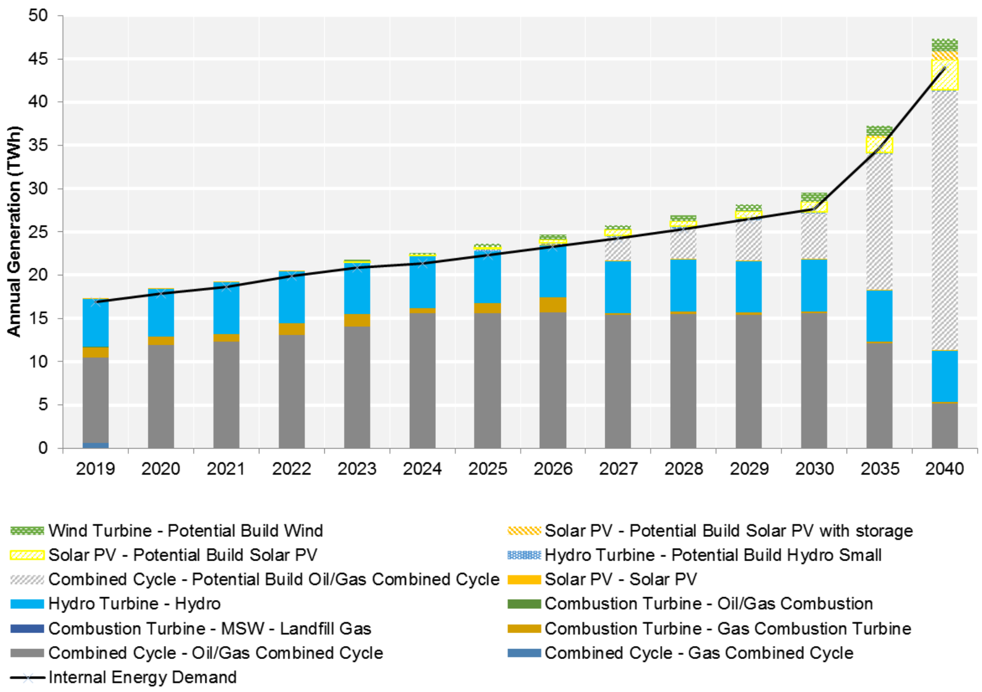


Figure 56: Annual Generation Profile - Diversification of Geographic Location Strategy



Besides the CC built in the AshantiGH zone, the main difference between the Unconstrained strategy and this strategy in terms of build pattern is the extra 200MW this strategy builds in the AshantiGH, SouthWest and SouthEast zone.

There are no significant differences between this strategy and the Unconstrained strategy, with the only difference being the extra 80 MW and 130 MW solar capacity added in this strategy in 2026 and 2035 respectively. See Figure 55 and Figure 56.

Figure 57: Distribution of Installed Capacity for Geographic Diversification Strategy

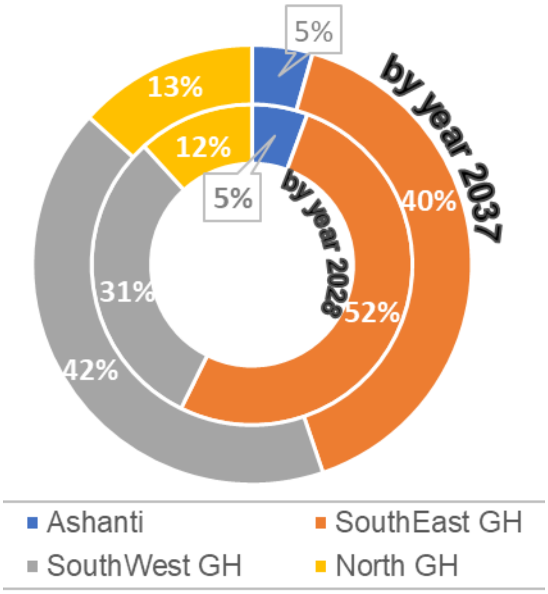
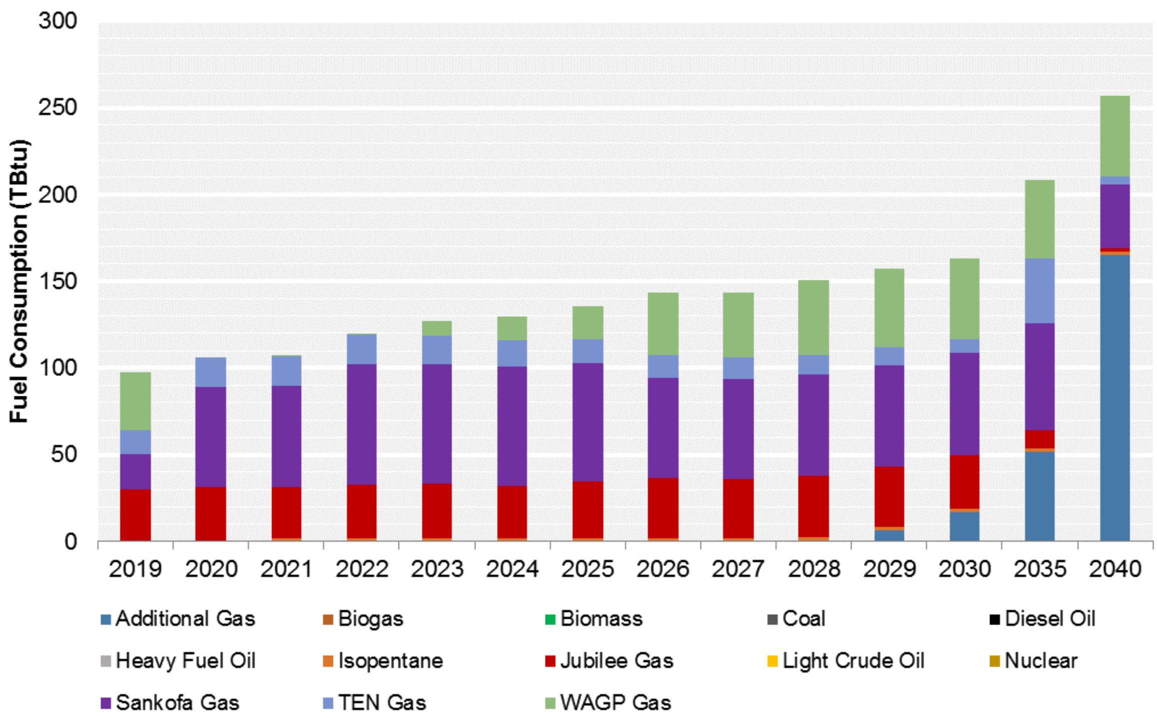


Figure 57 shows the distribution of installed capacity in this strategy across the four zones in Ghana in the shorter and longer terms. This strategy by far has the highest share of installed capacity in the middle belt (AshantiGH zone). With Ashanti recording 5% throughout the planning period, there is bound to be the added cost benefit of transmission loss reduction in this strategy which has not been captured in this version of the IPM. Another difference between this strategy and the Unconstrained strategy is the reduced installed capacity in SouthWest.

Fuel Consumption

Annual generation from domestic fuel sources - primarily domestic gas and renewables including large hydro- being able to meet domestic net demand was at 78% in 2019 and increases to 100% in the subsequent years and gradually reduces to about 91% by the end of 2035. However, the average over the planning period is about 92%.

Figure 58: 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 2019 to 2028 being about 1,260 TBtu and about 1,690 TBtu between 2029 and 2037 which 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,TEN), until about 2023 when there is need for increasing volumes of WAGP (N-Gas), which starts off from an annual consumption of about 9 TBtu in 2023 to about 45TBtu by 2028. As demand increases which give rise to increasing capacity additions, “Additional Gas” TBtu is needed in small quantities starting in 2028 (< 2 TBtu) and rises to about 51 TBtu in 2035.

Transmission Capacity

This strategy also requires upgrades in the transmission network from the SouthWest to NEDCo are, the middle belt and the SouthEast. The details for the estimated total transmission upgrades for the 10-year and the long term periods are indicated in Table 40. The table also shows the difference in the transmission upgrade from the Unconstrained strategy. Comparatively this strategy requires less transmission upgrades in the SouthWestGH to AshantiGH when compared with the transmission upgrade requirement in the Unconstrained strategy. This is mainly because of the 300 MW of CC installed in the AshantiGH zone and would be meeting a significant portion of the local demand.

Table 40: Transmission Upgrades for Geographic Diversification Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy IV _Reference Builds		Difference from Strategy I*	
		2019-2028	2029-2037	2019-2028	2029-2037
SouthWestGH	SouthEastGH	-	1040	0	0
SouthWestGH	AshantiGH	-	70	0	-260
SouthWestGH	NorthGH	210	370	-130	90

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

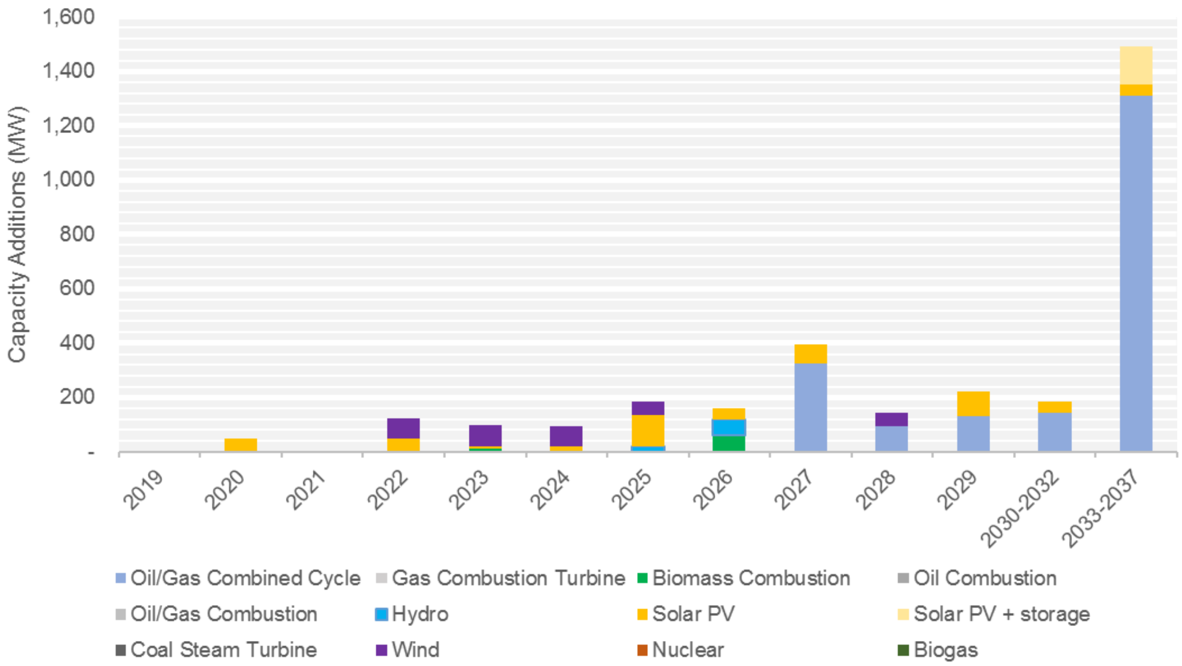
6.2.3. Renewable Energy Master Plan (REMP) – STRATEGY V

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.

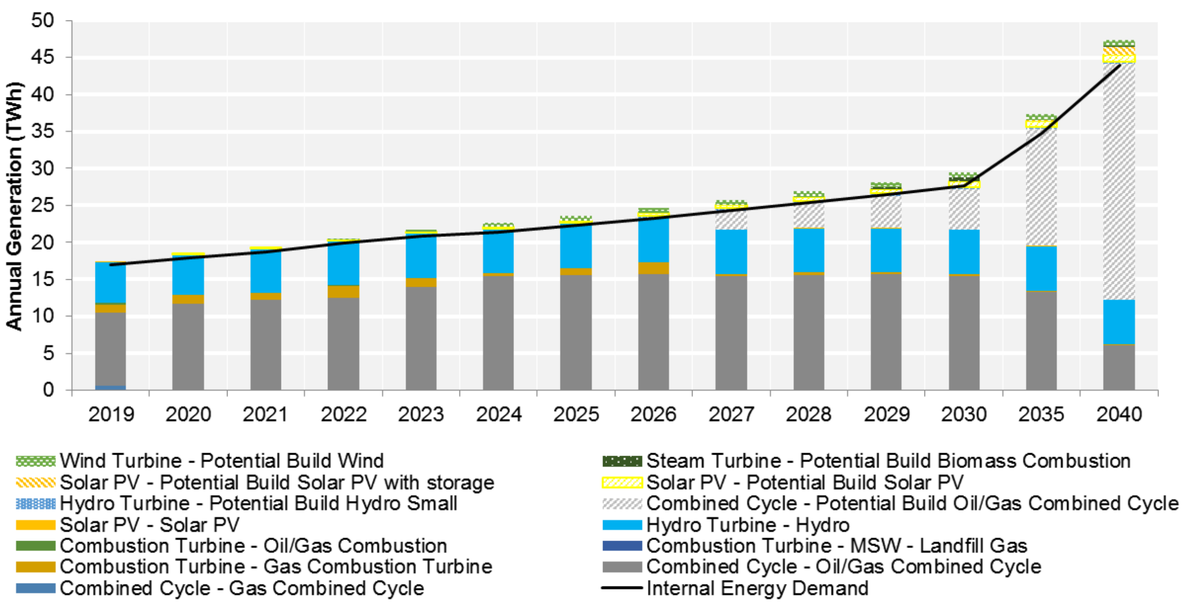
Compared to the Strategy I, capacities come on earlier, with about 50MW of solar PV coming online as early as 2020. However, relatively small capacity of PVs come online in subsequent years and is cumulatively less over the study period than the Unconstrained strategy by about 560MW. A 12MW biomass plant is also built in 2023 including an additional 20MW small hydro is added to the 60MW plant which is in all the strategies. The timing of CCs comes online at much the same time as the Unconstrained strategy and with similar cumulative capacities of about 2000 MW. Refer to Figure 59.

Figure 59: 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 remains the same. By 2028, gas generation represents about 71% of total demand with renewable including large hydro representing just 29% (and about 6% without large hydro).

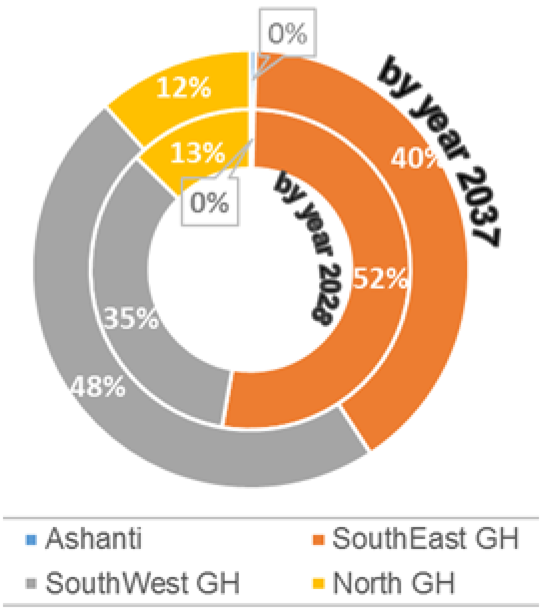
Figure 60: Annual Generation Profile for the REMP Strategy



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 of gas generation units to 79% by 2037 whilst the percentage of RE generation in the energy mix with the inclusion of large hydropower reduces to 21% with large hydro and 5% without. In comparison, the Unconstrained strategy had relatively more generation from REs, with the percentage of

RE generation without large hydro within the 10year and the longer term being 6% and 9% respectively. See Table 36 and Figure 61 for the generation pattern for this strategy.

Figure 61: Distribution of Installed Capacity by Zones for the REMP Strategy

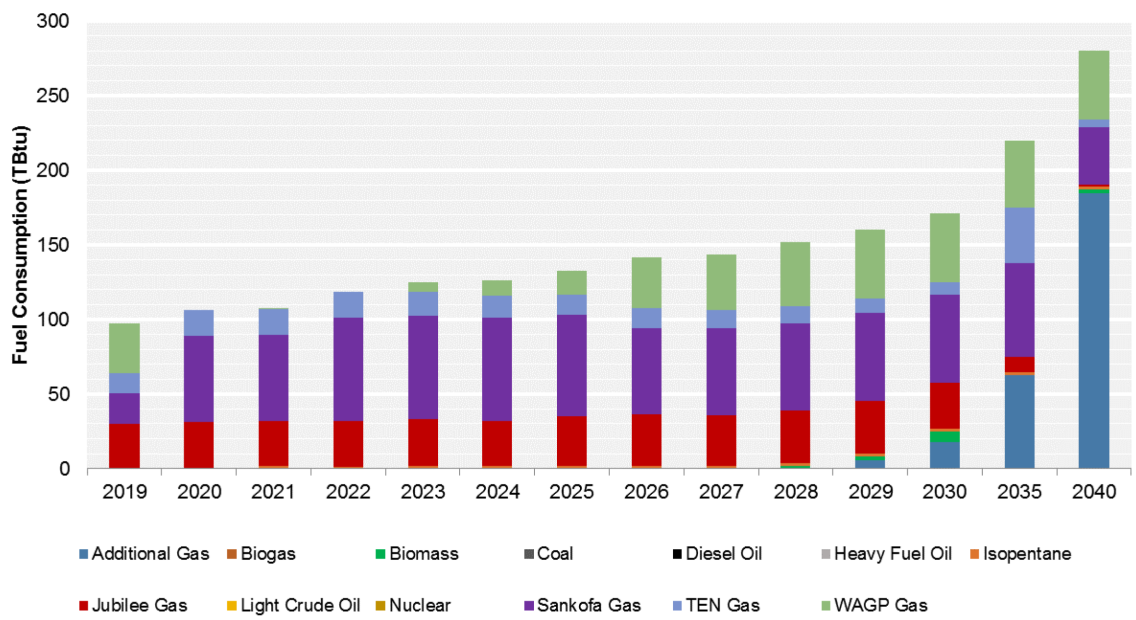


This strategy has relatively less builds in the SouthWest and more in all the other zones than the Unconstrained strategy. The share of installed capacities across the zones in 2019 is about 63% in the SouthEast, 31% in the SouthWest and about 6% in the North. However, this changes with time, as more 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 plant. The Middle-belt region, however, only sees the addition of a biomass plant and a solar PV equalling about 22 MW which represents less than 1% of the total generation capacity for the whole of the Ghana.

Fuel Consumption

On the average, across the planning period, about 93% 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.

Figure 62: 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 2019 to 2028 being about 1,250 TBtu and about 1,750 TBtu between 2029 and 2037 which is not significantly different from the Unconstrained strategy which requires 1265 TBtu and 1700 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 generation until about 2023 when there is need for increasing volumes of WAGP (N-Gas), which starts off from an annual consumption of about 6 TBtu in 2023 to about 43 TBtu by 2028. As demand increases which give rise to increasing capacity additions, “Additional Gas” is needed in small quantities starting in 2029 (~ 6 TBtu) and rises to about 63 TBtu in 2035.

Transmission Capacity

This strategy requires relatively less transmission upgrade in transmission network than the other strategies. The upgrades required are for only the SouthWest-to-SouthEast and the SouthWest-to-North corridors. Practically little or no upgrade is required on the SouthWest-to-Ashanti path, which was required in almost all other strategies, because of the new RE builds in the region.

The estimated transmission upgrades for the transmission paths are indicated in Table 41.

Table 41: Transmission Upgrades Required for the REMP Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy V Builds		Difference from Strategy I*	
		2019-2028	2029-2037	2019-2028	2029-2037
SouthWestGH	SouthEastGH	-	1080	0	40
SouthWestGH	AshantiGH	-	-	0	-330
SouthWestGH	NorthGH	245	610	-95	330

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

6.2.4. Enhanced G-NDC – STRATEGY VI

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 capacity in the short-to-medium term. This strategy requires a new 75 MW wind plant to come online in the early 2022s, which was not needed in the Unconstrained strategy. Compared to the Unconstrained strategy, and extra 730 MW of solar PV comes online, a significant increase in installed capacity of solar with storage is seen (over 860MW compared to 160MW in Unconstrained strategy). The solar with storage unit have potentially replace some of the CCs which were seen in the Unconstrained strategy. Refer to Figure 63 for capacity additions in this strategy.

Additionally, this strategy adds on a 440 MW nuclear plant in the mid-2030s, in order to meet the more stringent CO_2 emissions growth.

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 64 and Figure 65.

Same as with the previous strategies, the characteristics of the existing hydro and oil and gas units’ contribution remains the same. By 2028 generation from thermal units (gas) represented about 68% of total generation with renewable including large hydro making up the rest at 32% (without large hydro RE was about 11%).

However, as demand grows, there is a need for new generation units to provide for both peak and energy, hence the addition of more solar PV and solar with storage plants as compared to the Unconstrained strategy, thus increasing the percentage of RE in the generation mix to about 39% with the inclusion of large hydropower generation and about 24% when large hydro is excluded. See Figure 66 for the generation pattern for this strategy.

Figure 63: Capacity Additions for the Enhanced G-NDC Strategy

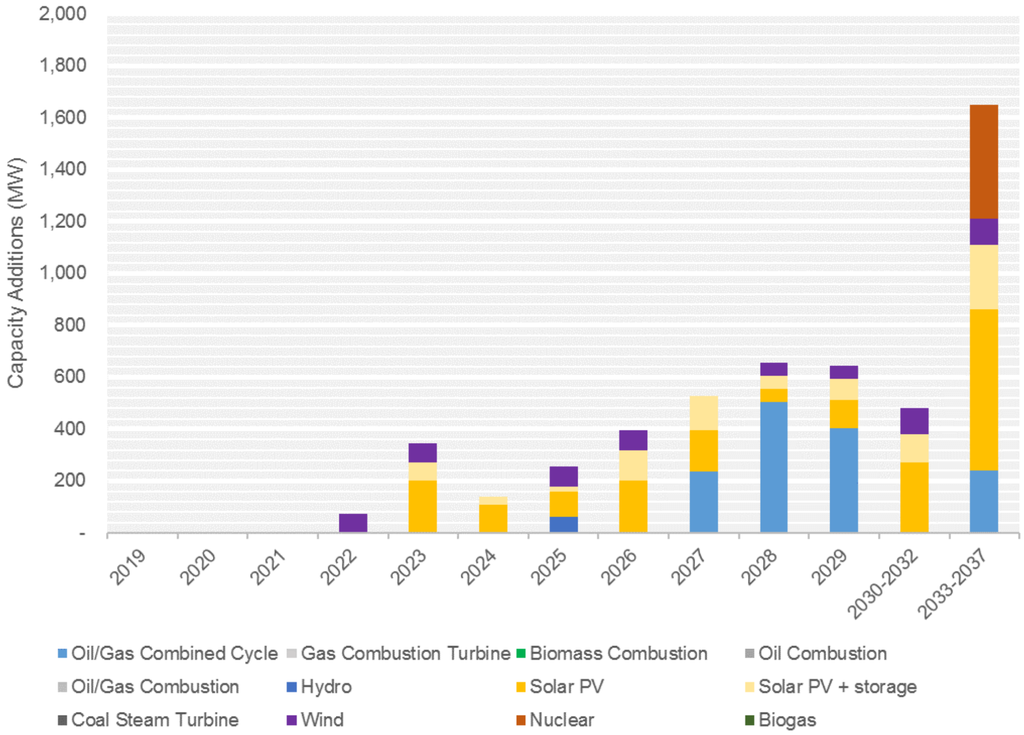


Figure 64: Total CO2 Emission for all Strategies

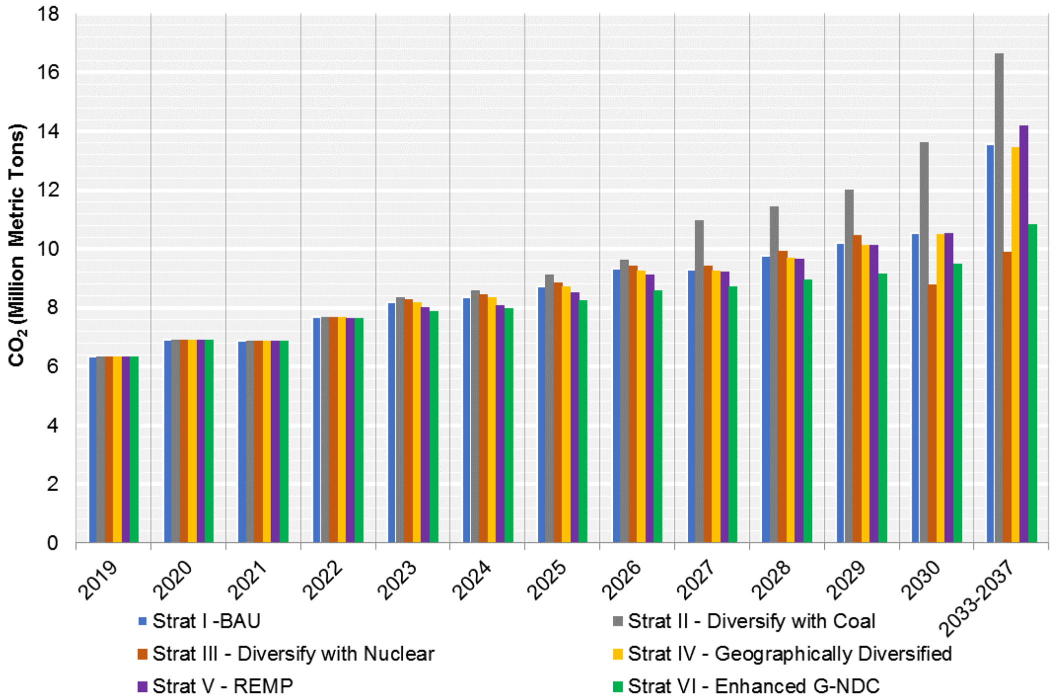


Figure 65: Comparison of CO2 Intensity for all Strategies

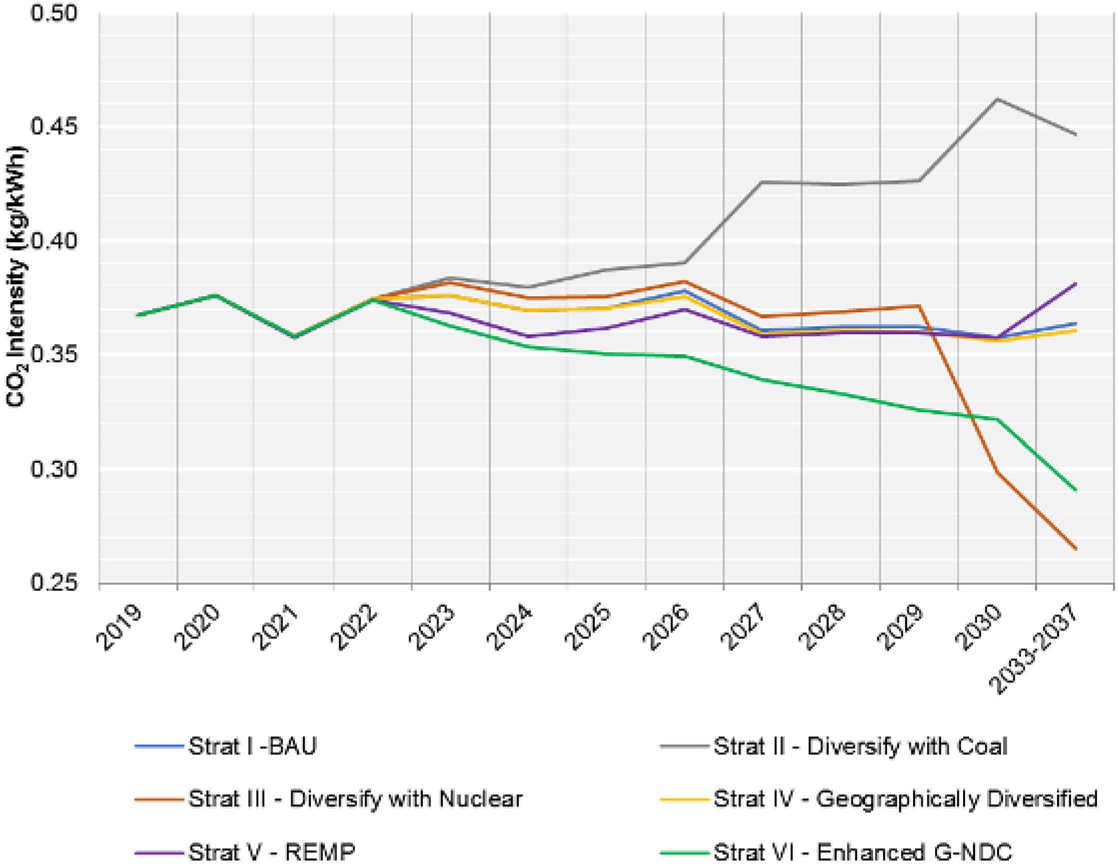


Figure 66: Annual Generation Profile for the Enhanced G-NDC Strategy

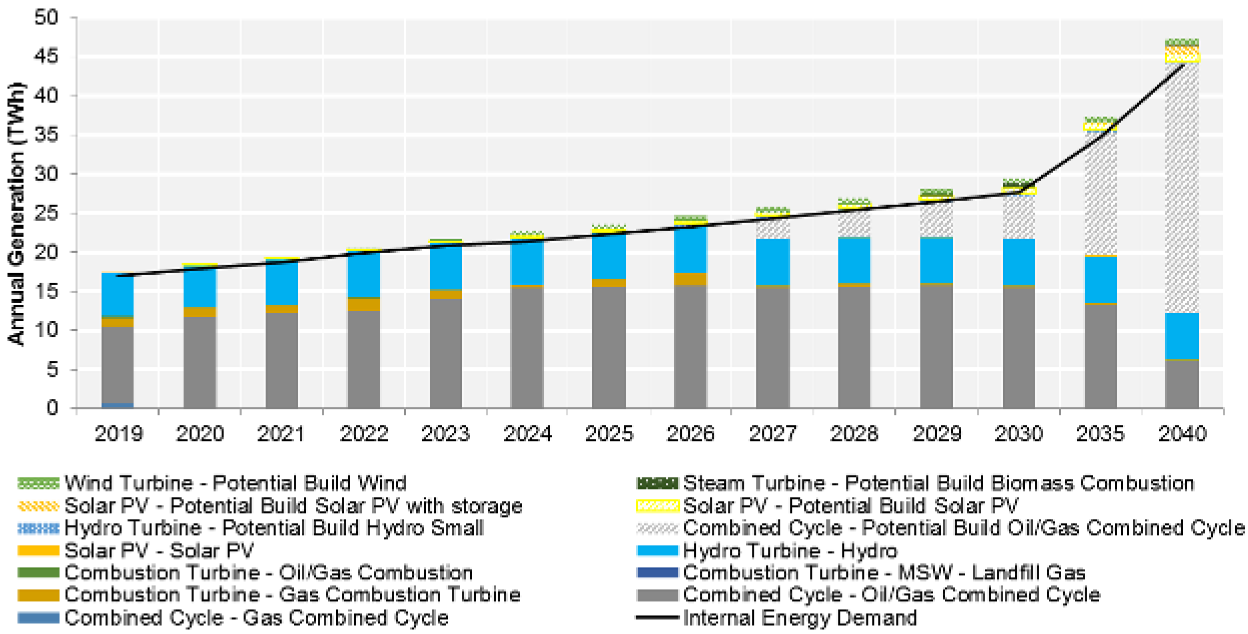
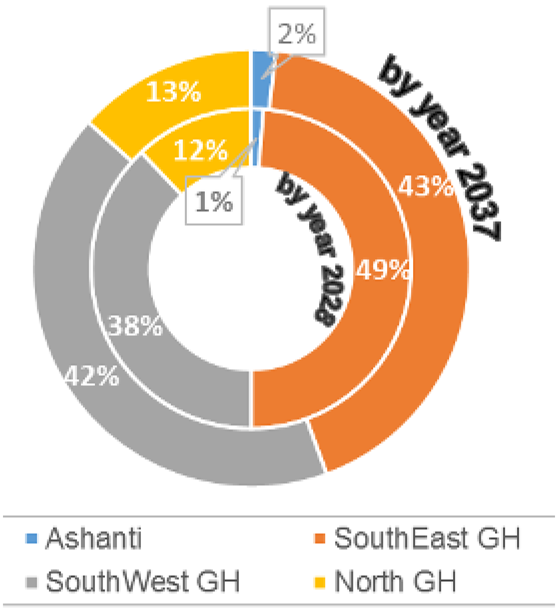


Figure 67: Distribution of Installed Capacity for Enhanced G-NDC Strategy



The share of installed capacities across the zones in 2019 is about 63% in the SouthEast, 31% in the SouthWest and about 6% in the North. However, just like the previous strategies, the distribution across the zones changes with time as indicated in Figure 67. More capacities are added in the SouthWest, and the capacity even in Ashanti Zone increases to about 2% by 2037.

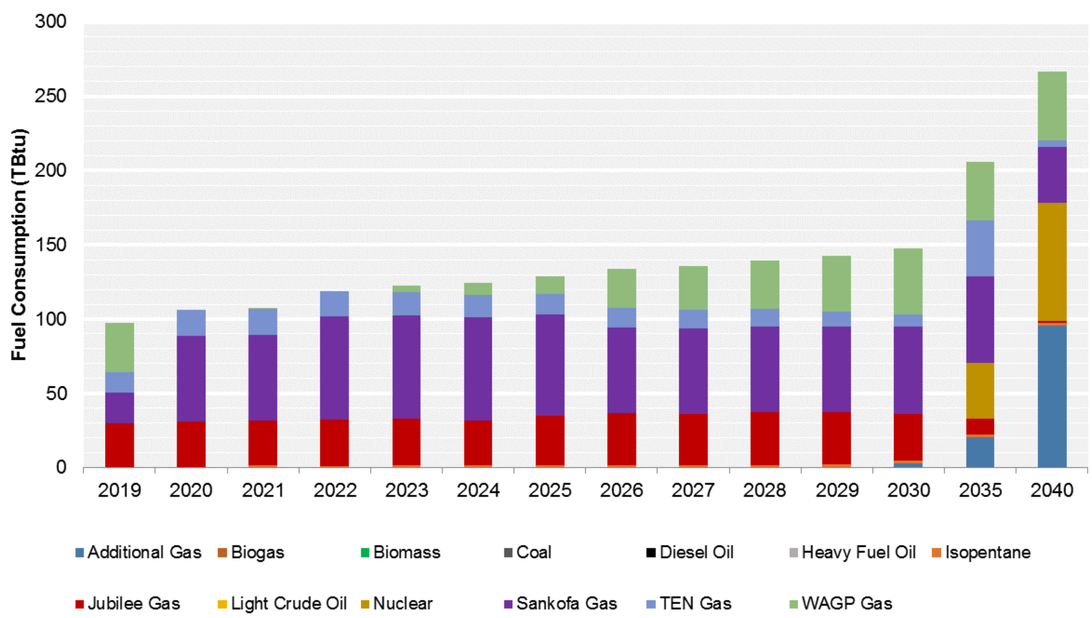
For the north zone, more solar PV units are added which increase from 6% to 12% and then 13% for 2019 to 2028 then to 2037 respectively.

<u>Fuel Consumption</u>

On the 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.

Natural gas continues to dominate as the primary fuel for electricity generation with cumulative volume needed between 2019 to 2028 being about 1,215 TBtu and about 1,425 TBtu between 2029 and 2037 which is relatively lower than gas requirement for the unconstrained due to the availability of alternative fuel used by the nuclear plant.

Figure 68: Fuel Consumed by Type for the Enhanced G-NDC Strategy



Domestic gas has the larger share of the total gas consumed for generation until about 2023 when consumption of WAGP (N-Gas) starts increasing from an annual consumption of about 4 TBtu in 2023 to about 32 TBtu by 2028 with the maximum consumption at 44 TBtu in the early 2030s. As demand increases which give rise to increasing capacity additions, "Additional

Gas" is only needed in very small quantities starting in 2030 (~ 3 TBtu) and rises to about 20 TBtu in 2035. Reductions in gas consumption can be attributed to the coming online of the 420 MW nuclear unit in the mid-2030s.

Transmission Capacity

This strategy also requires some upgrades to the SouthWest to SouthEast, the SouthWest to Ashanti and the SouthWest to North transmission corridors. There are no significant differences between this strategy and the unconstrained, except the relatively less upgrades required in the later period between the SouthWestGH and SouthEastGH transmission corridor. This 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 42.

Table 42: Transmission Upgrades Required for the Enhanced G-NDC Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Strategy VI _Reference Builds		Difference from Strategy I	
		2019-2028	2029-2037	2019-2028	2029-2037
SouthWestGH	SouthEastGH	-	940	-	-100
SouthWestGH	AshantiGH	-	360	-	30
SouthWestGH	NorthGH	280	250	-60	-30

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

6.3. 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 32 of Section 6.2) were fixed for the entire planning period, and these results were then "tested" over the full range of sensitivities (see Table 33). 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 43 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 69 to Figure 72**.** They represent the cumulative investment costs and cumulative total system costs metrics for each of the five strategies. Figure 69 and Figure 70 shows the cumulative overnight investment costs for each strategy, across the sensitivities which affects the investment cost, over the 10-year and 19-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 as the most reasonable value to use for comparison across the strategies. See Table 44 for a summary of all the strategies for both 10- and 19-year periods.

The Enhanced G-NDC (Strategy VI) portfolio seems to be the worst performing strategy in terms of total investment cost for both the 10 year and the 19 year period. As expected, the total investment cost for both medium and long term period for all the strategies were very sensitive to high demand (see Figure 69 and Figure 70) especially for Strategy VI.

For the cumulative total system cost, as presented in Figure 71 and Figure 72, 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 $10.9 billion, which was about $370 million USD lower than the second lowest strategy which is the Diversify with Nuclear strategy. The diversification with nuclear appears to be cheaper in the shorter term (10years) primarily due 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 second placed in terms of having the second lowest investment and system cost in the long term, even with the relatively high delivered cost of gas to the 300MW CC plant 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. This can be studied in future updates.

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 19-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 10years. However, the results of this metric – which is presented as the average between 2019 to 2037, indicate the worst performing strategy to be strategy II and III. Even though the difference between these two and the other strategies under this metric is not significant, Strategy VI comes out as the best performing having recorded an average of about 8 MW. There was also not much difference in the transmission congestion metric across all the strategies, however Strategy V comes off the best performing the metrics. See Table 44.

In general, however, Strategy VI 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 has been ring-fenced (apart from the demand sensitivities), Strategy VI is likely to perform relatively better under the given assumptions and constraints. See Table 44.

Table 43: Metrics for 10 Years (2019–2028) 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 Conv. CapCost	AVERAGE
Total Capital Cost	*M USD*	216	216	216	216	216	216	216	216	249	183	198	**215**
Total System Cost	*M USD*	6,745	8,456	6,374	7,521	5,945	6,611	6,745	6,845	6,778	6,712	6,726	**6,860**
Unserved Peak	*MW*	0	196	0	0	0	0	0	0	0	0	0	**18**
Transmission Congestion	*%*	29%	27%	25%	26%	26%	26%	26%	26%	27%	27%	27%	**26%**
Resource type diversity [Domestic Fuel]	*%*	92%	81%	97%	92%	92%	86%	92%	91%	92%	92%	92%	**91%**
Local Reserve (Ashanti & North)	*%*	42%	49%	46%	42%	42%	42%	42%	42%	42%	42%	42%	**43%**
Air Quality (Sox, Nox)	*Thousand Tons*	63	85	57	63	63	62	63	65	63	63	63	**65**
GHG	*Thousand Tons*	8,147	10,904	7,364	8,147	8,150	8,030	8,147	8,311	8,147	8,147	8,147	**8,331**
Ash Production	*Thousand Tons*	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	**0.02**
Land requirements	*Acres*	120,207	120,207	120,207	120,207	120,207	120,207	120,207	120,207	120,207	120,207	120,207	**120,207**

Table 44: Average across Sensitivities for 10- and 19-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC		RESILIENCE METRIC		LOCAL ENVIRONMENTAL METRIC		LAND USE	CLIMATE METRIC
	Total Capital Cost *M USD*	Total System Cost *M USD*	Trans. Congest-ion *%*	Unserved Peak *MW*	Local Reserve (AshantiGH & NorthGH) *%*	Resource type diversity [Domestic Fuel/Domestic Demand] *%*	Air Quality (Sox, Nox) *Thousand Tons*	Ash Production *Thousand Tons*	Land requirement *Acres*	GHG *Thousand Tons*
2019-2028										
Strat I -Unconstrained	215	6,860	26%	18	43%	91%	65	0	120,207	8,331
Strat II – Diversify with Coal	248	6,955	26%	19	43%	89%	66	38	117,854	8,776
Strat III – Diversify with Nuclear	186	6,861	27%	18	43%	90%	65	0	119,016	8,410
Strat IV – Geographically Diversified	224	6,890	27%	17	49%	91%	65	0	120,516	8,316
Strat V – REMP	355	6,968	26%	16	46%	92%	64	1	159,158	8,216
Strat VI – Enhanced G-NDC	370	6,910	26%	16	44%	93%	61	0	124,333	7,922
2029-2037										
Strat I -Unconstrained	1052	10,923	18%	9	37%	90%	66	0	126,200	10,297
Strat II – Diversify with Coal	1502	11,436	18%	10	37%	83%	66	188	123,382	11,918
Strat III – Diversify with Nuclear	1666	11,294	18%	10	37%	83%	62	0	124,005	9,127
Strat IV – Geographically Diversified	1080	11,023	18%	9	51%	90%	66	0	126,873	10,256
Strat V – REMP	1239	11,181	18%	9	42%	90%	67	2	160,775	10,399
Strat VI – Enhanced G-NDC	1713	11,208	18%	8	40%	89%	57	1	132,305	9,091

Figure 69: Total Investment Cost Metric across sensitivities for 10-Year Planning Horizon

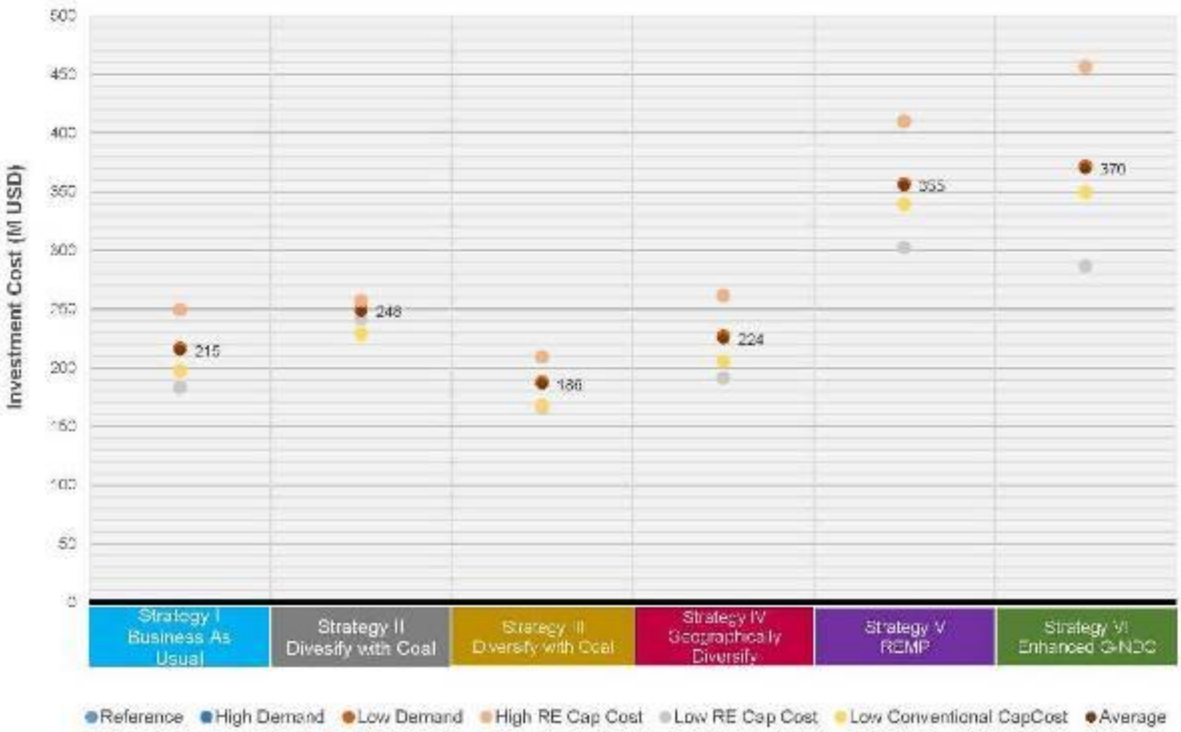


Figure 70: Total Investment Cost Metric across sensitivities for 19-Year Planning Horizon

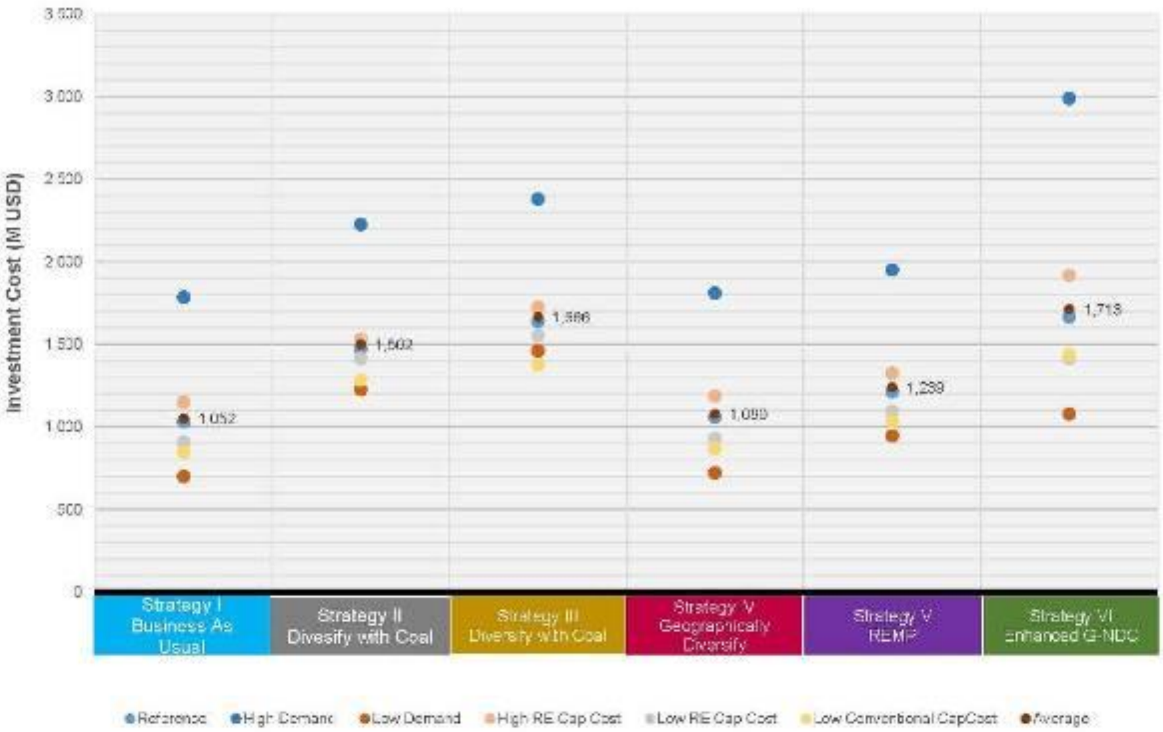


Figure 71: Total System Cost Metric across sensitivities for 10-Year Planning Horizon

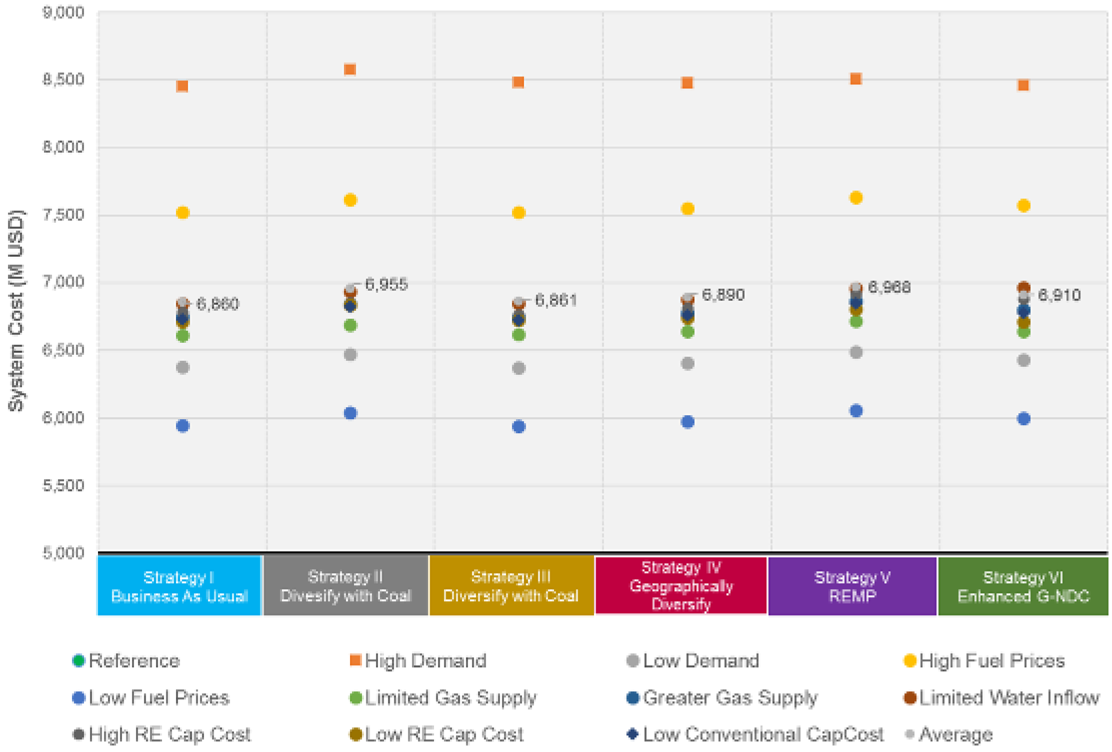
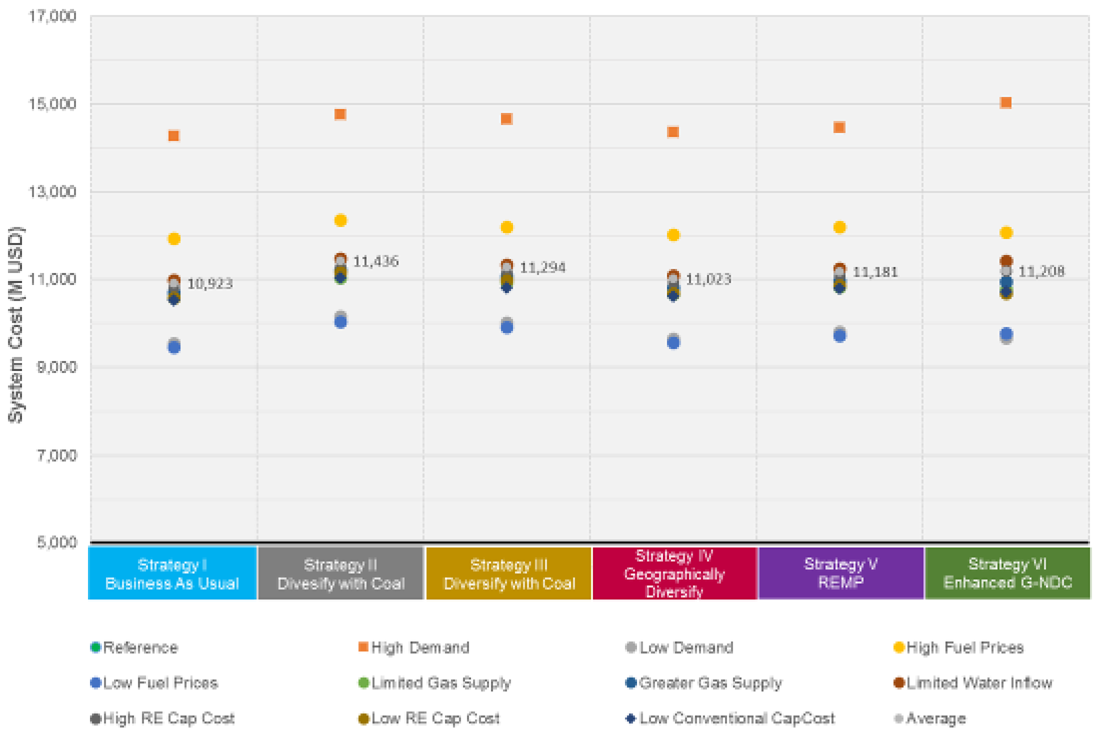


Figure 72: Total System Cost Metric across sensitivities for 20-Year Planning Horizon



Resilience: For the broader theme of resilience, the metrics identified here are the local reserve capacity (for the Ashanti and NorthGH zones) and the share of generation from locally available fuels used in meeting domestic demand. Over the 19-year period, Strategy IV (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 19-year period recording about 51%.

Under the local resource metric, Strategy V(REMP) performed the best over the entire study period, being the strategy with the least imported fuels and relying a lot on renewable sources of generation, however in the shorter run (10-year) strategy VI seem to the strategy utilizing the most local fuel resource to meet local demand. Overall, under the resilience metric, the combination of the scores from both the local reserves capacity metric and the local resource diversity metric, indicate Strategy IV as the best performing strategy under this metric for both the 10-year and the 19-year period. See Table 47.

Local environmental metric: The best performing strategy under the local environmental metric is the Strategy VI (Enhanced G-NDC Strategy) in both the 10-year and the 19-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 the construction of two small hydro plants. However, Strategy II has the least footprint per MW of capacity addition largely due to the coal 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 9,000metric tons over the 19-year period.

6.4. Least-Regrets Portfolio

The consensus decision of the IRRP Steering and Technical Committee members was to assign the cost metric a much higher priority than all the other metrics. Therefore, the methodology adopted to determine the Least-Regrets Strategy was to first select the highly ranked strategies under the cost metrics (i.e., those with low cost values), then evaluate these strategies against a combined metric of all the other strategies to identify the least-regret 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 45 and Table 47, which shows the ranking for the various strategies across all the metrics for the 10- and 19-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 46.

Similar rating 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 45 to Table 48.

The analysis shows that the Unconstrained Strategy (Strategy I) is the least cost, and it also performs relatively well under all the other metrics for the whole 19 year planning period. Hence, the Unconstrained Strategy is deemed as the most favourably ranked strategy in terms of cost and performance of all other metrics, relative to the other strategies, and therefore it qualifies as the *Least-Regrets* Strategy for the 2019 IPSMP update. The strategy is largely characterized by development of renewables and combined cycle plants, with some appreciable level of transmission upgrades. This is similar to the Least Regret strategy in the 2018 IPSMP as well. The specific build portfolio for the 2019 Least-Regrets Strategy is shown in Figure 73.

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 45: Ranking of the Strategies for 10-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC		RESILIENCE METRIC		LOCAL ENVIRONMENTAL		LAND USE	CLIMATE METRIC
	Total Capital Cost	Total System Cost	Transmission Congestion	Unserved Peak	Local Reserve (Ashanti&North)	Resource type diversity [Domestic Fuel/Domestic Demand]	Air Quality (Sox, Nox)	Ash Production	Land requirements	GHG
	M USD	*M USD*	*%*	*MW*	*%*	*%*	*Thousand Tons*	*Thousand Tons*	*Acres*	*Thousand Tons*
Strat I - Unconstrained	1.6	0.0	6.5	7.0	10.0	5.5	8.0	0.0	0.6	4.8
Strat II - Diversify with Coal	3.4	8.8	5.9	10.0	10.0	10.0	10.0	10.0	0.0	10.0
Strat III - Diversify with Nuclear	0.0	0.1	10.0	9.1	9.9	6.9	9.2	0.0	0.3	5.7
Strat IV - Diversify Geographically	2.1	2.8	9.5	5.5	0.0	5.3	7.9	0.0	0.6	4.6
Strat V - REMP	9.2	10.0	0.0	2.8	5.4	3.5	6.4	0.2	10.0	3.4
Strat VI - Enhanced G-NDC	10.0	4.7	4.5	0.0	8.0	0.0	0.0	0.0	1.6	0.0

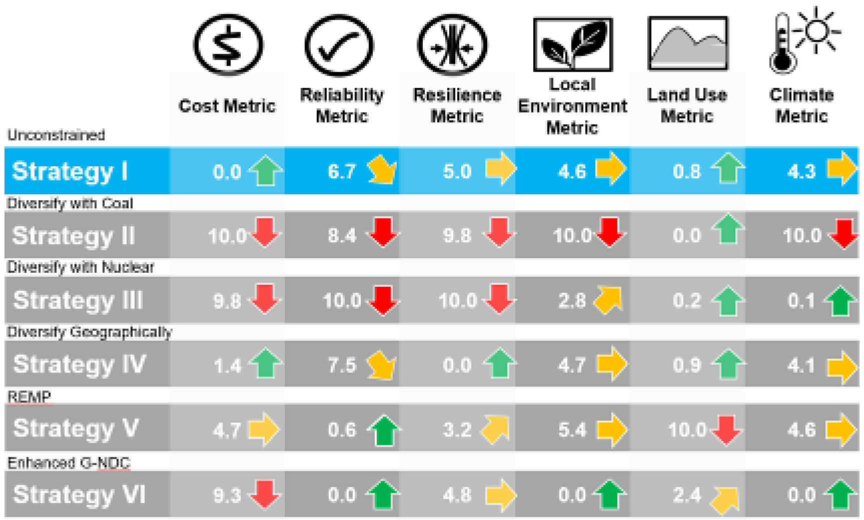
Table 46: Combined Metrics Ranking of the Strategies for the 10-Year Planning Period

	Cost Metric	Reliability Metric	Resilience Metric	Local Environment Metric	Land Use Metric	Climate Metric
Business As Usual Strategy I	0.8	6.5	7.0	4.0	0.6	4.8
Diversify with Coal Strategy II	6.3	8.0	10.0	10.0	0.0	10.0
Diversify with Nuclear Strategy III	0.0	10.0	7.9	4.6	0.3	5.7
Diversify Geographically Strategy IV	2.5	7.5	0.0	3.9	0.6	4.6
REMP Strategy V	10.0	0.0	2.5	3.3	10.0	3.4
Enhanced G-NDC Strategy VI	7.6	1.1	1.9	0.0	1.6	0.0

Table 47: Ranking of the Strategies for 19-Year Planning Horizon

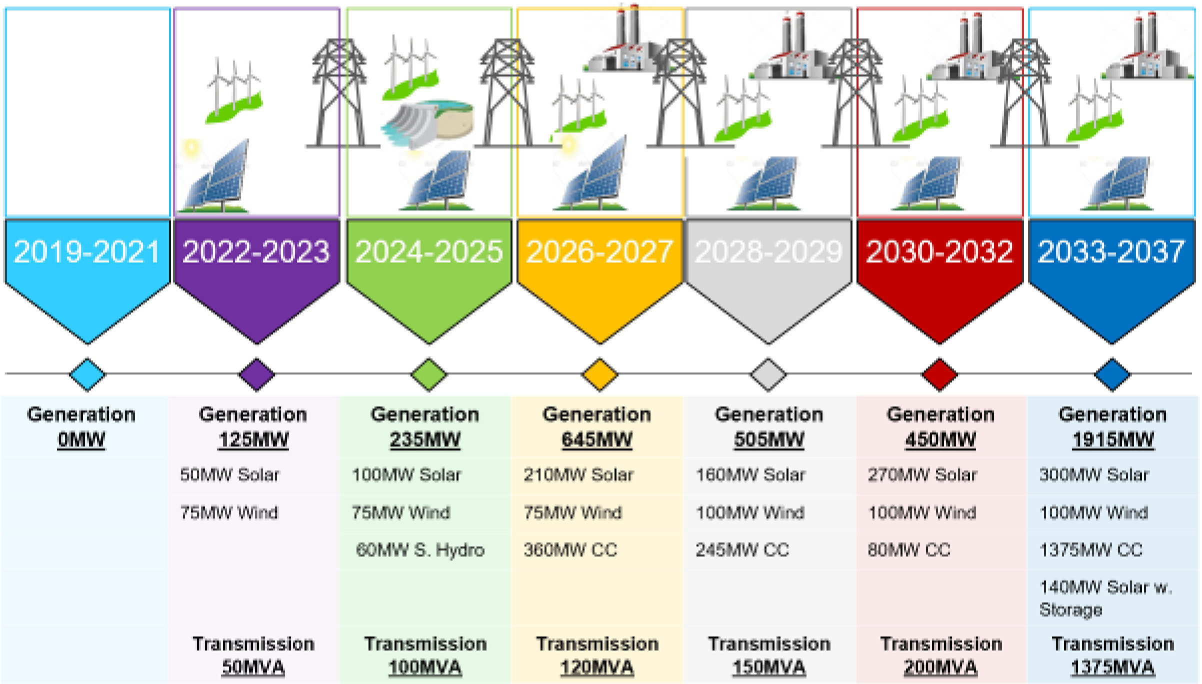
	COST METRICS		RELIABILITY METRIC		RESILIENCE METRIC		LOCAL ENVIRONMENTAL		LAND USE	CLIMATE METRIC
	Total Capital Cost	Total System Cost	Transmission Congestion	Unserved Peak	Local Reserve (Ashanti&North)	Resource type diversity [Domestic Fuel/Domestic Demand]	Air Quality (Sox, Nox)	Ash Production	Land requirements	GHG
	M USD	*M USD*	*%*	*MW*	*%*	*%*	*Thousand Tons*	*Thousand Tons*	*Acres*	*Thousand Tons*
Strat I - Unconstrained	0.0	0.0	6.3	7.0	10.0	0.2	8.7	0.0	0.8	4.3
Strat II - Diversify with Coal	6.8	10.0	6.3	10.0	10.0	9.5	8.8	10.0	0.0	10.0
Strat III - Diversify with Nuclear	9.3	7.2	10.0	9.1	10.0	10.0	5.3	0.0	0.2	0.1
Strat IV - Diversify Geographically	0.4	1.9	9.2	5.5	0.0	0.4	8.9	0.0	0.9	4.1
Strat V - REMP	2.8	5.0	0.0	2.8	6.6	0.0	10.0	0.1	10.0	4.6
Strat VI - Enhanced G-NDC	10.0	5.5	1.8	0.0	7.9	2.0	0.0	0.0	2.4	0.0

Table 48: Combined Metrics Ranking of Strategies over 19-year Planning Period



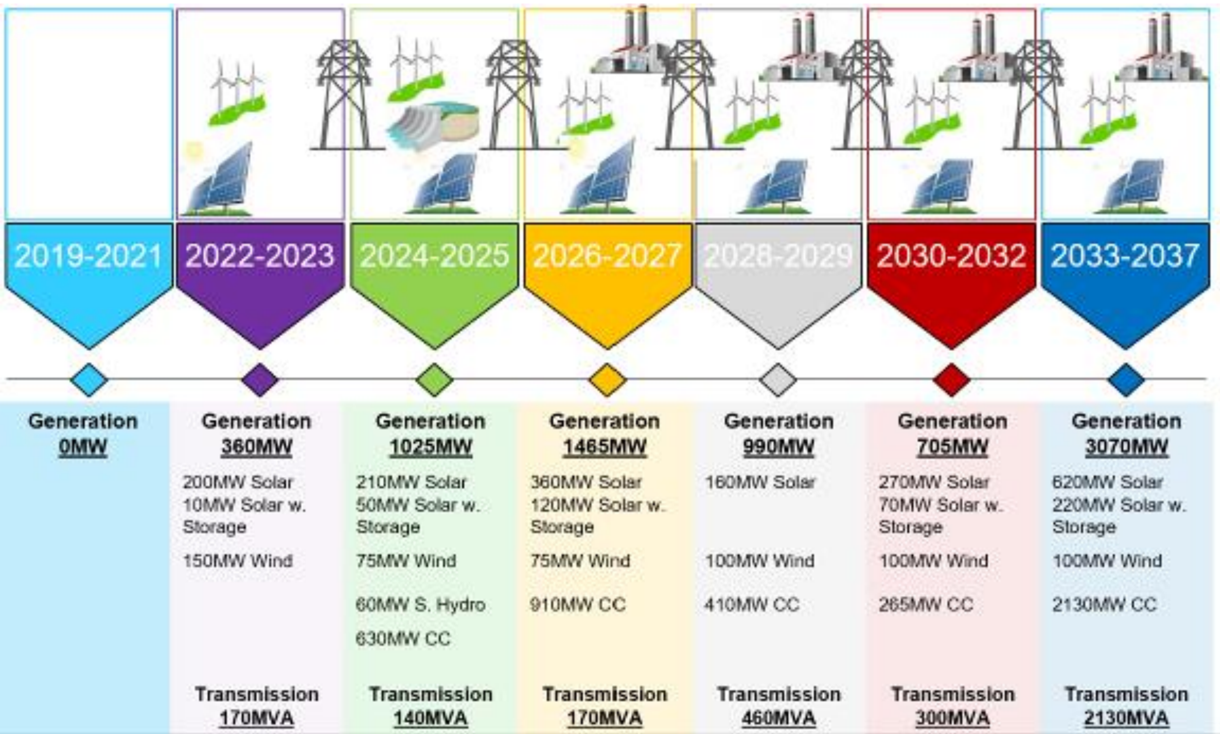
	Cost Metric	Reliability Metric	Resilience Metric	Local Environment Metric	Land Use Metric	Climate Metric
Unconstrained Strategy I	0.0	6.7	5.0	4.6	0.8	4.3
Diversify with Coal Strategy II	10.0	8.4	9.8	10.0	0.0	10.0
Diversify with Nuclear Strategy III	9.8	10.0	10.0	2.8	0.2	0.1
Diversify Geographically Strategy IV	1.4	7.5	0.0	4.7	0.9	4.1
REMP Strategy V	4.7	0.6	3.2	5.4	10.0	4.6
Enhanced G-NDC Strategy VI	9.3	0.0	4.8	0.0	2.4	0.0

Figure 73: 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 6.2.1.

Figure 74: 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 22 and Figure 23 in Section

5.3.1). The results of the Least Regrets strategy optimized under the High Demand case are shown in Figure 74.

A comparison of Figure 74 and Figure 73 shows an additional 235 MW of RE capacity is necessary in 2022-2023 under the high demand case, relative to the reference case demand. The model also expects a new gas plant of about 630 MW to be built earlier than under the reference demand scenario in the 2024. Alternatively, the retirement of AKSA would also have to be reconsidered.

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.

Therefore, in the short-to-medium term, the focus should be not to build any new conventional power plants until the mid-2020s, and if the demand growth does indeed move to the higher growth trajectory over the next 2-3 years, then the next update of the IPSMP in 2021-22 can account for these changes.

6.4.1. Gas Demand in the Least Regret Strategy

<u>Reference Electricity Demand Case</u>

With increasing electricity demand, the demand for natural gas from power plants in both the Takoradi and Tema enclaves increase gradually from 2019 through to the end of the planning period. See Figure 75.

The annual average demand for gas for power plants in Takoradi rises from 170 MMcfd in 2019 to about 240 MMcfd by 2020. By 2028, gas demand reaches about 280 MMcfd. Starting in 2020, more of the domestic gas from Sankofa gets transferred to the east via the West-to-East reverse gas flow to support gas demand in Tema. The gas demand in Tema enclave is expected to be about 45 MMcfd in 2020 and it rises to about 120 MMcfd by 2028. A significant portion of the gas supply in the Tema enclave comes from N-Gas. '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.

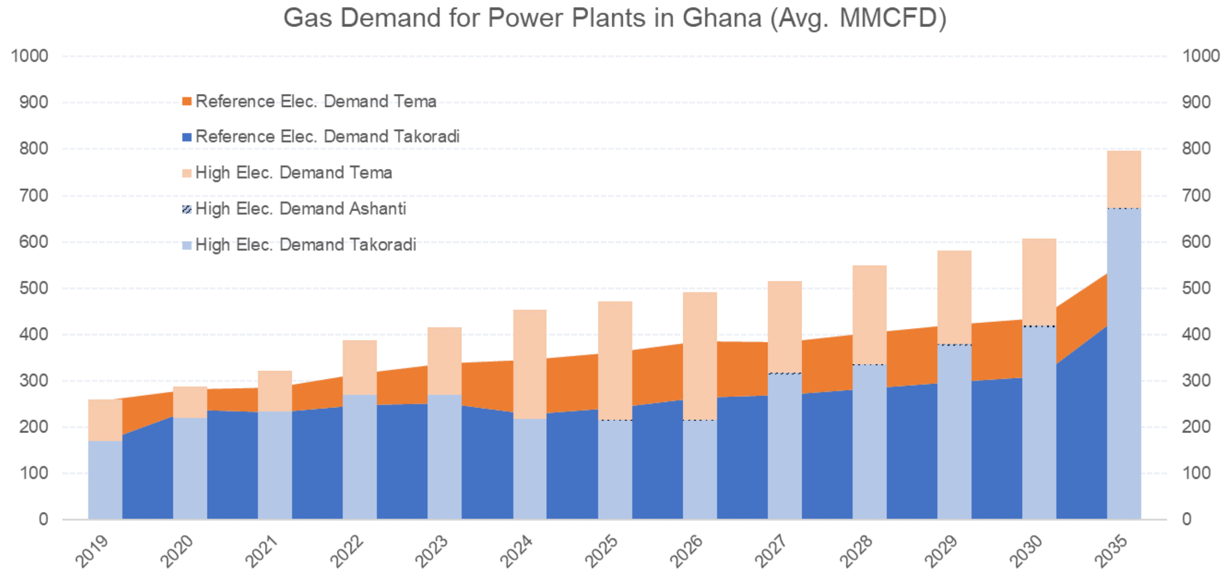
The total gas demand in Ghana continues to rise from about 280 MMcfd in 2020 to 400 MMcfd in 2028 and 560 MMcfd in 2037. This demand is met by new gas supply from domestic gas production and N-Gas under reference electricity demand.

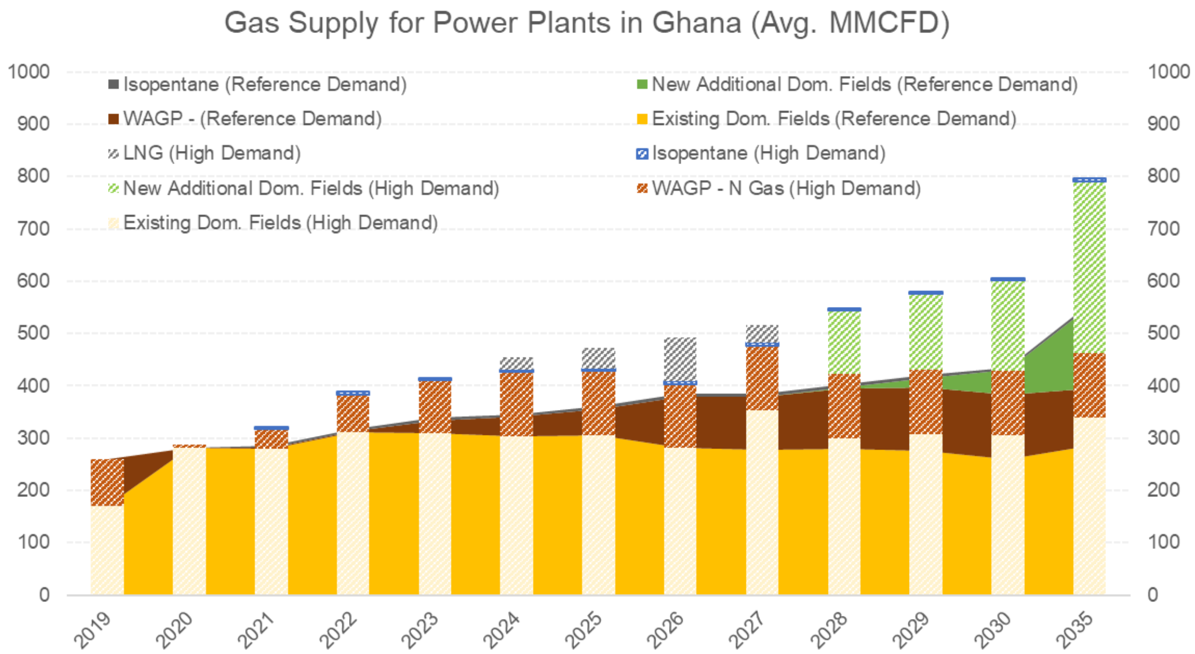
<u>High Electricity Demand Case</u>

Under a high electricity demand case, the total gas demand in Ghana rises from 290 MMcfd in 2020 to 550 MMcfd in 2028 and 800 MMcfd in 2037. If the electricity demand is very high (as discussed in Figure 22 and Figure 23 in Chapter 5.3.1), then gas demand in both Tema and Takoradi continues to rise over time. Takoradi demand is about 70% of total demand in 2028, and 80% in 2037. See Figure 75.

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 2024. This increased need for gas is indicated by the utilization of LNG in the SouthEast as early as 2024. The LNG volumes shown here in the model serves as a proxy for additional supply from WAGP or additional domestic gas.

Figure 75: Gas Demand (top) and Supply (bottom) for Least Regret Strategy under Reference and High Electricity Demand Cases





6.4.2. 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 73), 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 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 pure economic basis, especially if the capital cost of the vRE technologies are 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 in the consider how the variable RE 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 8.5cents/kWh and 9 cents/kWh.

Therefore, with all the uncertainty on the cost of natural gas supply to power plants and the price variable RE are going to be procured in the future**, it is important NOT to consider the projected RE builds shown in Figure 73 as "fixed" or "must-builds",** but rather 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.

6.4.3. 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 49 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 49: 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
Coal Power	12 – 18 months	6 – 12 months	3 - 4 years	5 – 7 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

Table 50: Timeline for concluding negotiations for projects (incl. some existing Projects with PPAs) based on the Least Regret Portfolio (next 10years)

Expected Online-Year	2022-2023	2024-2025	2026-2027	2028-2029
Solar PV	mid-2020 (50 MW)	2022 (100 MW)	2024 (210 MW)	2026 (160 MW)
Wind	Late-2019 (75 MW)	2021 (75 MW)	2023 (75 MW)	2025 (100 MW)
Small Hydro		2021*(60 MW)		
Combined Cycle Plant			2020	2022
Transmission	2018	2020	2022	2024

* Note that for Small Hydro, VRA has initiated the development process for the Pwalugu 60 MW small hydro power plant in 2019, and the plant is expected to come online by 2025. We anticipate that there is no need for a financial closure process in this case. So, the decision to build has to be made by 2021, so that the construction can start to get the plant online by 2025.

Currently, in Ghana, there are already several different PPAs that are under discussions for new power plants (combined cycle, solar, wind, and biomass) with ECG. For these projects that are already under negotiations with ECG, then only need to need to finalize their PPAs and any other requirements to start the financial closure process. Given this situation, Table 50 shows the latest year by which the procurement negotiations (PPA, PCOA, etc.) has to conclude, so that these projects that are already under negotiations with ECG can start their financial closure process. We are assuming that a competitive bidding process for new projects will only start for projects that will come online in the 2030s. If any of the new projects are competitively bid, then the bids have to start 6 – 18 months earlier than what is shown in Table 50.

7. KEY FINDINGS AND RECOMMENDATIONS

7.1. KEY FINDINGS

The modelling of Ghana's power sector, for which the Integrated Planning Model (IPM®) was used, produced a number of key findings. A selection of these findings and associated implications are described below.

7.1.1. Generation and Demand

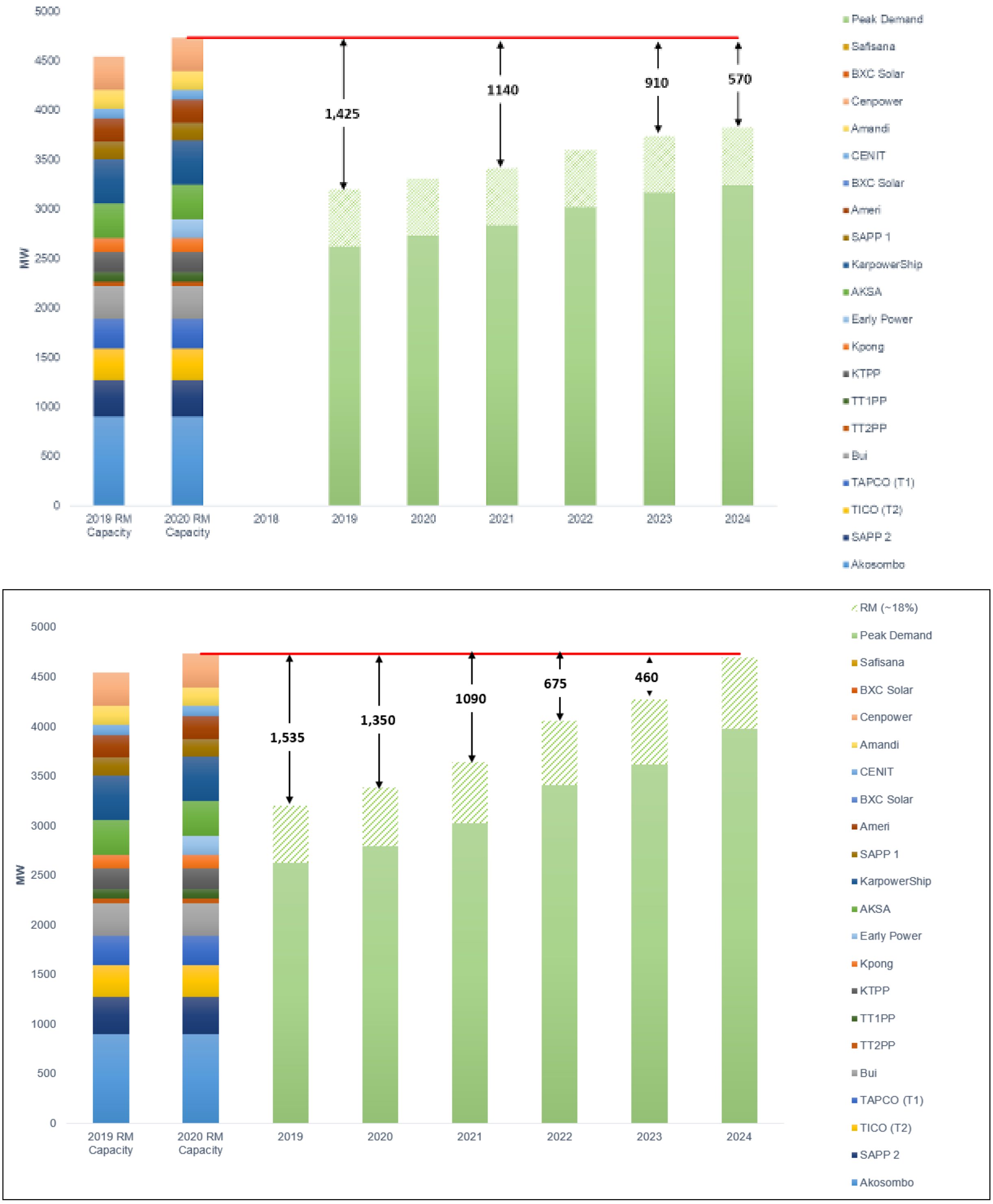
1. The modelling results confirm that there is significant overcapacity in Ghana, at present, and that this overcapacity is expected to continue for the next 5–7 years as the power plants currently under construction (see Table 20 in Section 5.4.1) are commissioned in 2018 and 2019. The net dependable capacity, as of December 2018, was 4472 MW,[46] but the projected high case peak demand in 2019 is expected to be 2797 MW.[47] Therefore, the reserve margin in 2018 and 2019 are significantly higher than the planned reserve margin of 20%.[48] Furthermore, the overcapacity challenge situation is expected to continue into the mid-2020s. See Figure 76.
2. Additional conventional, thermal generation will not be needed until the mid-2020s in Ghana, due to the gas-fired plants (Early Power – 377.5 MW, Amandi – 190 MW and Marinus – 28.8 MW) that are already under construction and Cenpower – 340 MW, which was commissioned in August 2019. These plants will add a combined net dependable capacity of 936 MW when they are all fully commissioned by the end of 2020.
3. Fixed capacity charges for existing and under-construction plants are under negotiations by GoG with generators to minimize the impact of electricity tariffs on consumers.
4. Unconstrained Strategy, which utilizes mainly indigenous resources (i.e., small hydropower, renewables, and indigenous natural gas) which has no technology specific constraints is the ***Least-Regrets*** Strategy, primarily because it is the least-cost option over the entire planning period and it allows for greater energy security. In this strategy, solar photovoltaics (PV) and wind power plants are integrated into the grid gradually over time, and additional combined cycle capacity will need to be built beyond the 2020s.

[46] Energy Statistics. 2018. Draft. Page 6, Table 3.1 (compiled by Energy Commission).

[47] The 2018 Supply Plan for Ghana expects peak demand in 2018 to 2523 MW, in line with the IPSMP projections.

[48] The 2018 Supply Plan for Ghana assumes a planned 25% reserve margin for all of Ghana throughout the medium-term period, but does not justify the reasoning behind the assumption.

Figure 76: Medium-Term Supply-Demand Balance for Reference Electricity Demand (top) and High Case Electricity Demand (bottom) in MW



5. Over the next 10 years (2019–2028), based on the updated 2019 Least-Regrets Strategy under the Reference Case demand projection, a total of about 750 MW of renewable energy (solar PV, wind, biomass, and small hydropower) and combined cycle capacity of about 460 MW will be needed in 2027.

   - The builds for renewables and conventional thermal plants for the next 10 years and the following 10 years for the 2019 Least-Regrets strategy are shown in Table 51.

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 51: Unplanned Builds in MW for Least-Regrets Strategy

Unplanned Builds (MW)	Reference Demand Case	
	2019 Least-Regrets	
	2019–2028	2029–2037
Renewable	745	1,070
Conventional Thermal	465	1,595
Unplanned Builds (MW)	High Demand Case	
	2019 Least-Regrets	
	2019–2028	2029–2037
Renewable	1,410	1,540
Conventional Thermal	1,665	2,670

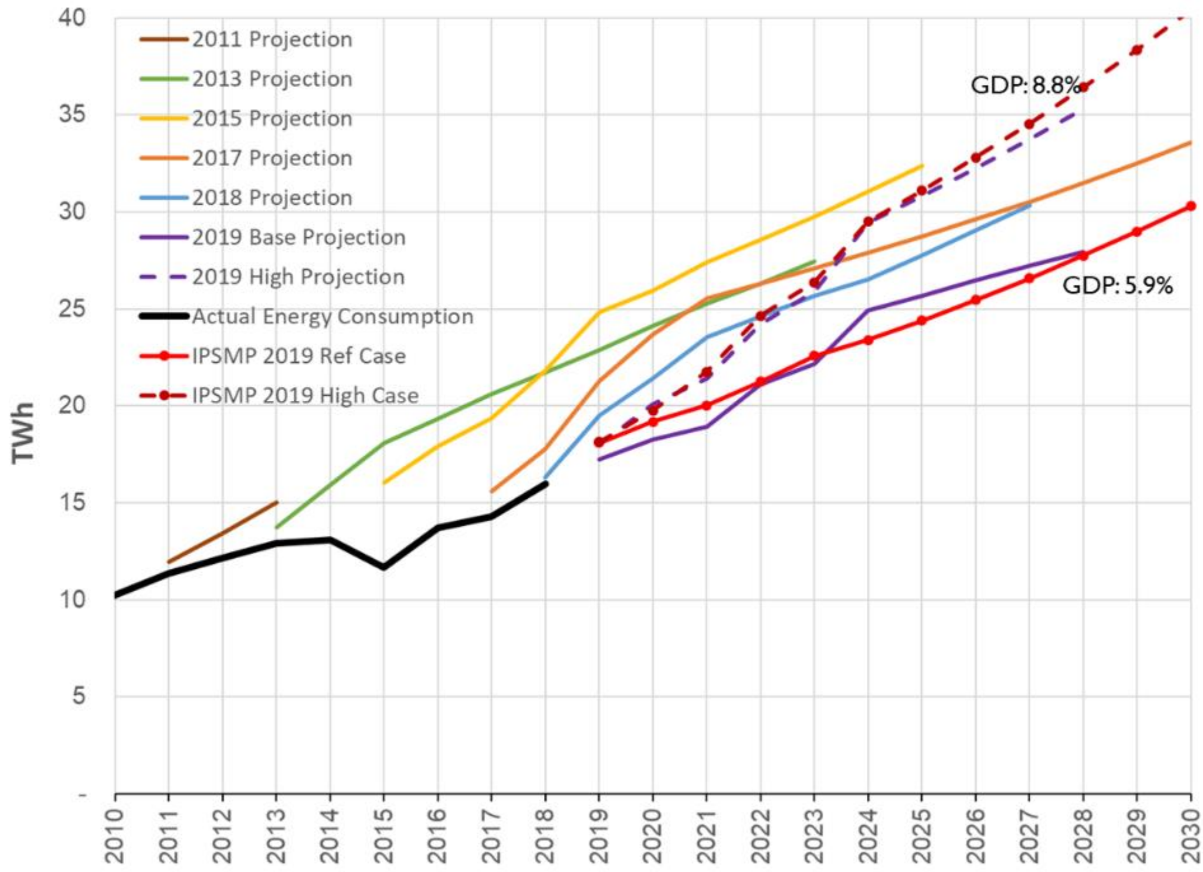
6. Demand growth is the major factor that determines how much new capacity is needed in the future. Therefore, a focused effort to better understand what the underlying factors are that determine demand growth (e.g., temperature-dependency, price-elasticity, granularity of sectoral and regional economic 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.

   Figure 77 shows the demand projections from the Annual Supply Plans developed by GRIDCO and EC from 2010 onwards, relative to the actual demand. The IPSMP reference case and high case demand forecasts are also added. As is clear, the demand growth expectations in recent years (2018 and 2017) are significantly lower than what the Supply Plan Committee estimated in the past. In the 2019 Supply Plan, two forecasts were developed—one for a base case and another for the high case. Both of these are shown in comparison with the IPSMP 2019 forecasts. The primary difference between the recent Supply Plan forecasts and IPSMP is the expectation of demand from VALCo and exports.

   Ghana's energy intensity (kWh per unit of GDP), as with countries worldwide, has been declining over time as the country becomes richer and transitions to a service industry-oriented economy.

Figure 77: Comparison of Annual Supply Plan forecasts over time, with IPSMP Forecast



Source: Various Ghana Annual Supply Plan (from GRIDCo)

7.1.2. Renewable Energy

7. The modelling results indicate that solar PV and wind capacity (as well as biomass, waste-to-energy, small hydropower, etc.) need to be developed starting in 2023, even without any renewable energy target. However, if the government were to impose a 10% penetration of renewable energy in the generation mix by 2030, then additional plants would need to be built sooner.

8. Setting renewable energy (RE) targets as well as fixing feed-in-tariffs (FITs) are helpful in introducing, attracting, and promoting renewable energy penetration in the country. However, by the mid-2020s (or even earlier), solar PV and wind generation costs are expected to decline significantly over time. If this declining trend continues, these renewable energy power plants can be built purely on an economic basis, without any subsidies. This is particularly the case, if Ghana were to competitive procure the RE plants.

9. 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 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

10. Despite the current over-capacity in the short-term, developing and installing competitively procured 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. Slow and gradual buildup of new solar PV and wind capacity is needed for local experts to gain operational know-how on integrating variable renewable energy plants into the grid.

    - As appropriate, solar PVs with storage can be sited in the middle-to-northern belt of the country (NEDCo region) to contribute towards meeting peak demand by mid-2020s.
    - Locating generation resources around the northern part of Ghana (due to the relatively higher insolation in that area) will address the challenge of inadequate local reserve margin. New generation in this area will also reduce transmission losses and address the current voltage stability issues around Kumasi.

11. 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.

12. 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 and one small one in the Southwest region. Small hydropower plants such as the proposed Pwalugu Multi-purpose dam have additional benefits such as irrigation and flood control.

13. 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.

7.1.3. Conventional Power Plants

14. 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 51 is based on natural gas, then additional coal or nuclear plants should not be built. Similarly, if significant nuclear capacity is firmly planned to be built by the early 2030s, then gas and coal 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.

- Building a coal power plant in Ghana would be most relevant when domestic gas is scarce or if there are sustained high domestic gas or LNG prices.
- 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. For example, coal power plants will not be built even in the Unconstrained Strategy if the average delivered gas prices are less than $8-9/MMBtu in the long run.
- Nuclear plants are generally more expensive to build than coal or gas 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. However, nuclear becomes attractive under high gas price or limited gas supply scenarios.

7.1.4. Transmission

15. 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.
    - Expanding transmission capacity lowers overall system cost, and allows for greater export opportunities to Burkina Faso and Mali.

7.1.5. Fuel Supply

16. The Tema – Takoradi Interconnection project (TTIP) or reserve flow has been implemented in August 2019 to move stranded gas in west to electricity generation stations in the Tema enclave. This has improved the flexibility in electricity supply significantly in the country.
17. The implementation of the TTIP coupled with the relocation of the Karpowership to the Western Region has provided an opportunity to drastically reduce the financial obligations under the Sankofa take-or-pay agreement. Without the reverse flow arrangement, gas power plants in the east (Tema power enclave) will not be able to run fully for because of inadequate gas availability while plants in the west will be under a lot of pressure to maintain high operational availability to utilize the Sankofa gas.
    - New gas production estimates indicate that there is sufficient gas supply from Sankofa, TEN, and Jubilee to meet gas demand for power generation beyond 2023.
    - Additional domestic gas is expected to come in in 2028 and as such the requirement for the procurement of LNG will be further delayed unless there is high growth in electricity demand.
    - 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.
    - A LNG regasification and storage terminal might still be relevant to increase gas supply security, in case 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. Enhance and institutionalise the current process of undertaking the current annual supply-demand forecasting.
   – The annual supply-demand forecasting currently led by the Energy Commission (EC) and GRIDCo would benefit from the use of better modelling tools and collection of more granular data from the distribution companies (DISCos) and bulk customers, using standard data collection templates. Strong collaboration among the various planning institutions is necessary, particularly in the development of various data collection templates and survey instruments and execution of data collection for the demand analysis. Maintaining an "error-list" to assess how well the forecast has performed against the actual consumption will also help to reduce errors in future demand forecasts.
2. Support and implement policies and programmes that support the deployment of energy efficiency measures.
   – Energy audits carried out since the 1980s indicate 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.
   – Analysis by the IRRP Project shows that nearly 30% of electricity consumption in commercial buildings can be saved through cost-effective improvements in lighting and cooling. Energy audits carried out at Ghana Water Company water treatment plants at Weija and Kpong in September 2019 also indicate the potential for large savings in energy use can be achieve by implementing simple energy efficient measures.
   – Furthermore, substandard or non-energy-efficient appliances should not be permitted to enter the country at the points of entry, through a strong collaboration between GRA/Customs, the EC, and Ghana Standards Authority in effectively enforcing this control.
3. The Public Utilities Regulatory Commission (PURC) and the EC should facilitate and support distribution utilities to implement energy efficiency programmes that are revenue neutral.
4. The EC should expedite action and expand the scope of energy efficiency labelling programme to include more electrical appliances.

7.2.2. Transmission

5. 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 the need for an updated version of the Transmission System Master Plan.
6. 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.
7. 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.
8. 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.
9. With the construction of the 330 kV/34.5 kV Pokuase substation in progress, there is the 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.
10. 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.
11. 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.

7.2.3. Distribution Planning

12. Utilise information gathered from smart meters and automatic meter readers (AMR) to implement options to reduce commercial losses and improve the collection rate of the distribution companies. Analyses of the data will also provide the most recent data from these customers for future demand forecasting.
13. There is the need for improved co-ordination 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.
14. Improve inventory management of meters to avoid the situation where some customers are put on flat rates.
15. 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 the 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.
16. 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.
17. NEDCo needs to expand the scope of load flow analyses carried out in Tamale (2016) to include heavy load centres like Sunyani, Techiman, Wa, and Bolgatanga and other towns and cities to improve distribution planning.
18. 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)).
19. 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 from 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.

20. 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.
21. Distribution utilities should coordinate with MoE and 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

22. EPA in conjunction with EC should consider including the installation of low NO_x burners to limit emissions in the specifications for all new thermal power plants (both gas and coal fired).

Regulation and Tariffs

23. Regulating agencies should be equipped with state-of the art methodologies, tools and equipment to undertake and deliver their mandate for the health of the sector.

Rates/Ratemaking

24. In order to address public concern and acceptability of published tariffs, PURC need to provide more information and engage the public in the rate setting of the various components of the tariff (bulk generation tariff, transmission service charge (TSC), and distribution service charge (DSC), as well the ancillary service charge).
    - The quarterly adjustments and major reviews should be participatory and regular to engender confidence and avoid big jumps in the rates. This will also help businesses to plan their finances and other business activities in a more predictable manner.

Financing

25. 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.

Government Coordination for Infrastructure Development

26. NDPC can utilise the results of the IPSMP as a framework to review and update the power component of its Energy Infrastructure Plan.
    - The National Development Planning Commission (NDPC) is responsible for the development of a holistic national development plan, which is the National Infrastructure Plan (NIP) that covers energy, water, transport, housing, etc. In the case of the energy sector, the NDPC is working closely with EC, VRA, GRIDCo, NEDCo and ECG to develop the Energy Infrastructure Plan (2018–2047), which is expected to cover all the fields of energy (e.g., power, petroleum, nuclear, renewable energy).

RECOMMENDED FRAMEWORK FOR POWER SECTOR PLANNING

Planning needs to be more collaborative among the key players in the power sector—e.g., MoEn, EC, VRA, BPA, GRIDCo, ECG, NEDCo, and GNPC—rather than how it has been conducted in the past when the "silo" approach was sometimes used for most planning (i.e., different entities within the same sector planned separately with different sets of assumptions, data sets, planning horizons, and technical analysis).

In contrast, the more recent collaborative approaches have been viewed more favourably by the sector agencies—for example in the development of the Annual Supply – Demand Plan (involving EC, GRIDCo, VRA, BPA, ECG and NEDCo) and the development of this Integrated Power Sector Master Plan (IPSMP), with support from the IRRP Project team. In the development of the IPSMP, a Technical Committee, made up of representatives from the relevant sector institutions, was put together to (i) ensure there is consensus on the input assumptions for the modelling (e.g., demand and supply assumptions); (ii) review basis for the various technical analyses (i.e., base case, scenarios/sensitivities) to be conducted for the planning; (iii) deliberate on the model outputs; and (iv) produce a common study report.

Furthermore, a Steering Committee was also convened to (i) review the IPSMP results, and (ii) provide overall guidance to the project. This committee-based approach proved to be critical in building a collaborative environment for discussions and understanding of various planning issues and also engendered ownership of the modelling inputs, results and the IPSMP study report.

Similarly, for the 2019 Update, various meetings were convened to review the Input Assumptions, the Strategies, Scenarios, and sensitivities. The continuation of this collaboration in future power sector planning activities (i.e., reviews/updates of the Annual Supply-Demand Plan, the IPSMP, and the Strategic National Energy Plan [SNEP]) is critical and essential for the implementation of these plans and the holistic development of the power sector of the country so that all the sector stakeholders can participate in these reviews and updates, as well as take full ownership of the plans.

Table 52: Recommended Membership of Power Planning Technical Committee

Core Group	Co-Opted Members
Energy Commission (Co-Chair)	PURC
GRIDCo (Co-Chair)	MoEn, MoF
VRA, BPA (Hydro)	EPC
ECG, NEDCo	EPA, MESTI,
	GNPC, GNGC, NPI
	GSS

27. It is recommended that a core group of technical staff that currently undertakes the annual supply-demand planning process should continue as a standing committee and be renamed as the **Power Planning Technical Committee (PPTC).**

This standing PPTC should be **jointly chaired** by EC and GRIDCo. See Table 52. In line with its statutory mandate, the EC would be responsible for the review and update of the longer-term SNEP and IPSMP while GRIDCo (as the System Operator) would be responsible for the development of the Annual Supply – Demand Plans within the context of the PPTC. The funding of the activities involved in the SNEP and IPSMP update processes should be assumed by EC, and that of the Annual Supply – Demand Plans by GRIDCo.

The proposed mandate of the PPTC could include the following:

i. Provide the data, information, and inputs into planning model(s);
ii. Share models and/or their methodologies;
iii. Provide analytics and technical support;
iv. Engage in model development (assumptions) and review modelling results;
v. Formulate, review, and deliberate on the outputs, recommendations, and their implications;
vi. Engage in discussions to create a consensus in various outcomes;
vii. Develop updates of both the Annual Supply – Demand Plan and IPSMP three times in a year by reviewing all the modelling inputs;
viii. Identify technical specialists in other agencies who should participate as "co-opted" members; and
ix. Provide guidance on technical needs in their respective agencies for long-term planning.

28. It is also recommended that PPTC reviews the modelling inputs three times in a year for updating both the Annual Supply – Demand Plan and the IPSMP. This review of modelling inputs will help in both the planning and the procurement process, and with the IRRP process and modelling improvements.

This **PPTC** core group can co-opt other agencies and members in order to provide data nad information to the planning activities. See Table 52. As part of its mandate, PPTC will need to consult a number of stakeholders, including NDPC, bulk customers, Ghana Chamber of Mines, Association of Ghana Industries, academia and other relevant tertiary institutions (technical universities, polytechnics, research institutions, etc.), and Civil Society Organisations (environmental groups, consumer advocacy groups, etc.). Academics and other staff from relevant tertiary institutions (technical universities, polytechnics, research institutions, think tanks, etc.) can assist in the data collection and in the capacity building of participating agencies. As noted earlier, personnel from other institutions can be brought into the PPTC, as and when necessary.

The MoEn should continue to provide sector policy direction for the planning activity of the energy sector and provide more focused supervisory oversight for the EC, to ensure that the Commission is playing its role in the IPSMP recommendations. The EC should regularly and closely monitor and take actions (as necessary) to ensure that the scheduled for the Annual Supply – Demand Plan and the longer-term IPSMP plans are adhered to. The EC should also ensure there is progress in the timely execution of the study recommendations and scheduled update of plans. All future IPSMP updates should use the jointly developed assumptions, inputs, and the same or similar tools (as is feasible) to ensure continuity of power sector planning.

The IPSMP process will improve at the national level if the various stakeholders involved in all of the planning process stages become more collaborative in:

a. Comprehensive data collection and screening;

b. Discussion of achieving consensus on the assumptions; and

c. Alignment of the planning objectives to the energy sector vision.

29. Standard templates need to be adopted for data collection and screening for all data collected from distribution companies (DISCos) and generating companies (GENCos), bulk customers, and other end users. All entities or data providers should be encouraged to regularly supply all relevant data needed for PPTC activities.

Below is a proposed monthly timeline for the PPTC activities focused on the development of the Annual Supply – Demand Plan.

Table 53: Illustrative Timeline for PPTC Activities on an Annual Basis

January	Finalize and release current year Annual Demand-Supply Plan (on EC and GRIDCo website)
February	Plan for special studies, sub-committee meetings, model review, and data collection surveys
March - April	Review actuals for previous year and Q1 data; **Update IPM model inputs**, and make any adjustments for current plan, as needed; Provide final inputs to EC's Energy Statistics for previous year
April - September	Data collection, Surveys, & Screening; Load forecasting (DISCOs, BSC, Exports); **Update IPM model inputs (July/August)**; Undertake other modeling reviews and special studies, and evaluate implications
October	Update on Thermal Gen plants and Transmission Network
November	Update hydrology data & status/contribution of hydropower plants
November/December	Re-run models with updated data (demand and supply)
December	**Update IPM model inputs**, assess implications of any changes; Develop updated "Annual Demand-Supply Plan"
January (Next Year)	Finalize and release Annual Demand-Supply Plan (on EC and GRIDCo website)

7.4. Institutional Roles in the Future Planning Process

This section highlights the new roles expected of the various institutions in the future planning process. Going forward from 2019, the various institutions in the energy sector are expected to follow an integrated and collaborative approach in undertaking energy planning activities. This will require a shift in the traditional planning roles that the various sector institutions play currently.

7.4.1. Role of Ministry of Energy

The MoEn should continue to play its policy-making role in the energy sector, with more focused supervisory monitoring of the power sector master planning process (including ensuring that policy objectives and targets are given due consideration) and associated outcomes (e.g., implementation of Master Plan recommendations).

The MoEn is therefore expected to enhance its supervisory role in monitoring the performance of the mandated sector institutions to (i) adhere to policy directives, (ii) ensure close adherence to the planning calendar, and (iii) ensure progress of the implementation of planning study recommendations. Such enhanced supervision of the planning process should help avoid power supply crisis situations that could call for the procurement of emergency power plants.

Hence, any observed slipping in the planning timelines for (i) reviewing and updating the Annual Supply – Demand Plan as well as the IPSMP and (ii) the implementation of planning study recommendations by sector institutions should be brought to the attention of the EC and the PPTC in a timely manner, so that they can undertake the necessary remedial actions to close the gaps.

7.4.2. Role of Energy Commission

The EC, as the sector agency mandated with planning for the energy sector, should play the lead role in the periodic update of the IPSMP and the SNEP in close cooperation with other sector agencies like GRIDCo. EC's mandates include, inter-alia, (i) preparing and developing the indicative national plans, and (ii) monitoring and reviewing the implementation of expansion plans. In this regard, the EC should strengthen the capacity of its Planning Division by reviewing its capacity status and requirements and the possible recruitment of additional staff to enable the EC fulfil its mandates.

The EC and GRIDCo, as joint chairs of the Power Planning Technical Committee (PPTC), should therefore liaise closely to facilitate:

i. Broader stakeholder consultation process within the sector per the planning calendar;
ii. The provision of data from all generating and distribution companies, bulk customers, and other end users using standard templates for data collection for use by the PPTC for review and update of the models;
iii. The activities of the PPTC to ensure consensus on model inputs, outputs, and study results is achieved;
iv. The timely preparation and review of Annual Supply – Demand Plans, and updates of the IPSMP; and
v. The implementation of the recommendations of the Annual Supply – Demand Plans and the IPSMP.

A key role of EC, through its leadership in the PPTC, is to periodically review demand forecasts for the sector. The results of this periodic review of the demand forecasts vis-à-vis the anticipated capacity additions will enable the EC to raise "red flags" in a timely manner to indicate situations of generation deficits or overcapacity in order to trigger timely remedial actions for adequate capacity procurements. In any potential situation of overcapacity (potentially as a result of a lower demand growth rate or policy decisions made outside the recommendations of the IPSMP), the EC must notify the MoEn of the possible future overcapacity, its extent, and the implications to the sector. For example, overcapacity could lead to higher electricity costs due to the payment of capacity charges for plants that may not be fully dispatched, as initially anticipated.

The EC will also be expected to host detailed historic data on the energy supply value chain, from fuel use through generation to transmission and distribution, as well as end-use energy consumption data. The availability of such granular data would allow for more detailed analysis of various aspects of the planning process, provide sufficient data for trend analyses, and thus generally enhance the planning activity. The EC's data collection process needs to be streamlined and the required data clearly defined and collected using standard templates and survey instruments/methodologies which should be filled by relevant stakeholders within a specified timeframe. Once this data collection process is institutionalised, it will set the stage for seamless annual reviews.

The EC should collaborate with the Ghana Statistical Service and all other energy and allied data providers in its data collection process. The EC should also ensure a strong and broad collaborative consultation with license holders for effective data collection towards energy planning, and be more transparent in the setting of its licensing fees to ensure a better collection rate.

The EC should also regularly review the policies on renewable energy penetration targets (if any) for planning, as the grid becomes more resilient and intermittency gets moderated as a result of new developments in renewable energy technologies.

7.4.3. Role of GRIDCo

GRIDCo, as the transmission System Operator, is expected to play a key role in the PPTC by jointly working with the EC as discussed above. In particular, GRIDCo will help determine optimum location, size, and timing of capacity additions, including renewable energy plants. Even though GRIDCo has an elaborate connection agreement procedure, it will need to be updated to align with the wholesale electricity market (WEM) rules being developed. The expected implementation of WEM rules based on its guiding mandates, will enable market forces (such as locational marginal pricing) to signal the siting of new plants in the future.

The grid operator is also expected to carry out studies to highlight appropriate locations on the grid and the general magnitude of renewable energy capacities that could be technically connected to the grid through impact studies of various renewable energy installations as well as incorporation of modern technologies that could mitigate the effects of the intermittency of renewable energy.

Furthermore, the preparation of the Annual Supply – Demand Plan should be more structured, as set out under the future planning process above, and modified to a rolling revision of the IPSMP through updating the supply-demand forecast and re-running the planning model to choose new Least-Regrets strategies to meet the prevailing projected electricity demand over time.

7.4.4. Role of Distribution Companies

The DISCos (i.e., ECG, NEDCo, and EPC), which serve the final customers, are best placed to carry out demand forecasting within their regions of operation to determine customers' spot loads as well as increases in the demand of their customers due to economic growth.

The DISCos must therefore make significant inputs into the development of the Annual Supply – Demand Plan and the IPSMP, through the PPTC.

In addition to the current distribution planning studies undertaken by DISCos, further efforts need to be devoted towards developing significant loss reduction strategies. Cost-benefit analysis needs to be done continuously to show how much potential return is expected to be derived from (i) network upgrades, and (ii) the use of modern SCADA and other monitoring tools to justify the funding of investments for network improvement.

7.4.5. Role of GNPC and GNGC

In the context of the power sector planning, GNPC has been designated as the aggregator for natural gas and therefore supplier of fuel. For power sector planning purposes, both GNPC and GNGC are well placed to provide well-informed forecasts of volumes of indigenous gas that will be available to fuel thermal generation plants at different model regions. This information can also guide any decision on the location, sizing, and timing of the construction of LNG facilities, based on the schedule of oil and gas developers under license.

Furthermore, GNPC and GNGC can provide the PPTC with realistic pricing of indigenous gas, which will allow electricity generators in Ghana to offer competitive prices for electricity at home and in the West African subregion.

7.4.6. Role of Volta River Authority and Independent Power Producers

The current and prospective independent power producers (IPPs), as well as the state-owned generating companies (VRA and BPA) have a crucial role to play in planning for generation capacity expansion. These GENCos will have to take the financial decision to invest or not in new generation plants to expand generation capacity to match with increasing electricity demand. Therefore, the GENCos can provide information on financial assumptions for new power generation options.

VRA and BPA, within their hydropower operations, are expected to continue undertaking their internal planning studies, especially in areas of hydrology and reservoir management, to determine the appropriate yearly energy draft rate from the hydropower dams.

GENCos, including VRA, who have power purchase agreements (PPAs) with bulk customers, should be in a position to verify and confirm the expansion and demand growth of their customers that may provide relevant inputs into the national planning process. All market players at their own discretion may conduct electricity forecasting studies to guide their own operations as well as business decisions and requirements for capacity expansion. However, GENCo capacity expansion plans must be communicated to the EC who has the national mandate for energy sector planning and for licensing new power plants.

7.4.7. Role of Public Utilities Regulatory Commission

The PURC will continue its role of determining the transmission service charge (TSC) and distribution service charge (DSC) for the regulated electricity market. Although PURC will also be setting the bulk generation tariff (BGT) in the short term, the BGT will be replaced with the short run marginal cost when the WEM is fully established. The marginal costs will be computed by the System Operator, based on bids in the WEM.

In its rate-setting process, the PURC must adopt a rate-setting methodology that is easily comprehensible to enhance transparency. Furthermore, PURC must as much as possible demonstrate independence from executive influence.

PURC's tariffs will be a key factor in future demand forecasts, as electricity tariffs will help drive or depress demand growth. PURC should work closely with the EC, as regulators of the electricity sector, to ensure that planning activities are conducted in a timely manner, and that only power plants that conform to the expansion plan are procured through competitive bidding processes.

8. Recommended Framework for Future Procurement

In this chapter discusses how the potential investments for additional generation capacity requirements obtained from the Least-Regrets plan must be procured to ensure cost efficiency. Cost efficiency is best achieved through a procurement process based on competitive bidding. However, since the procurement process is likely to involve multiple players, a well-structured procedure needs to be put in place to guide the various participants.

Delays in the implementation of previous planning recommendations and non-adherence to prescribed procurement processes, combined with the fact that some installed power plants were procured through unsolicited and unplanned proposals from project developers, have resulted in excess generation capacity[49] and higher electricity prices.[50]

8.1. Recommended Procurement Plan

30. Future procurements of additional generation capacity to meet increasing demand should be based on the most recently updated IPSMP, and its associated analyses. The location of the additional new generation capacity, timing, size, and the type of technology or resource should all be defined or specified in such a way that the capacity procured adequately meets demand without creating an overcapacity supply situation. This supply-demand balance will then form the basis for the competitive procurement process for the additional generation capacity.

Procurement processes will be different for the regulated market and the deregulated electricity market in Ghana. The recommended approach below will also likely change when the wholesale electricity market (WEM) is fully operational.

8.1.1. Regulated Market

31. Any regulated distribution utility (e.g., ECG and NEDCo) that wishes to procure power through the Nationally Interconnected Transmission System (NITS) must first obtain a "procurement approval" or "no objection" from the PURC and EC before proceeding with the procurement process for new generation.

The EC and PURC would review whether the procurement request is in line with the IPSMP and the Annual Supply – Demand Plan, and then provide its approval to the utility to proceed with the procurement through a competitive bidding process. The EC could also direct the regulated entities to procure power generation, in case the utilities are not applying for the procurement approval to address potential or anticipated power supply shortfalls. This option allows the EC to prevent a potential situation of under-capacity (and possible emergency procurements).

32. It is recommended that the future procurement process for new power plants that are connected to the grid should be carried out based on the EC's "Framework for the Procurement of Electric Power Generation from Wholesale Suppliers of Electricity" (June

[49] Current installed generation capacity is about twice the country's peak demand.

[50] Due to payment of capacity charges for the excess generation capacity that will not be used immediately.

2010). The EC, however, will need to review and update this June 2010 edition of the procurement framework to ensure that only those new generation capacity additions that are aligned with the IPSMP and the Annual Supply – Demand Plan recommendations are procured.

33. One way for ensuring such alignment is to use the EC's licensing regime/mechanism to only license the capacity additions that are called for in the IPSMP and Annual Demand-Supply Plans. This will ensure coordinated planning and timely implementation of recommendations to prevent generation deficit or overcapacity.

Section 3.3 of the June 2010 EC procurement framework outlines the Solicitation and Selection Procedures for generation addition in a competitive manner, ranging from expression of interest to request for proposals, and through to the award stage. It also stipulates which entities can procure additional generation and how this should be done.

In summary, the procurement of additional generation capacity in the regulated market should follow these steps:

a. The procurement process is initiated by a regulated off-taker informing the EC and PURC, and requesting a "no objection" from them. In essence, the off-taker seeks "no objection" from the regulators, EC and PURC, to proceed with proposed competitive bidding including specification of capacity (size), specific location, technology type, timing, etc.
    - The off-taker understands the need to develop new capacity to meet future demand in response to the IPSMP and Annual Supply – Demand Plans.
    - In case the off-taker is not proceeding with a procurement, the EC can also consider how best to direct them to initiate the procurement process (based on triggers from consideration of procurement/financing/construction times).

b. The EC and PURC will review and approve applications/requests from DISCos to procure generation capacity, based on the updated procurement framework and planning recommendations.
    - GRIDCo can support this review by undertaking a general grid impact analysis for the potential plant to assess the impact of the new generation capacity addition on the NITS and approve the grid connection at the zonal level as being viable/acceptable or not. GRIDCo may make other recommendations for potential options for grid interconnections as well.

c. Once the "no objection" is obtained, the off-taker can then proceed with the competitive procurement steps, subject to meeting conditions for an acceptable process as defined by the regulators.
    - PURC could set maximum/ceiling prices or feed-in-tariffs for procurement of different renewable energy technologies.
    - Fuel supply agreements (FSAs) and procurement of fuel could be left to the developers, and be submitted as part of their bids (i.e., the off-taker may not want to take a fuel procurement risk); or the FSAs can be independent of the bids, and can be arranged separately.

d. The winning bidder signs the contract (a power purchase agreement [PPA]) with the off-takers to construct and supply the new generation capacity. The winning bidder also signs a connection agreement with GRIDCo (or the DISCo in the case of embedded generation).

8.1.2. Deregulated Market

Bulk and direct customers, who are in the deregulated market, may procure power generation on their own.

34. Bulk customers planning to procure new supplies to meet their demand should provide information on their demand forecast and planned supply sources to the EC and PURC, to support the work of the PPTC in developing the IPSMP and Annual Supply – Demand Plans.

GRIDCo will also provide any information it obtains (from its sources and participants on the NITS) on anticipated expansions in the supplies for the deregulated market to the EC, PURC, and the PPTC to support planning activities.

Procurement of new supplies can proceed according a bulk customer's own internal process, but the outcome of the procurement should be communicated to the EC and PURC. Following the procurement, the negotiated PPA will be signed directly between the bulk customer and the selected generation company.

The EC regulates the licensing and construction process (location, timing, capacity size, technology, and fuel) for the deregulated market through its licensing regime. In this respect, based on information from the PPTC, the EC can use its licensing mechanism to review and approve the applications/requests for new capacity additions from bulk customers.

When the WEM is fully operational, bulk customers could just purchase electricity from the WEM directly, rather than procuring power on their own.

8.2. Institutional Roles in Procurement for Additional Capacity

8.2.1. Ministry of Energy

The MoEn does **not** have a direct role in the procurement process for a new generation capacity but it should, however, monitor and ensure timeliness of procurement of any required additional new capacity.

The Ministry should request from the EC regular updates on generation capacity situation and capacity expansion schedules, as well as implementation status to facilitate close monitoring and appropriate follow-up actions. The PPTC (which is co-chaired by the EC and GRIDCo) should regularly update the expansion plan to ensure that procurement of new generation is aligned to an updated expansion plan. This updated information must be communicated to the MoEn and NDPC for incorporation of power plants that will likely be procured in national plans.

The Ministry would also ensure that funds and support are budgeted for in advance for power infrastructure investments. Where appropriate, the MoEn should facilitate credit-enhancement arrangements from the Ministry of Finance for investors.

8.2.2. Energy Commission

The EC will review and update the 2010 procurement framework to support the off-takers with their procurement process. The EC will also use its licensing mechanism to regulate capacity additions and ensure that the procurement of capacity additions is in line with the IPSMP and the Annual Supply – Demand Plan recommendations. For the regulated market, the EC will review and approve requests from DISCos to procure capacity, in line with the updated procurement framework; for the deregulated market, the EC will use its licensing mechanism to review and approve the capacity additions.

The EC will monitor the procurement and construction activities of new generation capacity additions and report any concerns to the MoEn. The EC should raise "red flags" in cases where generation deficits are foreseen and initiate timely action for a procurement process to ensure adequate capacity comes online to avoid supply crisis. In the case of capacity deficits due to delays in project implementation, the PPTC planning tools should be used to model the implications and determine the remedial measures required to address the capacity deficits. In situations of overcapacity, the EC must use its licensing mandate and process to ensure that no additional capacity is added until the demand balances with the supply.

8.2.3. GRIDCo

GRIDCo should support the EC and PURC in their review of off-taker requests for procurements by determining either general or specific locations for grid interconnection. As part of the procurement process, GRIDCo will work with the off-takers or the bidders to review the requests for proposals (in the case of off-takers) or suggest potential grid integration recommendations in the case of bidders.

GRIDCo should procure transmission expansion or re-enforcement infrastructure based on the IPSMP recommendations. New generation capacity addition and routing of new transmission lines for evacuation of power should be determined concurrently to enable investors to package both projects together for financing. Procuring generation capacity separately from that of transmission upgrades often presents challenges in correlating project delivery timing, owing to non-alignment of their financial closure.

8.2.4. DISCos

The DISCos initiate the procurement of generation capacity additions by submitting "no objection" requests to the EC and PURC. It is expected that the requests will be in line with the IPSMP recommendations.

In order to support the generation expansion, the DISCos should procure sub-transmission expansion or re-enforcement infrastructure, based on the IPSMP and Distribution Master Plan recommendations.

New bulk supply point additions and its associated distribution infrastructure for evacuation of power should be done concurrently to enable packaging of both projects together for financing. The procurement of electricity supply for distribution separately from that of sub-transmission upgrades often presents challenges in coordinating project delivery timing owing to non-alignment of their financial closure.

8.2.5. GENCos

GENCos are expected to participate in the competitive bidding process to procure generation capacity through tendering. The GENCos (i.e., VRA, BPA and IPPs) will therefore need to develop their own internal business plans to compete in the bigger future domestic and sub-regional market.

Where a bulk customer seeks additional generation capacity from VRA, BPA or an IPP through a bilateral contract, information about these contracts should be communicated to the EC for the necessary licensing arrangement and subsequent incorporation into the IPSMP through the PPTC. Similarly, to ensure appropriate evacuation arrangements, such procurements should be communicated to the suitable grid operator (GRIDCo/DISCo).

Furthermore, as the WEM develops and gains more market participants, electricity prices are expected to be more competitive and could attract further investments into the generation sector of the country.

8.2.6. Funding of Future Power Projects

GoG with the support of the World Bank has put in place an Energy Sector Recovery Plan (ESRP) to help free the accumulated debt in the sector and maintain financial sustainability in the sector. This is expected to create a healthy financial sector that would assure investors of the ability to recoup energy sector investments.

It is imperative to have a mechanism for paying back all existing debt and ring-fencing new electricity revenues for pro-rata distribution among GENCos, DISCos, and the grid operator.

8.2.7. Credit Enhancement for New Power Projects

The ongoing implementation of the ESRP and the associated power sector debt restructuring measures as well as the proposed establishment of escrow accounts to apportion payments to suppliers should help address credit risk issues.

9. Monitoring, Evaluating, and Updating the IPSMP

This chapter discusses how the Energy Commission (EC) at the behest of the Ministry of Energy will ensure that the recommendations of the IPSMP are implemented, including the suggested timeframe for the update of the IPSMP.

The monitoring and evaluation of the IPSMP implementation and the IPSMP updating process will be a collective responsibility of all power sector stakeholders, which will require collaborative efforts of all sector players—and draw particularly on the important role of the PPTC with the EC and GRIDCo as its joint chairs.

To guide this process, the IPSMP has an accompanying Monitoring and Evaluation (M&E) Action Plan that is provided in the Appendix (Volume 3). This plan provides the guidance for effective monitoring and evaluation of the IPSMP as well as for updating it. The plan assigns M&E roles and responsibilities among relevant stakeholders. It provides targets and the requirements for their review. The preferable timeframe for reviewing and updating the IPSMP is every 2 or 3 years even though the PPTC should review the modelling inputs three times in a year for updating both the Annual Supply – Demand Plan and the IPSMP. However, an update of the IPSMP is planned to be undertaken in early 2019, based on inputs from stakeholders on the modelling.

9.1. Recommended Studies for Future Updates of the IPSMP

To make the IPSMP relevant and sustainable in future years, the plan must be reviewed and updated periodically to capture prevailing developments and issues. The IPSMP can be further improved by using more accurate data obtained through improved data collection processes and also by using more granular data as they become available to allow for more comprehensive analysis. This section highlights the specific issues that need to be addressed to improve the process of updating the IPSMP in the future:

1. Improve the electricity demand forecasting.
    1.1. Collect more granular data to improve and develop a comprehensive demand forecast.
    1.2. Develop electricity demand forecast based on end-use survey data.
    1.3. Undertake spatial load forecasting to support zonal/regional planning.
    1.4. Undertake industrial/mines load forecasting.
    1.5. Collect end-use and spatial/zonal load curves.
    1.6. Consider implications of the concession agreement for ECG.
    1.7. Consider the developments in the WEM.
2. Improve assessment of Total Transfer Capabilities (TTCs).
    2.1. Continuously undertake appropriate studies to assess the level of integration of variable renewable energy into the transmission grid.
    2.2. Consider operational rules of WEM in the assessment and forecast of TTCs required.
3. Improve the assessment of generation capacity options.

3.1. Continuously assess fuel supply situation (hydropower, natural gas, coal, nuclear fuel, renewable energy, etc.) to ensure fuel supply reliability.

3.2. Undertake a comprehensive mapping of biomass resources and assess the annual generation potential using municipal solid waste (MSW) as a resource for electricity.

3.3. Review and update the current wind and solar resource map.

3.4. Energy Commission to review its licensing conditions to enable collection of more granular data (e.g., heat rates, fuel prices, plant availability, emissions) from GENCos.

3.5. Implement a strategy to address in the short term the current overcapacity supply (in the light of existing PPAs).

4. Improve the assessment of distribution capacity expansion.

4.1. Undertake analysis at the customer level of granular data (e.g., customer load curves, etc.) for improved distribution planning.

4.2. Undertake an assessment of the implications of private sector participation (PSP) in electricity distribution on distribution planning

4.3. Undertake studies to assess the impact of proposed time-of-use rates on the operations of DISCos.

4.4. Continuously undertake appropriate studies to assess the level of integration of variable renewable energy into the sub-transmission grid.

4.5. Undertake studies to assess general impacts of solar PV installations and net-metering on electricity demand, sales revenue of DISCos, level of utilisation of network assets, etc. to help develop strategies to address the challenges.

5. Review regulatory and policy issues.

5.1. Pilot time-of-use rates with a small section of consumers and gradually scale it up.

5.2. Review fuel resource availability and procurement planning.

5.3. Integrate power and gas planning.

5.4. Review of renewable energy targets and support for renewable energy deployment.

5.5. Integrate G-NDCs into planning.

6. Review pricing issues.

6.1. Explore implications of WEM for wholesale electricity pricing.

6.2. Examine the implications of the ECG PSP.

6.3. Study the impact of fuel pricing on tariffs.

6.4. Clarify tariff structure and methodology.

7. Align plans.

7.1. Harmonise the assumptions, inputs, and recommendations for the IPSMP and the Annual Demand – Supply Plan.

7.2. Align recommendations and assumptions for the IPSMP and the Strategic National Energy Plan (SNEP), as well as the Transmission and Distribution Master Plans.

10. RISK MANAGEMENT AND RESILIENCE ACTION PLAN

An element of "risk" is present in every endeavour, particularly when deciding what new power plants to build in Ghana and when implementing the selected resource plan. To positively mitigate any negative effects of possible risks, it is important to keep the following activities in focus:

1. Identifying and evaluating risks early,
2. Developing mitigation options,
3. Selecting and implementing the optimal mitigation activities,
4. Monitoring of whether the mitigation activity is sufficient and is addressing the risks, and
5. Re-evaluating the risks.

This entire exercise of using the Integrated Resource and Resilience Planning (IRRP) approach is aimed at reducing power supply risks in Ghana while ensuring that the Least-Regrets option is selected. The resilience of the resource plan is evaluated by understanding how uncertainties—such as changes in demand growth, climate variability, changes in fuels prices and availability, regulatory changes, delays in power project implementation, operating power plants below their rated capacity, and other related factors—can affect the outcomes of interest (such as cost, new-build decisions, CO_2 emissions) through scenario analysis. Thus, the optimal resource plan resulting from the IRRP process is the "Least-Regrets" plan that is expected to be more resilient to changing circumstances and unexpected events as compared to a least-cost plan.

While many risks were considered in the modelling, this chapter provides a summary of the various external risks considered, and the external and internal risks for implementing the selected resource plan and the recommendations for procurement and planning. In addition, a subsection of this chapter addresses the risks and resilience issues associated with impacts of climate change on Ghana's power sector. Details of current and potential climate change impacts on the power system are discussed in the Appendix.

10.1. SUMMARY OF MAJOR RISKS TO GHANA'S POWER SECTOR

In Ghana, one of the greatest risks has been the lack of fuel supply security, especially during years of drought or less-than-average inflows into the dam reservoirs, during interruptions in gas supplies (both WAGP in the East and Ghana Gas in the West), and also changes or rising crude oil prices on the world market. To mitigate these risks, fuel supply diversity is needed; this is a key risk factor that has been evaluated in the model.

Table 54 summarizes the various risks that have been considered in the IPSMP modelling and the relevant mitigation measures.

Table 54: Risks and Mitigation Options for Ghana's Power Sector

No.	Risk Description	Model Sensitivity & Metric	Risk Mitigation Options
1	Fuel availability and price	High/low fuel prices and fuel availability	▪ Diversify fuel mix. ▪ Focus on indigenous resources because adding resource diversity through additional fuel imports has its own risks.
2	Climate impact – drought, floods, temperature increases	Higher demand, reduced water inflows	▪ Invest in improved weather prediction to ensure prudent management of dam reservoir. ▪ Diversify fuel mix and ensure fuel availability. ▪ Revise infrastructure design thresholds based on-site conditions and elevate the control room floors and other electromechanical equipment at various substations. ▪ Install guy wires to poles and other structures at risk-prone areas and create fire belts against bushfires.
3	Inadequate generation capacity	Unserved energy	▪ Maintain adequate reserve margin and timely implement the generation expansion plan and recommendations.
4	Transmission constraints	Transmission congestion	▪ Integrated planning that considers both generation and transmission expansions at the same time.

10.2. Summary of Climate Change Risks and Resilience Options

This subsection analyses the potential climate changes and impacts to the power sector at a sub-national scale, to better reflect the different climatological zones of the country and to better integrate with the IPSMP modelling. The four assessment zones, as determined for modelling of the power system using the Integrated Planning Model (IPM®), are depicted in Figure 78. The SouthEastGH and SouthWestGH zones are wetter and are subject to changes in sea level and storm surge heights. The NEDCo area climate is hottest and driest, and Middlebelt area has a more moderate climate relative to the extremes of its coastal and northern neighbours.

Figure 78: Sub-Regional Zones for Climate Change Analysis

By mid-century, Ghana's average annual temperature is projected to increase by 1.2 to 1.7°C.[51] Change in annual precipitation is more uncertain, as models disagree on the

[51] This represents the multi-model ensemble mean for RCP 4.5 ("low") and 8.5 ("high") scenarios, from KNMI Climate Explorer, relative to the 1986-2015 reference period.

sign of change. The multi-model averages indicate that there will be minimal changes in total annual precipitation (increases of 1 to 2%) but that precipitation will shift, with more rainfall occurring later in the year (October through December) and less occurring during the early part of the usual "rainy season" (April through June).

Like rainfall, projections for change in annual runoff and consecutive dry days (a proxy for drought) are mixed in sign and projected to change only minimally, although they are likely to shift in patterns similar to precipitation shifts. There is more certainty in projections in extreme rainfall, with the vast majority of models projecting increases throughout the country. Sea level rise is also projected to increase by around 0.4 to 0.7 m by mid-century.[52]

Based on the projected changes in climate conditions, potential impacts on Ghana's power system are identified, including direct and indirect impacts. Direct impacts represent those that directly disrupt the supply of electricity, such as damages to infrastructure from extremes; changes in seasonality or the annual amount of streamflow entering hydropower reservoirs; or temperature increases that reduce transmission and distribution efficiency. Indirect impacts are those impacts "facilitated" by climate stressors, for example, erosion and reservoir sedimentation due to intense precipitation events or loss of transmission towers due to heavy winds (facilitated by an ongoing extreme rainfall event).

These direct and indirect climate change impacts, not surprisingly, have implications on power planning. For example, the ultimate choice and timing of power investments could be influenced by climate impacts across the power system. In effect, the IPSMP has been designed to consider potential risks that may affect resources, capacity additions, and resource costs and prices to inform power system investments and planning over time.

Of the power system components, transmission and distribution infrastructure are particularly at risk to a range of climate impacts, especially assets located in low-lying coastal areas that may be exposed to rising sea level and storm surge heights, as well as increases in extreme rainfall, and temperature (see Figure 79). Taken in combination, projected increases in extremes (drought, flood, wind storms, or heatwaves) have the greatest potential to impose negative impacts across the power system because they are likely to increase demand while diminishing generation (in particular, hydropower) as well as transmission and distribution capacity.

To manage the impact of these climate stressors, a variety of adaptation measures can be applied. Measures range from no-regrets actions, which are proactive and beneficial to the power system regardless of climate change, to climate-justified measures, which include actions that might only be justifiable if expected changes in climate materialize.[53] Types of

[52] Figure 13.20 in Church, J., P. Clark, A. Cazenave, J. Gregory, S. Jevrejeva, A. Levermann, M. Merrifield, G. Milne, R. Nerem, P. Nunn, A. Payne, W. Pfeffer, D. Stammer and A. Unnikrishnan, 2013: Sea Level Change. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T., D. Qin, G. Plattner, M. Tignor, S. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom.

[53] World Bank. 2009. *Water and Climate Change: Understanding the Risks and Making Climate-Smart Investment Decisions*.

adaptation measures include policy and planning, operation and maintenance, technological, and structural.

Some of these measures have already been captured under Ghana's Nationally Determined Contribution (G-NDC), which highlights sustainable energy security as one of its priority sectors.[54] While the document primarily describes sustainable energy security as a mitigation action, the energy resource diversification is option that would enhance the resilience of the energy system. The document also highlights several policy actions that are aimed at achieving the country's adaptation goals and would lead to enhanced energy resilience, as listed in Table 55. This document is complemented by Ghana's more recent *National Climate Change Adaptation Strategy*, which lists energy sector adaptation on the demand- and supply-side as a priority programme.[55]

Figure 79: Summary of Relative Risk of Climate Stressors to Ghana's Power System

Climate Stressor	Generation			Transmission & Distribution	Demand
	Hydro	Thermal	Renewables		
Extreme Rainfall, Flooding, & Sedimentation	High	High	High	High	Low
Drought	High	Med	High / Low*	Med	High
Sea Level Rise & Storm Surge	Low	High	Med	High	Low
Temperature	Med	Med	Med / Low**	Med	High
Water Flow, Volume, & Timing	High	Low	High / Low*	Low	Low

*Biomass is highly sensitive to drought and rainfall/flow variability/timing, while solar and wind have lower sensitivity
**Biomass has a higher level of sensitivity to temperature than solar and wind

Table 55: Ghana's Adaptation and Mitigation Policy Actions in the Ghana-NDC (2015)

Mitigation Policy Actions	Adaptation Policy Actions
▪ Scale up renewable energy penetration by 10% by 2030. ▪ Promote clean rural household lighting. ▪ Expand the adoption of market-based cleaner cooking solutions. ▪ Double energy efficiency improvement to 20% in power plants.	▪ Instigate city-wide resilient infrastructure planning, including energy. ▪ Implement early warning and disaster prevention, including expanding and modernising 22 synoptic stations based on needs assessment, and increasing number to 50 stations for efficient weather information management. ▪ Integrate water resources management.

[54] Republic of Ghana. 2015. Ghana's nationally determined contribution (G-NDC) and accompanying explanatory note.

[55] UNEP and UNDP 2016.

Power planners need to recognise limitations and uncertainties when gathering and applying climate information to inform their decision-making and investments. In Ghana, climate change projections are particularly uncertain for future changes in annual precipitation and runoff volumes, although there is higher confidence on projections of more frequent and intense rainfall that may lead to flooding. In addition, available, accessible, and useful data are lacking to conduct meaningful climate analysis in many locations in Ghana. However, uncertainty or lack of complete data are not a reason for inaction. Rather, planning robust strategies is needed to prepare for uncertain futures.

To be efficient with time and resources, power sector stakeholders can take a hierarchical approach that moves from high-level risk screening (country, power sector-level screening) to more detailed assessment where risks may be more consequential (e.g., project analysis and engineering design). Climate vulnerability and risk analyses can increase in detail, focus, and complexity (and cost) during successive project planning stages, depending on the degree of potential risk identified through screening in earlier stages. The IPSMP and the Least-Regrets Strategy represents a high-level risk screening analysis, which identifies key vulnerabilities that power planners should be aware of and take into consideration in the Master Plan.

Table 56, Table 57, and Table 58, show some of the illustrative adaptation options for generation, transmission and distribution, and DSM.[56] Table 59 shows the estimated costs of several adaptation strategies that could be relevant for Ghana's power sector.

Table 56: Adaptation Strategies Applicable to all Generation Types

JUSTIFICATION	TYPE	ADAPTATION STRATEGY	ALREADY PURSUING?
No-regrets	Technology	Invest in improved short-term (daily/monthly) weather prediction to improve load forecasts and operational management.	N
		Use seasonal and annual weather forecasts to improve hydropower reservoir management.	Y
	Policy & Planning	Plan for provision of standby energy equipment and backup restoration supplies, as part of ancillary services.	N
		Allow for flexible maintenance schedules for thermal generation to account for changing rainfall patterns due to climate change.	N
		Ensure that drafting of individual hydropower reservoirs are consistent with the expected long-term average of storage capacities, considering potential climate change impacts.	N
Low-regrets	Policy & Planning	Choose generation infrastructure sites that are not at high climate exposure risks, accounting for projected changes in coastal and riverine flooding.	N

[56] Based on tables from MCC, 2016. Original sources include Ebinger and Vergara, 2011; Hammer et al., 2011; Seattle City Light, 2013; USAID, 2012; U.S. DOE, 2016; and WECC, 2014.

		Review and update power infrastructure design thresholds using climate change projections.	N
	Structural	Install backup systems for critical hospital and home needs.	Y
		Invest in decentralised power generation (e.g., rooftop PV).	Y
		Expand networks, network protection, and energy storage to enhance reliability.	Y
		Build additional generation capacity to account for decreased generation efficiency or increased customer loads due to climate impacts.	N
Climate-justified	**Policy & Planning**	Ensure adequate backup generation and cooling systems for plants facing increased exposure to flooding, drought, and other extremes.	N
	Structural	Relocate or reinforce key generation infrastructure to reduce exposure and sensitivity to sea level rise, storm surge, extreme precipitation and floods, drought, extreme temperature, and other extreme weather events.	N

Table 57: T&D Adaptation Strategies, Independent of Climate Stressors

JUSTIFICATION	TYPE	ADAPTATION STRATEGY	ALREADY PURSUING?
No-regrets	Technology	Automate restoration procedures to bring energy system back on line faster after weather-related service interruption.	N
	Operations & Maintenance	Regularly inspect vulnerable infrastructure (e.g., wooden utility poles).	Y
		Update ageing transmission and distribution equipment.	Y
		Invest in improvements to short- and medium-term weather, climate, and hydrologic forecasting to improve lead times for event preparation and response.	N
Low-regrets	Operations & Maintenance	Increase resources for more frequent maintenance.	Y
	Structural	Support variable and distributed generation, through smart grid improvements.	Y
		Build additional transmission capacity to cope with increased loads and to increase resilience to direct physical impacts.	Y
		Build additional generation capacity to account for increased line losses and weather-related infrastructure damage.	N
		Install guy wires to poles and other structures at high climate risk areas.	Y

Table 58: Demand-Side Management Adaptation Strategies

JUSTIFICATION	TYPE	ADAPTATION STRATEGY	ALREADY PURSUING?
No-regrets	Policy and Planning	Establish public education programmes to promote lifestyles that are less energy-dependent.	Y
		Explore energy market mechanisms to meet demand. Consider power exchange agreements, spot market purchases, and options purchases.	Y
		Establish or expand demand-response programmes which encourage consumers to voluntarily reduce power consumption during peak demand events.	N
		Time-of-use tariffs to encourage consumers to reduce power consumption during peak hours.	N
		Improve and enforce energy-efficient building codes.	Y
		Adopt mandatory minimum energy performance standards for appliances (including air conditioners).	Y
		Adopt mandatory minimum energy performance standards for commercial buildings.	N
	Structural	Install smart metres and smart grid equipment to reduce power consumption during peak demand events.	N
		Employ passive building design architecture to maintain comfort or lighting levels even in situations where energy system losses occur.	N

Table 59: Estimated Cost of Adaptation Strategies

JUSTIFICATION	TYPE	ADAPTATION STRATEGY	Cost Min.	Cost Max.	Unit
No Regrets	Policy, Planning, & Operations	Residential energy reporting, bounty/recycling, and rebate programs	$50	$2,250	MWh
Low-regrets	Policy, Planning, & Operations	Advance metering infrastructure	$240	>$300	smart meter
		Vegetation management	--	$12,000,000	mile
		Backup substation generators	--	$20,000	substation
		Annual transmission/distribution patrols	$136,000	$2,760,000	year
	Structural	Installing guy wires	$600	$900	pole
Climate Justified	Structural	Using submersible equipment	--	>$130,000	vault
		Upgrading wood poles	$16,000	$40,000	mile
		Upgrading transmission lines	--	>$400,000	mile
		Undergrounding transmission & distribution lines	$100,000	$30,000,000	mile
		Substation hardening	--	$600,000	substation
		Substation elevation	>$800,000	>$5,000,000	substation
		Building new substation	--	$6,000,000	substation
		Reinforcing existing floodwall	--	$8,000,000	seawall
		Building new floodwalls	--	$4,000,000	mile
		Installing microgrid	--	$3,750,000	MW

10.3. IPSMP Implementation Risks and Mitigation

There are a number of external and internal risks to the implementation of the Master Plan. This subsection discusses some of the possible internal and external risks to implementing the Annual Demand-Supply and the IPSMP plans, and how they could be addressed by the Ghana power sector agencies. The internal risks for the implementation of the IPSMP include:

1. Under-recovery of cost of operations by the distribution agencies is crippling the financial capacities of the GENCos and the grid operator, thereby constraining the timely implementation of recommendations
2. Continued investment in old planning tools/processes and challenges in securing funding for procuring new planning tools, leading to difficulty in the adoption of new planning methods
3. Barriers to seamless exchange of information between various agencies
4. Labour turnover in the power sector has increased with the increased participation of IPPs who tend to recruit from existing staff of the various agencies
5. Inadequate human capacity (to adequately interpret outputs of analytical models) as a result of inadequate training budgets due to the financial challenges currently facing the sector

The external risks for the implementation of the IPSMP include:

6. Potential influence and interference of vested interests and lobbyists
7. Variations in fuel prices beyond the assumptions in the sensitivity analysis
8. Variations in demand forecast beyond the assumptions in the sensitivity analysis
9. Introduction and cost of new technologies
10. Dependency on USAID for technical support

11. Cost of renewal of software licenses, and continued need for IPM trainings and support

Table 60 summarises the potential mitigation options to deal with the various internal and external risks that could affect the implementation of the IPSMP recommendations.

Table 60: Implementation Risks and Their Mitigation Options

No.	Risk	Risk Mitigation Options
1	Inadequate funding	▪ Improve the financial position of the off-takers, particularly ECG. ▪ Promote higher revenue collection rate of the DISCos to ensure better cash flow. ▪ Promote reduction in the revenue-cost gap by full implementation of cost recovery tariffs (without broad subsidies).
2	Influence of vested interests and lobbyists	▪ Promote awareness and sensitisation among decision makers and politicians on the need to adhere to the planned Generation Expansion Plan. ▪ Project developers and lobbyists shall ensure that their proposals are consistent with sector's development plans.
3	Labour turnover and wrong/opaque succession planning	▪ Improve working environment, clarity in human resource development programmes, and clear succession planning.
4	Technological change	▪ Review regularly new technologies and their maturity (by the PPTC). ▪ Ensure adequate capacity building and appropriate standardisation of equipment to minimise cost of inventory. ▪ Develop capacity in-country for over-hauling of major plant and equipment.
5	Barriers to exchange of data and planning in "silos"	▪ Improve sector collaboration and participation in data collection and Power sector planning. ▪ Use standard templates and surveys in gathering data. ▪ Develop consensus on input assumptions for modelling, reviewing of basis for relevant technical data and model outputs analysis. ▪ Encourage seamless exchange of information between agencies.
6	Significant variations in demand forecasts and fuel price assumptions	▪ PPTC to review modelling inputs on an annual basis to assess whether the sensitivities in the model represent expected variations based on current world factors.
7	Dependency on USAID	▪ Sustain capacity building for power sector agencies before the IRRP Project ends. ▪ Ensure post-IRRP relationship between USAID and Ghana Power sector agencies is mutually beneficial, as part of the new USAID contract to support Ghana's power sector planning.
8	Software license renewal costs	▪ USAID could cover the costs of the 2020-2022 license renewal for IPM. ▪ USAID's new Ghana project can support future renewals of IPM. ▪ GRIDCo and EC, on behalf of the PPTC, could procure future annual renewals.