Integrated Power System Master Plan for Ghana

Volume #2

Main Report (2018 Final)

May 2019 (Final version)

DISCLAIMER

FOREWORD

Electricity, as a versatile form of modern energy, is a critical ingredient for economic growth. Therefore, increasing the availability of, and access to, electricity at an affordable price is a high-priority objective within the national planning processes in many developing countries, including Ghana. A specific and concerted focus on enhancing Ghana's power sector has resulted in significant gains in installed generation capacity, access to electricity (at about 84% as of the end of December 2017) since Ghana's independence.

Planning for the effective development of the electricity sub-sector is considered the single most important activity because it can facilitate sustained economic growth. Consequently, electricity sector planning is paramount to Ghana's overall energy system planning.

The Energy Commission, which was established by the Energy Commission Act 1997 (Act 541), has the statutory responsibility to, inter alia, prepare, review, and periodically update indicative national energy plans, which will provide the framework to ensure that all reasonable energy demands of the economy are met in a sustainable manner.

Prior to the enactment of the Volta River Authority (Amendment) Act 2005, in line with the Power Sector Reforms, the Volta River Authority (VRA) had the mandate to plan specifically for sufficient electricity supply to meet the country's demand and the Electricity Company of Ghana (ECG) and Northern Electricity Distribution Company (NEDCo) had responsibility for power distribution in the country. The Power Sector Reforms acknowledged the need for an independent Nationally Interconnected Transmission System (NITS) and the important role of a national transmission operator (Ghana Grid Company Ltd. [GRIDCo]) in planning for the operation and management of the NITS.

These agencies (Energy Commission, VRA, Bui Power Authority [BPA], ECG, NEDCo, and GRIDCo) have been involved in electricity system planning process in recent years. To address the challenges of the electricity supply shortfall in 2012–2016, the sector Ministry got involved in the procurement of power plants. The power supply shortages were caused by a combination of challenges, which included non-adherence to developed plans, including the 2006 Strategic National Energy Plan (SNEP), erratic supply of natural gas (fuel shortages), low water levels in the hydropower dams due to over-drafting of the reservoir, technical challenges at the thermal plants, and most critically, financial challenges (e.g., inability to pay for gas and liquid fuels imports) in the power subsector.

In an effort to address these challenges, the Ghana Integrated Power Sector Master Plan (IPSMP) has been developed jointly by the Ghana energy sector agencies. The ISPMP was led by the Energy Commission and the Ministry of Energy, with support from the United States Agency for International Development (USAID) through the USAID/Ghana Integrated Resource and Resilience Planning (IRRP) project, which was implemented by the U.S. consulting firm, ICF.

The IPSMP is considered as a subset of the SNEP, which is updated by the Energy Commission periodically. The short-to-medium term Annual Supply – Demand plans, which are jointly developed by Ghana Grid Company (GRIDCo) and the Energy Commission as the lead agencies, have also informed the development of the IPSMP.

The vision of the IPSMP is to develop a resilient power system, which reliably meets Ghana's growing demand for power in a manner that supports the country's sustainable economic development.

It is expected that the IPSMP will be updated on a regular basis (at least every three years), and the IPSMP, along with SNEP and the Annual Supply – Demand plans, will form the basis for the development of the power sector going forward.

A. K. Ofosu Ahenkorah, Ph.D.
Executive Secretary
Energy Commission

6 December 2018

ACKNOWLEDGEMENTS

The Integrated Power Sector Master Plan (IPSMP) was developed by the Energy Commission, with financial and technical support from USAID, Ghana, through its funding of the Integrated Resource and Resilience Planning (IRRP) project. The IRRP project is being implemented by ICF[1], a US-based consulting firm. We wish to express our gratitude to USAID Ghana Mission, for sponsoring the IRRP project with support from Power Africa. The feedback received from the USAID's local Energy Team (Waqar Haider, Mark Newton, Dorothy Yeboah Adjei, Richard Chen, and Robert Buzzard) has been very helpful during the IPSMP development.

The Energy Commission and the IRRP project would like to acknowledge the important role of the Ministerial officials from the Sector Ministry in their sustained support for the development of the IPSMP and the guidance provided to the IRRP's Steering and Technical Committees.

The IRRP project would like to thank the management and key officials of the following stakeholder institutions, which include VRA, BPA, GRIDCo, ECG, NEDCo, EPC, PURC, EC, GNPC, and GNGC, for active participation in various activities associated with the development of the IPSMP. The IRRP Steering and Technical Committees (see below) were formed from these agencies, and these members contributed their time generously to ensure that this IPSMP is successfully developed in an inclusive manner. They are also commended for allowing their staff to work closely with the IRRP project, and to provide the necessary data for the IPSMP modelling. All other stakeholders who provided data and specific suggestions that helped to shape the project are also duly acknowledged.

The IPSMP report was based on ICF's planning modelling tool, the Integrated Planning Model (IPM®), for which ICF is 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 they are all gratefully acknowledged.

Ministerial Oversight

Name	Institution	Designation
Hon. John Peter Amewu	Ministry of Energy	Minister of Energy
Hon. William Owuraku Aidoo	Ministry of Energy	Dep. Minister of Energy
Hon. Dr. Amin Adam	Ministry of Energy	Dep. Minister of Energy
Hon. Joseph Cudjoe	Ministry of Energy	Dep. Minister of Energy
Hon. Boakye Agyarko	Ministry of Energy	Former Minister of Energy
Hon. John Jinapor	Ministry of Energy	Former Dep. Minister of Energy/Power

[1] www.icf.com

Name	Institution	Designation
Mr. Lawrence Apaalse	Ministry of Energy	Chief Director
Prof. Thomas Akabzaa	Ministry of Energy	Former Chief Director
Mr. Solomon Asoalla	Ministry of Energy	Former Chief Director

Steering Committee

Name	Institution	Designation	Position
Dr. Nii Darko Asante	Energy Commission	Technical Director	Chairman
Samuel Sarpong*	PURC	Former Executive Secretary	Member
Maame Dufie Ofori	PURC	Executive Secretary	Member
Jabesh Amissah-Arthur*	Bui Power Authority	Former Chief Executive Officer	Member
Fred Oware	Bui Power Authority	Chief Executive Officer	Member
William Amuna*	GRIDCo	Former Chief Executive Officer	Member
Jonathan Amoako-Baah	GRIDCo	Chief Executive Officer	Member
Robert Dwamena*	ECG	Former Managing Director	Member
Samuel Boakye-Appiah	ECG	Managing Director	Member
Frank Akligo	NEDCo	Ag. Managing Director	Member
Kwaku Wiafe	Volta River Authority	Manager	Member
Prof. Thomas Akabzaa*	Ministry of Energy	Former Chief Director	Member
Lawrence Apaalse	Ministry of Energy	Chief Director	Member

Note: * indicates members who were substituted during the course of the project

Technical Committee

Name	Institution	Designation	Position
Dr. Joseph Essandoh-Yeddu	Energy Commission	Director, SPPD	Chairman
Abdul Noor Wahab	VRA	Manager, System Planning	Member
Peter Acheampong	BPA	Manager, Dams Operation	Member
Benjamin Ahunu	GRIDCo	Principal Engineer	Member
Godfred Mensah	ECG	Manager, System Planning	Member
Mawunyo Rubson	MiDA	Director, Generation Projects	Member
Moses Tawiah	NEDCo	Director, Engineering	Member
Tampuri Tayeeb	NEDCo	Planning Engineer	Member
Nutifafa Fiasorgbor	PURC	Principal Regulatory Engineer	Member
Sulemana Abubakar	MoEn	Deputy Director, Materials	Member
Kwasi Twum-Addo	MoEn	Director, HSSE	Member

ICF Ghana (IRRP Project Team)

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

ICF U.S. Experts

Name	Designation
Juanita Haydel	IRRP Senior Adviser
Maria Scheller	Modelling Expert
Ken Collison	Generation &Transmission Expert
Molly Hellmuth	Climate Change/Resilience Expert

Sub-Consultants (Energy Foundation)

Name	Designation
Ernest Asare	Executive Director
Stephen Doudu	Technical Director
Isaac Opoku Manu	Assistant Program Manager

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	Compagnie Ivoirienne d'Electricité
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
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	Photo-Voltaic
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 oil and gas fields
TICo	Takoradi International Company
TSO	Transmission System Operator
TSC	Transmission Service Charge

TTC	Total Transfer Capability
TWh	TeraWatt-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 Aluminium 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

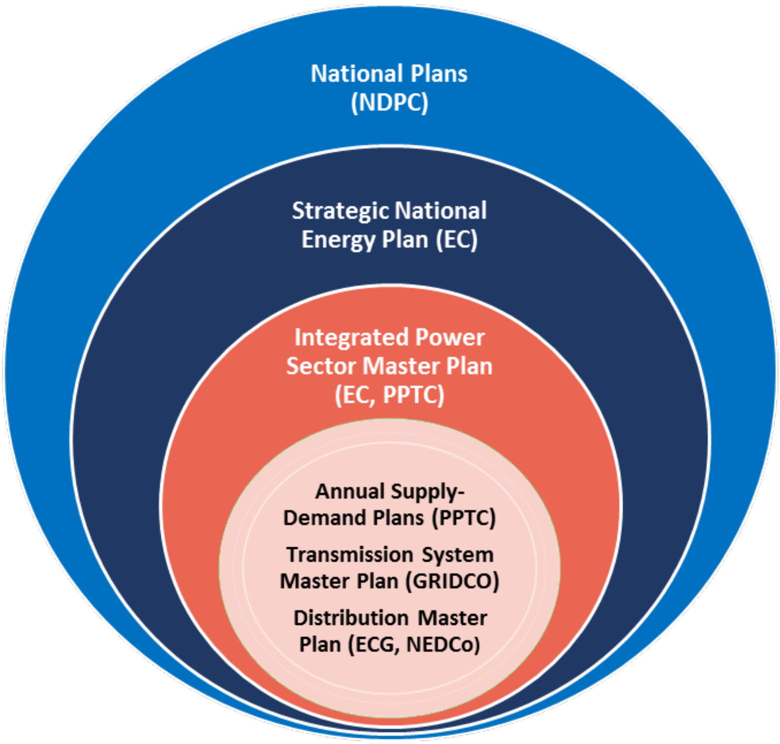
1. GHANA INTEGRATED POWER SECTOR MASTER PLAN

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. It is more than just an exercise in updating supply-demand forecasts for electricity and developing a list of projects that are needed to meet future demand. In addition, the IPSMP is rooted in sound technical analyses that consider various risks and uncertainties in a systematic manner.

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 action plans for Ghana's power sector development.

The IPSMP also fulfils the Ministry of Energy's policy objective to develop an Integrated Power Subsector Master Plan (IPSMP) to be developed in a **coordinated manner in accordance with an integrated subsector Master Plan**. Power subsector plans shall be harmonised into a single comprehensive Master Plan based on a power demand scenario agreed to by all key stakeholders.

Figure 1: IPSMP in the Hierarchy of Power Sector Planning



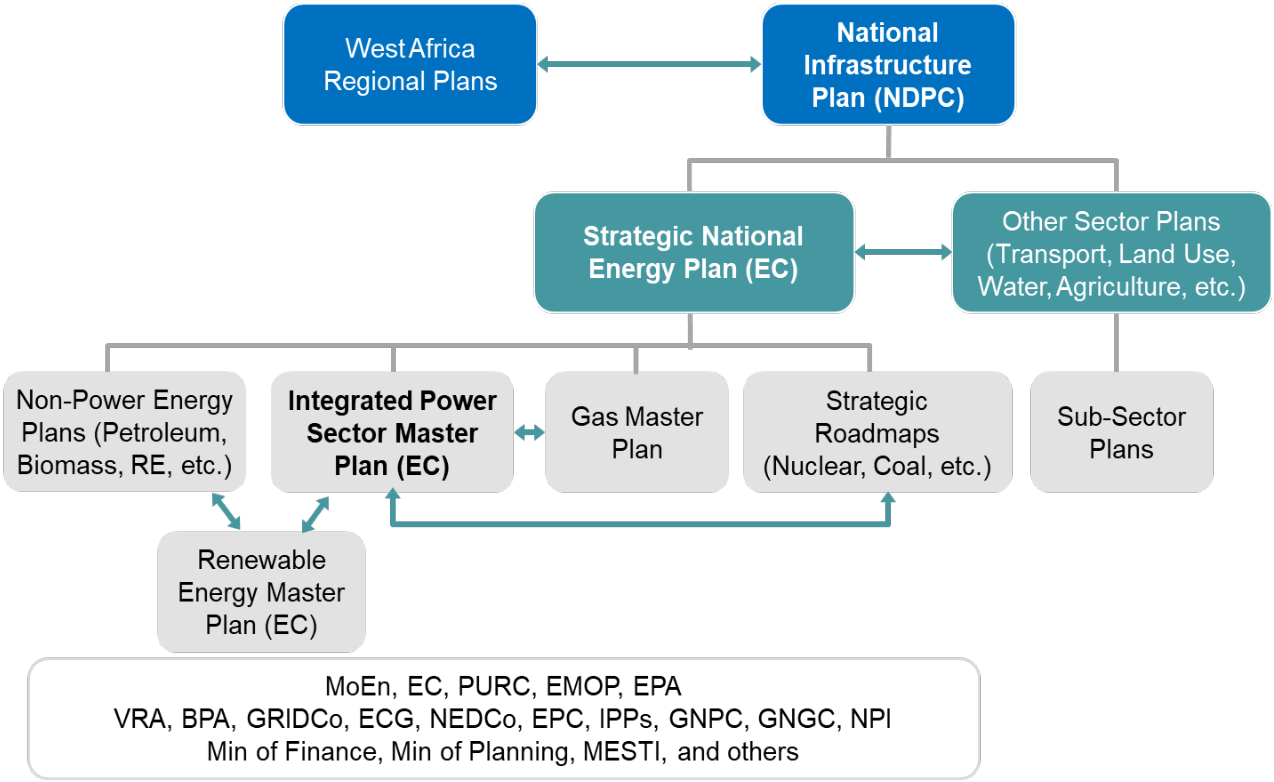
The IPSMP forms part of the Energy Commission's Strategic National Energy Plan (SNEP), and it is expected that the Annual Supply Plans, the Transmission Master Plans, and the Distribution Master Plans will be based on the same assumptions and inputs used to develop the IPSMP (see Figure 1). It is also expected that the broader plans, such as the Gas Master Plan and the Renewable Energy Master Plan, as well as strategic roadmaps, such as the nuclear roadmap, would be consistent with the inputs and results of the IPSMP (see summarises the potential mitigation options to deal with the various internal and external risks that could affect the implementation of the IPSMP recommendations.

Table 51: Implementation Risks and Their Mitigation Options).

To achieve this, the underlying drivers in the power and its related sectors will need to be captured as inputs to the SNEP and IPSMP. Policy imperatives in other sectors (e.g., water, transportation, land use, agriculture) will contribute to the inputs for the SNEP, but the IPSMP will govern the power sector landscape of plans for these other sectors. At a regional level, plans across West Africa (e.g., the WAPP Master Plan) can also impact the development and planning of the SNEP and IPSMP in Ghana. The major stakeholders for developing the IPSMP are shown at the bottom of summarises the potential mitigation options to deal with the various internal and external risks that could affect the implementation of the IPSMP recommendations.

Table 51: Implementation Risks and Their Mitigation Options.

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



Based on the development process for this IPSMP, the Ghana power sector agencies are expected to develop a more coordinated power sector planning process and implementation, and recommendations for such planning are discussed in this IPSMP.

The process of the development of the Master Plan is of as much importance as the content of the plan itself, because the buy-in and eventual implementation of the IPSMP are dependent on the involvement of the key power sector stakeholders and institutions. Therefore, the EC has led the development of this IPSMP, with support from the Integrated Resource and Resilience Planning (IRRP) Project, which is being implemented by the U.S.

consulting firm, ICF,[2] and funded by the United States Agency for International Development (USAID).

A Steering Committee and a Technical Committee were constituted by the Ministry of Power in 2016 to provide policy and technical guidance and review of the IPSMP development. The members of the Committees were from all the key stakeholders for the Ghana power sector, and was chaired by the EC. These committees have reviewed and approved this IPSMP.

Broad stakeholder workshops were held to seek feedback on the draft versions of the report, and inputs from these workshops have been included in the final version.

Any Master Plan, including this IPSMP, is always developed in a state of incomplete information, and therefore the IPSMP outlines a staged process of information and institutional development. This IPSMP identifies potential "decision-trees" and critical factors that are dependent on additional information that should be gathered and analysed over time. Therefore, regular updates of the IPSMP are necessary to address the changes and new challenges in the power sector over time. It is anticipated that the Ghana IPSMP will be updated at least every 3 years.

The backbone of the IPSMP is the output of the technical analyses that were conducted using a dynamic, linear optimisation tool called the "Integrated Planning Model (IPM®)" that relies on sectoral data to simulate the operations of Ghana's power system in the mid- to long-term planning horizons. As a combined production cost and capacity expansion simulation model, IPM projects plant generation levels, new power plant construction, fuel consumption, and inter-regional transmission flows using a linear programming optimisation routine with dynamic effects, while also considering various operational and contractual constraints.

Beyond the modelling work, the IPSMP also contains other elements related to implementation of the plan, including recommendations for procurement, institutional arrangements, financing, inter-ministerial coordination, and M&E in the framework of a decision hierarchy.

1.1. IPSMP Vision and Objectives

The vision of the 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;

[2] See: www.icf.com.

6. Promote and implement sustained energy efficiency and demand-side management (DSM) programmes; and
7. Support secondary objectives beyond current universal access goals (e.g., productive uses of electricity, household-level connection, mini-grids).

The IPSMP vision and objectives are aligned with the Government of Ghana's 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 IPSMP

The IPSMP development process was very consultative, and to the extent possible, all activities were discussed comprehensively; decisions on modelling framework, inputs, and results were therefore consensus-driven. To develop the IPSMP, the Ministry of Energy (MoEn) relied on support from USAID, through the IRRP Project. The USAID support for the IRRP Project rested on the mutual resolution by the Government of Ghana and United States Government that resulted from deliberations at the Partnership for Growth (PFG) Initiative (Partnership for Growth, Joint Country Action Plan, 2013).[3]

The Government of Ghana, working through the MoEn, appointed the EC as the focal agency on the IRRP Project; and the U.S. Government, working through USAID, contracted ICF, a U.S. consulting company, to provide consultancy services for the project.

Data and analysis of the power supply, demand, and transmission in Ghana was put into a least-cost optimisation planning tool that is conducive for scenario analysis. Resilience of the power system was evaluated by understanding how uncertainties and risks can impact least-cost outcomes through scenario analysis. A "Least-Regrets" solution for capacity expansion for Ghana's power sector was determined by evaluating how different policies and strategies for the future development of the Ghana power sector will react under varying sensitivities. In essence, a Least-Regrets Strategy has the overall best 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 IPSMP. The MoEn and EC established the working relationships for the IRRP Project, and they are illustrated in Figure 4.

[3] The PFG is a U.S. Government development policy model piloted in four countries: the Philippines, El Salvador, Tanzania, and Ghana. This initiative provided a new framework for deepening and strengthening the U.S.–Ghana bilateral engagement on promoting Ghana's broad-based economic growth and inclusive development.

Figure 3: Framework for IRRP

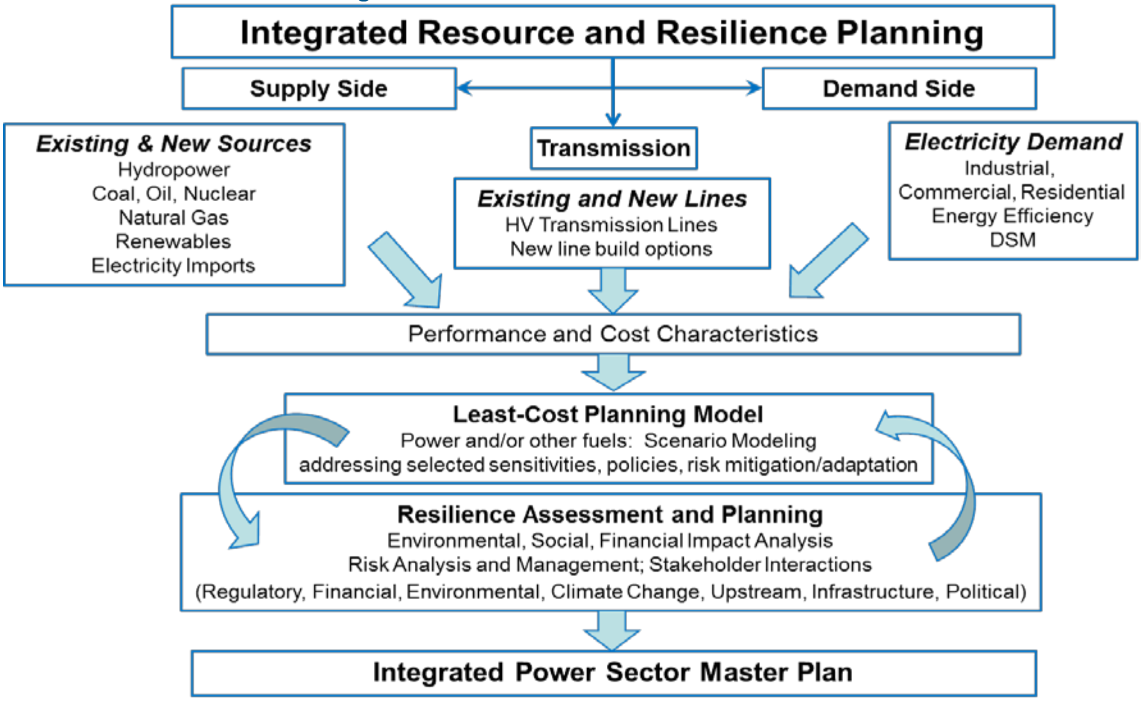
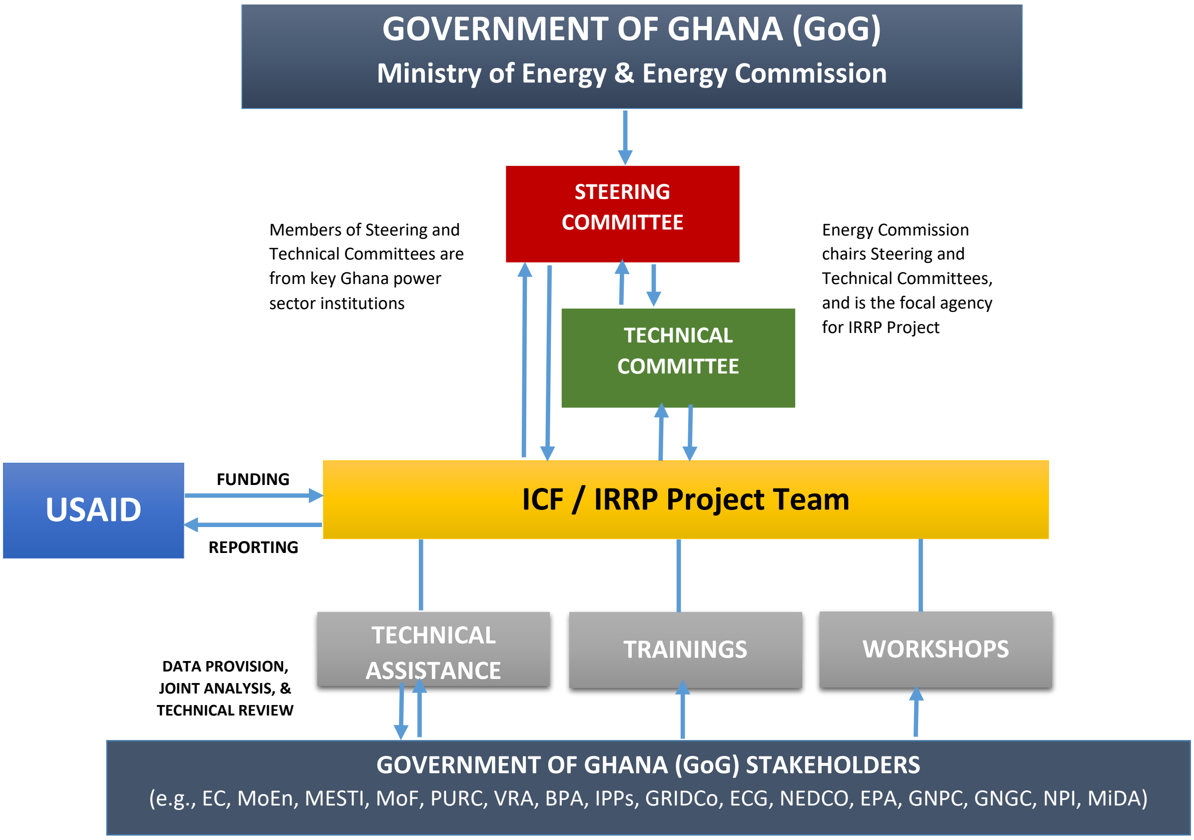


Figure 4: Working Relationships for the IRRP Project



In June 2016, the sector ministry constituted two standing committees—the Steering Committee and the Technical Committee—for the IRRP Project. The Steering and Technical Committees comprised personnel nominated by the relevant Ministries and power sector agencies (MoEn, MoF, MESTI, VRA, BPA, GRIDCo, ECG, NEDCo, EC, PURC, MiDA, and EPA) by request of the sector ministry.

The Steering Committee had the mandate to provide the necessary policy guidance in the implementation of project activities while the Technical Committee focused on the technical deliberations as well as hands-on support to the IRRP Project team. The focal Agency in the IRRP Project implementation process was the EC, the mandated institution for planning in Ghana's energy sector, which includes the power subsector. In light of this, both the Steering and Technical Committees were chaired by the EC. Six meetings of the Steering Committee and seven meetings of the Technical Committee were held since September 2016, in preparation of the IPSMP.

The choice of the modelling tool, the IPSMP vision and objectives, the IPSMP outline, and the modelling results were all discussed at the Technical Committee meetings, with policy and supervisory guidance provided by the Steering Committee.

The data used in the Ghana-IPM and other related analyses were collated from the various stakeholder institutions in the power sector, with support from the Technical and Steering Committees. Where necessary, data were also obtained online from reputable websites. All of the data were carefully vetted and discussed with the source agencies to confirm their validity and integrity. As such, the IRRP Project initiated, collated, reviewed, and analysed the data, with oversight and feedback from the EC and Technical Committee.

1.2.1. Feedback and Update Process for IPSMP

Preliminary drafts of the IPSMP were reviewed by the Technical and Steering Committees in early 2018, and the draft IPSMP was submitted by the EC to the MoEn for its review in August 2018. Following the Ministry's review, broad stakeholder meetings were held, and the final version was released by the Energy Commission, upon approval by the Steering Committee.

It is expected that this IPSMP will be updated on regular basis (ideally every 3 years). However, the first update is expected to be complete by the end of 2019. Additional training on the IPM and ongoing analyses to support the Ghana stakeholders will continue in 2018 and 2019.

1.3. Organisation of the IPSMP Report

The information in the report is 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 for decision makers and highlights key issues such as the goal and objectives of the IRRP Project, the vision and objectives of the IPSMP, and the various attributes of the IPSMP, which include the Least-Regrets Portfolio, short-term action plan for implementation, hierarchy of recommendations to facilitate the IPSMP implementation, recommendations for future planning and procurement in the power sector, climate change risk assessment and management, and monitoring and updating of IPSMP.

Volume 2 starts with 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 analyses 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 business-as-usual 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. 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 IPSMP in a stand-alone set of appendices.

2. Background and Key Issues

2.1. The Ghana Power System

Electricity supply in Ghana started in 1914 at Sekondi[4] as an isolated stand-alone power station and then extended to various towns. In the 1920s and 1930s, small oil-powered plants provided supply in Accra, Cape Coast, Koforidua, Kumasi, and Tamale. On 1 April, 1947,[5] the Electricity Company of Ghana (ECG) (at that time, the Electricity Department) took over the responsibility of distribution of power in the entire country from the Public Works Department and the Railway Administration.

The first high-voltage overhead sub-transmission line to be commissioned in the country was an 11 kV line between Accra and Nsawam in 1949. Ghana's largest power plant just before independence was the Tema power station, commissioned in 1956 with a 3 x 650 kW (i.e., 1.95 MW) generating set (gen-set); the station's capacity was extended to 35.3 MW by the mid-1960s. The first 161 kV transmission system was built in 1963 to move power from the Tema power station to Accra.[6]

The development of hydropower in the country started in 1961 with construction of four units of total capacity of 588 MW on the Volta River at Akosombo. These units were connected to the 161-kV grid to transmit power to meet the demand in the country. The construction of the 588-MW hydropower plant was completed in 1965 and was operated by the Volta River Authority (VRA). In 1965, about 75% of the power generated in the country was consumed in Accra and Tema, primarily by Volta Aluminium Company (VALCo) located at Tema.

In 1972, two additional hydropower units (i.e., units 5 and 6) with a total capacity of 324 MW were constructed and commissioned to bring the total hydropower capacity in the country to 912 MW.[7] After the commissioning of the hydropower plant, ECG decommissioned the isolated diesel power stations in the country because it was supplying grid-based power from VRA for distribution to the various towns from the transmission network that was being extended to various parts of the country.

The third phase of hydropower development in the country started in November 1977 with the construction of four turbine units (with a total capacity 160 MW) at Kpong, downstream of the Akosombo Dam on the Volta River. The project was completed in December 1981 and brought the total hydropower capacity in the country to 1072 MW.[8] The Akosombo hydro power plant was retrofitted, upgrading its total capacity from 912 MW to 1020 MW by 2005.[9] Hydropower development in the country continued with the commencement in May 2007 of the construction of three units, with total capacity of 400 MW, on the Black Volta at Bui.

---

4 See: http://www.ecgonline.info/index.php/about-us.html (accessed November 13, 2017).

5 Ibid.

6 Ibid.

7 https://www.vra.com/resources/annual_reports.php

8 Ibid.

9 Ibid.

When the project was completed and commissioned in December 2013, the total installed hydropower capacity in the country was up to 1580 MW.[10]

Power Sector Reforms was initiated by the Government of Ghana in 1994 to, among other purposes, reduce the increasing pressure on the Government of Ghana to secure timely and adequate funding for investment in the power sector, which had started experiencing delays in the implementation of expansion plans. The sector reform was also expected to transform the vertically integrated structure of the power sector into one that allowed for the entry of independent power producers (IPPs). These IPPs were expected to bring private sector investment into the energy sector, thereby increasing the generation capacity to ensure the availability of reliable power supply. Until this time, investments in the sector had been made largely by VRA (a vertically integrated state-owned power generation monopoly) with support from the Government of Ghana, mainly through sovereign guarantees.

In furtherance of the Power Sector Reforms, the Public Utilities Regulatory Act, 1997 (Act 538) was enacted to establish the Public Utilities Regulatory Commission (PURC). The charge of PURC, inter alia, is to regulate the provision of utility services in the electricity and water sectors. The Energy Commission (EC) was also established in 1997 by the Energy Commission Act, 1997 (Act 541) to regulate and manage the development and utilisation of energy resources in Ghana as well as to provide the legal, regulatory, and supervisory framework for all providers of energy in the country. The EC, under Section 2.2(c) of Act 541, is mandated to “prepare, review and update periodically indicative national plans to ensure that all reasonable demands for energy are met”. The Act also mandates the EC to grant licences for the construction and operation of all transmission, wholesale electricity supply, and distribution assets within the sector and to enforce performance standards (technical and operational rules of practice) of the utilities.

Hence, the way was paved for the first IPP (CMS Generation of Michigan, an American company) to execute a joint venture deal with VRA (90% CMS and 10% VRA) to operate in the country’s power sector. A special purpose vehicle, Takoradi International Company (TICo),[11] was founded to operate the first 220-MW simple cycle thermal power plant built at Aboadze, Takoradi in the year 2000. This plant has, since 2015, been expanded to a 330-MW combined cycle power plant with the addition of heat recovery steam generation (HRSG) and steam power generation plants.

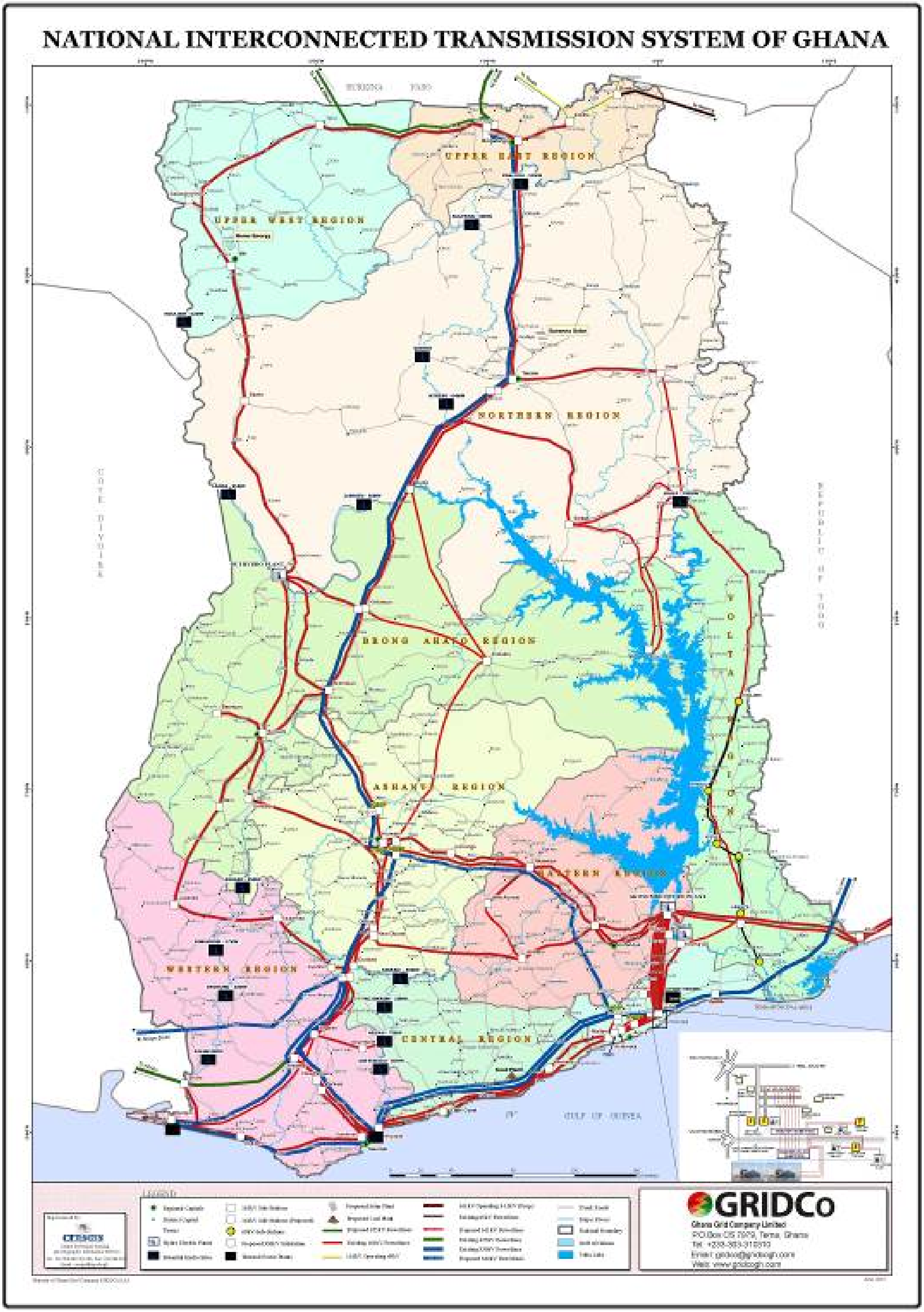
The second IPP, which was a 200-MW combined cycle power plant (Sunon Asogli, a Chinese Company), came on line in 2010. The Sunon Asogli plant has also been expanded by an additional 360-MW combined cycle plant, which was completed in 2017. At the end of 2017, the Ghana power system consisted of a number of hydropower and thermal plants owned by the VRA, Bui Power Authority (BPA), and six IPPs (TICo, Sunon Asogli, CENIT, AKSA, Karpowership and Ameri) with a total net dependable capacity of 3,971 MW as of December 2017, together with an embedded capacity of 167.5 MW (Trojan at a total of 115 MW; BXC Solar at 20 MW; Navrongo Solar at 2.5 MW; and Genser[12] at 30 MW).

[10] Energy Commission, National Energy Statistics 2000-2013, p 7. http://energycom.gov.gh/files/ENERGY%20STATISTICS_2014_FINAL.pdf

[11] Now TAQA after CMS sold off its interest in the venture in 2007.

[12] Genser supplies power to the Chirano mines.

Figure 5: Transmission System of Ghana



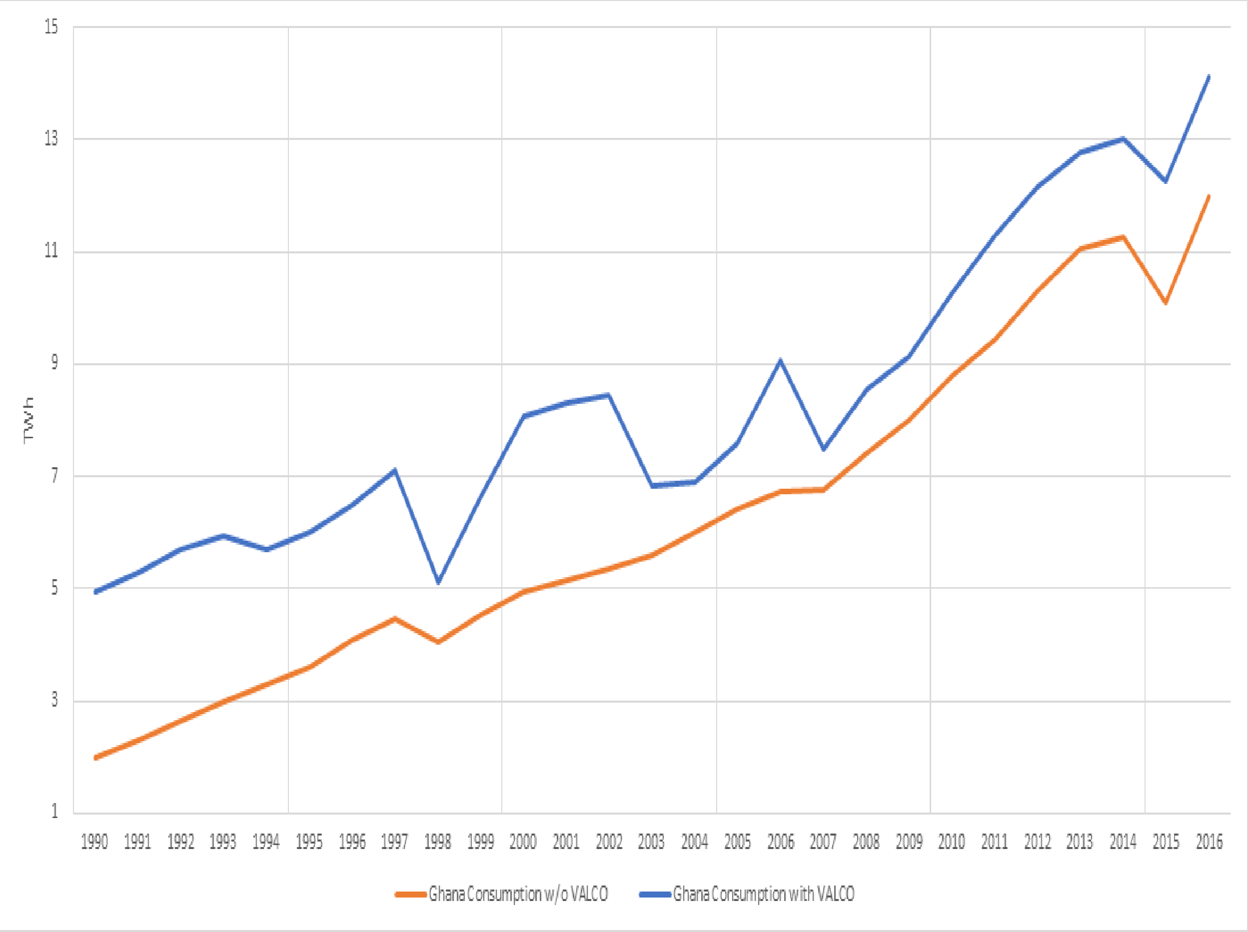
Source: GRIDCo, 2016.

By the end of December 2017, the country had three additional IPPs under construction: Cenpower, Amandi, and Early Power (which are expected to bring in up to 700 MW of additional capacity by end of 2019).

These generating units are evacuated through a transmission network with a total length of approximately 5200 km and with voltage levels spanning 69 kV (213 km), 161 kV (4950 km), 225 kV (73 km), and 330 kV (374 km) and terminating at 68 bulk supply substations (BSPs). The total transformer capacity, as of 2016, was approximately 5000 MVA. The national grid is interconnected with those of three neighbouring countries, Togo/Bénin (CEB), Cote d'Ivoire (CIE), and Burkina Faso (SONABEL) as shown in Figure 5.

Figure 6 shows how consumption of electricity in Ghana (with and without VALCO) has grown over the past 26 years. From 2007 to 2013, the growth rate for domestic demand was about 10%; however, this high growth rate was affected by supply challenges that hit the sector from 2013 to 2016. A key issue, therefore, is how the demand will grow in the future.

Figure 6: Historical Growth of Electricity Consumption in Ghana



Source: Energy Commission, VRA.

The distribution companies are ECG (which accounts for about 71% of the total electricity consumed annually), NEDCo (9%), and Enclave Power Company (EPC) (1%). Other bulk customers (some industrial customers, mining companies, hotels, etc.) consume 19% of the total energy transmitted.

ECG operates a network, which is approximately 20,000 km of 33 kV lines, 20,469 km of 11 kV lines, and 68,018 km of 415 V of distribution lines. NEDCo, on the other hand, operates 12,682 km of medium-voltage and 16,490 km of low-voltage network.

According to the GEDAP,[13] electricity access in the country as of the end of December 2018, has been estimated at a national average of about 84%.

2.1.1. Overview of Ghana Power Sector Institutions

The power sector in Ghana is under the sectoral/ministerial supervision of the Ministry of Energy. A key goal of the Ministry of Energy (MoEn) is to support the development of a reliable, high-quality energy service at the minimum cost to all sectors of the economy through the formulation, implementation, monitoring, and evaluation of energy sector policies.

The policies and programmes cover downstream and upstream petroleum subsectors and the power subsector (including renewable energy for power generation). MoEn is also responsible for the implementation of the National Electrification Scheme (NES), which seeks to ensure the provision of universal access to electricity for all communities in Ghana by 2020.

The electricity subsector in Ghana currently has an unbundled structure with separate entities having functional mandates over power generation, transmission, and distribution. The objective of this unbundled structure is to provide open and non-discriminatory access to transmission services to encourage private sector participation and market competition in the generation and distribution business functions. Power generation companies (GENCos) include the state-owned utilities (VRA and BPA) and a number of private IPPs. These IPPs have been licensed by the EC to build, own, and operate power plants, and sell their power to bulk customers or to distribution companies.

Fuel for power generation is on the whole procured by the GENCos themselves. Supplies of natural gas come from N-Gas of Nigeria, through the West African Gas Pipeline, and from the Ghana National Petroleum Corporation (GNPC) and the Ghana National Gas Company (GNGC). GNGC is currently the owner and operator of the gas processing plant in Atuabo and is the licensed natural gas transmission utility. GNPC is the national gas aggregator, and holds equity positions in the investments for natural gas development for the Government of Ghana. Fuel oil, light crude oil, and diesel come from a variety of suppliers contracted by the power plants.

Power distribution companies (DISCos) include the two state-owned utilities and Enclave Power Company, which is a private company that distributes power in the free zones enclave in Tema. The state-owned ECG (until March 2019) distributed electricity in the southern parts of the country,[14] and the Northern Electricity Distribution Company (NEDCo), a subsidiary of VRA, distributes electricity in the northern parts of Ghana.

The transmission function is performed by the Ghana Grid Company (GRIDCo), a state-owned entity, with the exclusive mandate to:

[13] Ghana Energy Development and Access Project – GEDAP.

[14] Effective March 1, 2019, Power Distribution Services (PDS) has taken over the power distribution functions of ECG under a 20-year concession agreement.

- Act as an independent system operator (ISO) and to provide non-discriminatory open-access to transmission services to all power market participants.
- Operate the NITS, which is made up of all electricity plants and equipment, within the borders of Ghana, that function or are operated at any voltage higher than 36 kV, as well as any associated feeder or supply equipment that are for shared or common use.
- Be the market administrator for the electricity market.

The operations and activities of all entities within the power sector are governed by contracts and electricity regulations. The provision of electricity services by the distribution utilities to both public and private consumers are subject to an independent regulator. There are two main electricity regulators in the sector:

The Public Utility Regulatory Commission (PURC), an independent body, was set up as a multi-sectoral regulator under the Public Utilities Regulatory Act, 1997 (Act 538) to regulate the provision of utility services in the electricity and water sectors, and by virtue of the Energy Commission Act, 1997 (Act 541), PURC also has regulatory responsibility over charges for natural gas supply (aggregated gas prices are processed by the aggregator, GNPC), transportation, and distribution (gas transportation pipeline tariff) of natural gas services.

The EC, which was set up in 1997 under the Energy Commission Act, 1997 (Act 541) to regulate and manage the development and utilisation of energy resources in Ghana as well as to provide the legal, regulatory, and supervisory framework for all providers of energy in the country. The EC under Section 2.2(c) of Act 541 is mandated to “prepare, review and update periodically indicative national plans to ensure that all reasonable demands for energy are met”. The Act also mandates the EC to grant licences for the construction and operation of all transmission, wholesale electricity supply and distribution assets within the sector, and to enforce performance standards (technical and operational rules of practice) of the utilities. The EC also grants licences for natural gas and related matters.[15]

2.1.2. Market Framework

Currently, there are two markets in Ghana:

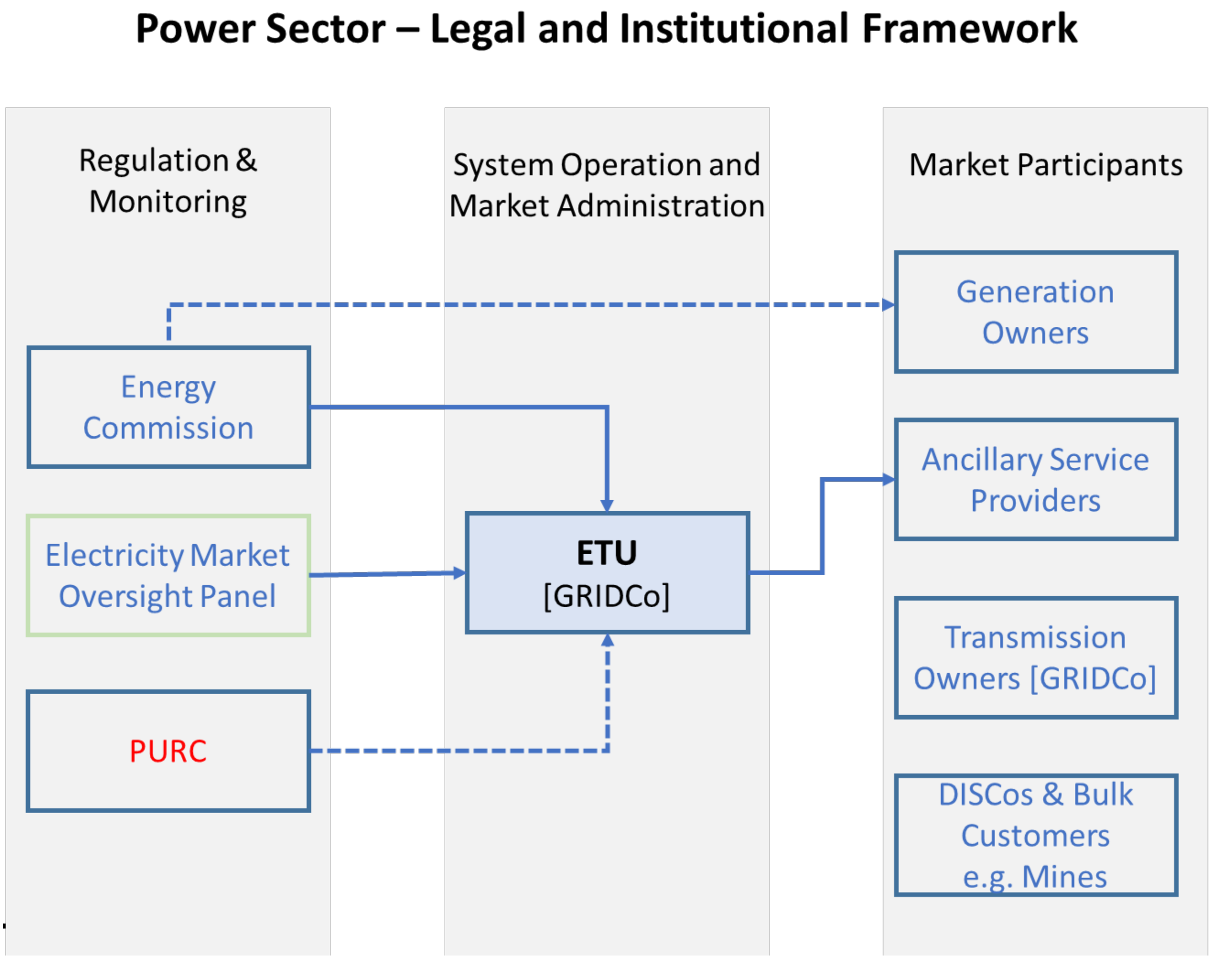
- Deregulated market where “bulk customers” procure electricity from the grid at their own negotiated prices with the generators; and
- Regulated market where distribution utilities supply electricity to consumers at regulated prices approved by the PURC.

Figure 7 illustrates the market and regulatory framework governing the power sector. The EC, PURC, and the Electricity Market Oversight Panel (EMOP) carry out technical, financial, and market regulatory, and monitoring functions over the generating companies, GRIDCo, distribution companies, and bulk customers.

The ancillary services market also ideally will be established under the wholesale electricity market (WEM) and governed by the same regulators.

[15] EC Act 541 (sections 25 to 29) and LI 1911.

Figure 7: Institutional Relationships



2.1.

Table 1 lists the various legislative instruments that guide the operation of the Ghana power sector. The objectives, purpose, and scope of each legislative instrument are also stated. While the instruments noted here are not exhaustive, these are the key ones that impact the development of the IPSMP.

Table 1: Key Legislations for Ghana Electricity Sector

Regulation/ Legislative Instrument	Reference Number	Summary of Objectives, Purpose/ Scope
Electricity Transmission (Technical, Operational, and Standards of Performance) Rules, 2008	LI 1934	These rules define NITS and establish the requirements, procedures, practices, and standards that govern the development, operation, maintenance, and use of the high-voltage NITS. These rules shall apply to the Electricity Transmission Utility (ETU) and persons connected to the transmission system including: (a) Wholesale electricity suppliers licensed by the Commission, (b) Electricity distribution utilities licensed by the Commission, and (c) Bulk customers of electricity duly authorised by the Commission.

Regulation/ Legislative Instrument	Reference Number	Summary of Objectives, Purpose/ Scope
		The Electricity Transmission Utility (ETU), as the independent operator of the transmission system, is not a grid participant. A grid participant is a person who has a valid connection agreement (CA) with the ETU to: (a) Construct, own, and connect a facility to the transmission system infrastructure; (b) Inject, wheel, or off-take power for its own use or for retail; (c) Provide ancillary services; or (d) Exchange power either with the electricity networks of neighbouring countries or within the West African Power Pool.
Electricity Supply and Distribution (Standards of Performance)	LI 1935	The regulations apply to electricity supply and distribution utilities licensed by the Commission. These regulations define the "electricity supply and distribution utility" as a person licensed under the Act to distribute and sell electricity without discrimination to consumers in an area or zone designated by the Commission. The regulations also provide performance benchmarks for electricity supply and distribution in conformity with the provisions of Electricity Supply and Distribution (Technical and Operational) Rules, 2005 (LI 1816).
Electricity Regulations	LI 1937	These regulations provide guidance to the planning, expansion, safety criteria, reliability and cost-effectiveness of the NITS, regulate the WEM, the technical operations of the ETU; define the minimum standards and procedures for the construction and maintenance of facilities and installations; the protection of electrical installations and services; life, property and the general safety of the public in respect of electricity services; define the minimum reserve margins to satisfy demand and the development and implementation of programmes for the conservation of electricity.
Electricity Supply and Distribution (Technical and Operational) Rules, 2005	LI 1816	These rules provide technical and operational guidance for services in the standard voltage range of 230 V – 34.5 kV. The guidance is provided under five main technical and operational areas of: ▪ Supply and Metering of Electricity (Rules 1 – 7) ▪ Quality of Supply of Electricity (Rules 8 – 14) ▪ Electricity Interruption (Rules 15 – 19) ▪ Electricity Billing (Rules 20 – 22) ▪ Bill Payment (Rules 23 – 44)
National Electricity Grid Code of Ghana, 2009		The purpose and scope of the National Electricity Grid Code is to ensure the coordinated operation of the high-voltage NITS within Ghana, for the provision of fair, transparent, non-discriminatory, safe, reliable, secure, and cost-efficient delivery of electrical energy. It establishes the requirements, procedures, practices, and standards that govern the development, operation, maintenance, and use of the high-voltage transmission system in Ghana. The Grid Code describes the responsibilities and obligations

Regulation/ Legislative Instrument	Reference Number	Summary of Objectives, Purpose/ Scope
		associated with all the functions involved in the supply, transmission, and delivery of bulk electric power and energy over the NITS, including the functions of the ETU, a NITS asset owner, a wholesale supplier, a distribution company, and a bulk customer.
Renewable Energy Act, 2011 (Act 832)	ACT 832	The purpose for this regulation is to provide for the development, management and utilisation of renewable energy sources for the production of heat and power in an efficient and environmentally sustainable manner and to attract investment in renewable energy sources.
Public Utilities Regulatory Commission	ACT 538	This Act provides for the establishment of a PURC to regulate and oversee the provision of utility services by public utilities to consumers and to provide for related matters. The functions of the PURC include, among others: ▪ Develop guidelines on rates chargeable for provision of utility services; ▪ Examine and approve rates chargeable for provision of utility services; ▪ Protect the interest of consumers and providers of utility services; ▪ Monitor standards of performance for provision of services, and conduct investigations on quality of service; and ▪ Promote fair competition among public utilities.
Energy Commission	ACT 541	This Act establishes an Energy Commission and defines its functions relating to the regulation, management, development and utilisation of energy resources in Ghana. The primary objective of the Energy Commission is to regulate and manage the utilisation of energy resources in Ghana and coordinate policies in relation to them. The functions of the Energy Commission include, among others: ▪ Recommend national policies for the development and utilisation of indigenous energy resources; ▪ Advise the minister on national policies for the efficient, economical, and safe supply of electricity, natural gas, and petroleum products having due regard to the national economy; ▪ Prepare, review, and update periodically indicative national plans to ensure that all reasonable demands for energy are met; ▪ Secure a comprehensive data base for national decision-making on the extent of development and utilisation of energy resources available to the nation; ▪ Receive and assess applications, and grant licences to public utilities for the transmission, wholesale supply, distribution, and sale of electricity and natural gas; and ▪ Establish and enforce, in consultation with PURC, standards of performance for public utilities engaged in the transmission, wholesale supply, distribution and sale of electricity and natural gas.

3. Electricity Planning Process

3.1. Historical Planning Process

Planning for electricity demand and supply in Ghana was at a very limited scale when ECG operated isolated diesel plants in some of the major towns in Ghana. In 1965, when VRA started the operation of the hydropower generation station at Akosombo, VALCO constituted about 70% of the demand on the grid. Since then, a "system wide" national power and energy demand and supply planning process began in Ghana, led by VRA.

The VRA national planning activity covered several different time horizons including a) annual (12-month operational plans), b) short term (three-year look ahead), and c) long term (five to 10 years and beyond). As part of its planning mandate, VRA carried out load forecast exercises over time to determine the peak demand and energy requirements of its customers. The supply planning process at VRA depended on simple and fairly standard spreadsheets (developed in-house) and a scenario analysis model (VRASim developed by VRA together with ACRES International). The main planning objective was, essentially, to ensure availability of sufficient power and energy to meet the demand from VALCO's running alumina smelting potlines and their auxiliaries, as well as the domestic and mine loads, with a planned reserve margin. The total national demand, therefore, depended on inputs from annual projected specific operational requirements from VALCO, ECG (for domestic demand), and some existing mines.

It was necessary to manage the Akosombo Dam reservoir for power production to minimise water spillage in years of good rainfall and to efficiently draft the reservoir within its "maximum" and "minimum" limits to avoid over-drafting in years of drought. Balancing the power supply to match the aggregate loads of VALCO, ECG, and the bulk customers was based on the hydrological situation that was jointly assessed by VRA and VALCO.

In 1972, the last two units of Akosombo plant (Units 5 & 6) were commissioned into service to meet the expected demand growth (following completion of all six VALCO alumina smelting potlines).

In 1974, ACRES International and Shawinigan Engineering Company Limited were commissioned by the Canadian International Development Agency (CIDA) to undertake a study, on behalf of VRA, to determine a generation expansion programme for Ghana. The scope of work included a comprehensive study for the Kpong hydropower project. The study commenced in June 1974 and the final report was presented in July 1975. As part of the implementation of the study recommendations, the contract for the execution of the Kpong project was awarded to Impregilo-Recchi Joint Venture and site works commenced in November 1977. The project was completed by December 1981.

Ghana continued to have adequate generation from hydropower sources and was even able to export power to neighbouring countries until it experienced its first power crisis in 1983/1984, following the global drought situation in the early 1980s.

The second Generation and Transmission Master Plan study was initiated by VRA to examine the options for thermal complementation to the country's hydropower system. This study was completed in 1985 by ACRES International Ltd. on behalf of VRA. A key recommendation from this study was to introduce thermal generation to complement hydropower generation. The recommendation for additional capacity was not implemented until 1996 when the construction of the 330-MW Takoradi Thermal Power Plant (TAPCo) began, and the commissioning into service of the first gas turbine unit in December 1997.

By the late 1990s, VRA initiated another Generation and Transmission System Master Plan Study to update the 1985 Generation and Transmission System Master Plan Study. This update study was completed in 2001 by ACRES International (now Hatch Ltd.), and it had the broad objective to “review, evaluate, define and rank all available generation options and establish the optimum generation and transmission system expansion programme needed to meet the forecast demand of VRA’s customers in a least-cost manner”.

In 1997, Energy Commission (EC) was established and was mandated under Act 541, Section 2.2(c) to “prepare, review and update periodically indicative national plans to ensure that all reasonable demands for energy are met”. In an effort to fulfil its mandate, the first long-term integrated sustainable energy plan called the Strategic National Energy Plan (SNEP) was initiated by the EC in 2000, but the actual report was published in 2006. The focus of SNEP study was over the medium to long term (15 years and beyond). The study not only covered the power sector and expansion of existing power facilities, but also petroleum (oil and gas), renewables, biomass/ wood fuels/traditional fuels, while considering technology diversification, socio-economic and environmental issues, and energy efficiency and conservation measures.

Following the SNEP report in 2006, the VRA in April 2009 commissioned the “VRA Situation Report”[16] by Synexus Global (a subsidiary company of Hatch Ltd.), with the following goals:

(a) To review the most recent generation plan;

(b) To collect relevant generating plant characteristics and operations data;

(c) To review the current operating policies to establish deficiencies in the current operating strategy in meeting the stated policy objectives; and

(d) To provide a solution to implement the recommended strategy.

This study was focused on VRA’s operations and planning in particular, and Synexus Global prepared an indicative generation and transmission plan, using its Vista suite of modules as an operational tool for implementing the recommended strategy (Hatch Ltd., 2009). In the same year of 2009, Synexus Global, at VRA’s behest, undertook a second study[17] with the objective to provide a “planning analyses report which establishes an indicative 20-year schedule of generating plant additions and associated transmission facilities that will ensure secure and reliable delivery of power and energy to the Ghanaian power system at the least present worth cost”.

Soon thereafter, in 2011, GRIDCo undertook a Generation Master Plan study, which was preceded by a Transmission Master Plan for GRIDCo’s transmission planning activities. These studies for GRIDCo were mostly focused on demand forecast at each of the bulk supply points, and generation and transmission expansions needed to meet the expected

[16] “VRA Situation Report”, Hatch Ltd., doing business as Synexus Global – April 15, 2009.

[17] “Generation Strategy Study for the Akosombo and Kpong Generation Stations – Indicative Generation Expansion and Transmission Planning Review”, Hatch Ltd., doing business as Synexus Global – June 5, 2009.

demand forecast. In 2014, VRA conducted a demand forecast study to support their planned expansion activities. Most recently in 2016, USAID contracted Nexant Inc. to develop demand forecasts for the country, considering the potential suppressed demand that exists in Ghana due to technical and economic constraints, including lack of reliable power supply during the *Dumsor* ("on and off") period.

Thus, Ghana has had a strong history of developing plans for expanding the electricity subsector. However, with the separation of generation subsector from transmission and distribution (as called for by the Power Sector Reforms), several different modelling tools for planning studies have been employed, depending on which consultants were contracted and whether they fully conducted or supported a particular study.

These different plans and demand forecasts, more often than not, were not coordinated and did not complement each other, owing to the use of different data sets, different and uncoordinated internal planning assumptions and expectations, and different planning methodologies employed. Further, the inability to finance the construction of the required power projects hindered the timely and effective implementation of planning study recommendations.

3.1.1. Institutional Roles in the Current Planning Process

In this section, the institutional roles of the various agencies in the power planning process are described, along with some of the challenges that need to be addressed in the future. In general, while most of the institutions do short-, medium-, and long-term planning, the planning work is conducted in "silos", thereby denying the sector the synergy that a joint or more collaborative planning team (such as a consensus-based demand) can achieve. Worse still is the lack of accountability regarding which institution is ultimately responsible for ensuring that the sufficient capacity of the "right" type of generation is procured that will avoid any power shortages or overcapacity situations.

Ministry of Energy

The Ministry of Energy (MoEn) is mainly a policy-making institution that formulates, monitors and evaluates energy sector policies to ensure that reliable and high-quality energy services are provided at the minimum cost to all sectors of the economy. MoEn therefore sets the strategic agenda for all of the players in the energy sector and currently plays other roles in addition to policy formulation, as noted below:

- MoEn oversees the implementation of the Rural Electrification Policy/Programme (REP), as part of the National Electrification Scheme (NES), which is meant to work progressively towards achieving the goal of universal access to electricity by 2020.[18] The process of the implementation of the REP, however, tends to be influenced by the political expediency of supplying power to vocal un-electrified communities in politically marginal constituencies. This often leads to some communities being connected out of turn or not according to plan, leading to agitations by communities who are bypassed.
- To support procurement and construction of power plants, MoEn has collaborated with the Ministry of Finance to facilitate the provision of Government Consent and Support Agreement (GCSA) (at the request of IPPs as part of their financial risk mitigation

[18] Universal Access is defined as when 90% of the population has access to electricity.

instruments) under generation expansion arrangements. The GCSA has recently been replaced with a put-call-option agreement (PCOA) to help investors in power plants to mitigate a part of their financial risks (e.g., pre-mature project contract termination).

- In the past, when MoEn perceived an impending shortage of power supply capacity, arrangements were put in place by MoEn to directly negotiate and procure emergency power plants as short-term measures to address the anticipated generation capacity deficit. Unfortunately, the procurement of such emergency power plants was from unsolicited proposals from investors rather than a competitive bidding process. The procurement process in such cases was often not transparent, with non-competitive pricing, which has often led to higher than optimum tariffs for the final consumer. The negotiated PPAs were also signed for long-term period beyond the emergency periods.
- MoEn is often the primary point of contact for development partners who are seeking to provide technical, financial, or any other type of support to the power sector agencies in Ghana.

Energy Commission

Based on its mandate, as stipulated by the Energy Commission Act, 1997 (Act 541), the functions of the EC include the following:

- To license operators in the generation, transmission and distribution of electricity and natural gas.
- To serve as the Government's **energy policy adviser** by making **national energy policy recommendations** to the Minister of Energy.
- To prepare, review, and update periodically indicative national plans to ensure that all reasonable demands for energy are met.
- To secure a **comprehensive database** for national decision-making for the efficient development and utilisation of energy resources.

In an effort to fulfil its planning mandate, the EC undertook an energy planning study in 2000, and produced the SNEP 2006–2020, which is currently being updated. The EC is also the focal institution for the development this IPSMP, given that it is a subset of SNEP.

The EC also collates data on energy and other allied sectors, and publishes this information annually as the National Energy Statistics Bulletin, which provides informative and helpful inputs into energy planning activities. The EC also undertakes and supports specific surveys to collect the necessary data for SNEP.

GRIDCo

The planning role of GRIDCo is stipulated in the Electricity Regulations, 2008 (LI 1937), Section 11.1, which requires that the transmission utility "shall plan and operate the National Interconnected Transmission System (NITS) in a safe, reliable and transparent manner and in accordance with the provisions of the National Electricity Grid Code".

Thus, GRIDCo, in collaboration with other stakeholders (EC, VRA, ECG, NEDCo, BPA) prepares the Annual Supply Plan with a short- to medium-term outlook on supply-demand balance.[19] Bulk customers and distribution companies (DISCos) also provide inputs into the

[19] See GRIDCo, Electricity Supply Plan: http://www.gridcogh.com/en/publications/electricity-supply-plan.php (accessed May 9, 2018).

electricity demand forecast while generating companies (GENCos) provide input into the strategic use of various generating resources to adequately meet the projected demand.

GRIDCo also undertakes transmission planning analyses for potential projects to support integration of these projects to the national grid. As needed, GRIDCo also commissions transmission master plan studies to support its transmission expansion plans for the short to medium term.

DISCos

The individual distribution companies (DISCos) carry out their own load demand forecasts to determine the levels of electricity demand in their areas of operation for the ensuing year, which serve as inputs into the Annual Supply Plan (see above).

Additionally, the DISCos also carry out loss reduction studies to help reduce the distribution losses while ensuring that overloaded distribution facilities/infrastructure like distribution lines and transformers, as well as switchgears, are upgraded as necessary. The DISCos also carry out studies to determine suitable locations and capacities for grid integration of variable renewable energy projects. The studies also take into consideration the technical and financial challenges that arise as a result of integrating variable renewable energy projects into the network and the resultant impacts on the financial health of the distribution utilities.

As needed, the DISCos also commission studies for a distribution master plan to support their network expansion, based on anticipated load growth. For example, ECG commissioned a study on its network expansion plans in 2008, supported by the Japan International Cooperation Agency (JICA).

VRA and IPPs

VRA and the other generating companies (IPPs) provide information to the Annual Supply Plans on the availability of their various generating resources to meet the projected demand, based on their maintenance schedules. As needed, VRA and the IPPs also carry out planning studies to determine what opportunities exist in the power market to increase their portfolio and market share.

With the passage and implementation of the renewable energy law and the obligations under the renewable energy purchase obligation (REPO), new windows of opportunity are open to these entities in meeting Ghana’s renewable energy commitments.

PURC

PURC determines various tariffs (bulk supply tariff [BST], transmission service charge [TSC], distribution service charge [DSC], etc.) that will enable the generating, transmission, and distribution companies to recover their reasonable cost of investment while not overcharging the consuming public. As part of the process of determining the appropriate tariffs for market participants in the regulated market, PURC reviews tariff review proposals from the GENCos, GRIDCo, and the distribution companies (ECG, NEDCo, and EPC) and carries out stakeholder engagements to take on board the views of the producers, transporters, distributors, and consumers of electricity in setting the final tariff.

Bulk Customers

Bulk customers, including VALCO and the mines, constitute a significant segment of the consumers. These entities are in the deregulated market, but their expansion or down-sizing plans can affect the demand forecast as a whole, in terms of national level planning.

Currently, the bulk customers provide their suppliers (GENCos) with their annual demand forecast and expansion plans for incorporation into the aggregate demand projections.

GNPC and GNGC

The Ghana National Petroleum Corporation (GNPC) is Ghana's National Oil Company (NOC), established in 1983 by PNDC Law 64 to support the government's objective of providing adequate and reliable supply of petroleum products and reducing the country's dependence on crude oil imports through the development of the country's own petroleum resources.

GNPC's mandate is to undertake the exploration, development, production, and disposal of petroleum resources.

In July 2011, some of the gas operations of GNPC were ceded to Ghana National Gas Company (GNGC), whose role as a gas service company in power sector planning is to provide information on current and future gas infrastructure required for gathering, processing, and delivering natural gas to customers such as power plants. GNGC will take annual gas requirements from the GENCos and provide inputs on the gas availabilities they can support.

GNGC has been licensed under the Energy Commission Act as the national gas transmission utility to operate the National Interconnected Gas Transmission System. GNGC also owns and operates the gas processing plant that process the raw gas from Jubilee and TEN fields into lean gas and other related products.

4. Planning Context in Ghana Power Sector

4.1. Historical Challenges

Over the last 35 years, Ghana has experienced a number of periods of power supply shortfall (e.g., in 1983/84, 1997/98, and 2006/07), which resulted in nationwide power rationing and serious "brown-outs" that have had adverse impacts on the economy. The most recent crisis of such a generation shortfall (christened as *Dumsor*, meaning "on and off" in the local Akan language) spanned continually from 2012 to 2015. Industries, households, and government works were adversely affected by these power disruptions, which negatively impacted the Ghanaian economy.

Three major factors, among others, contributed to the 2012-2015 power supply crisis:

- The 2012 accidental rupturing of the West African Gas Pipeline (WAGP) along the Togo/Benin segment (a fuel insecurity risk factor),
- Over-drafting of hydropower reservoirs resulting in significant reduction in Akosombo Dam Reservoir levels,
- Cash flow constraints in the power sector, and
- Lack of adequate and timely investments in the sector.

These factors are described below to illustrate the context for the development of this IPSMP.

4.1.1. Accidental Rupturing of the WAGP

On August 27, 2012, WAGP was severely ruptured along the Togo/Benin segment of the underwater gas pipeline by the anchor of a vessel. This accident completely shut-off gas supply from Nigeria to Ghana, Togo, and Bénin, which resulted in major power supply problems to Ghana. Thermal power plants at Aboadze and Tema were severely affected with the "gas-only-fired" plants located in Tema (200 MW Sunon Asogli, 45 MW TT2PP, 80 MW Mines Reserve Plant, etc.) being shut down completely. This created a need to shed some load from the grid, due to the system's inability to meet scheduled load or demand.

The gas pipeline was repaired and returned to service in June 2013; however, the expected contractual gas volumes could not be delivered by WAGP for a number of reasons.

4.1.2. Over-Drafting of Hydropower Reservoirs

The loss of thermal generation capacity resulting from the forced shutdown of gas-only-fired plants in Tema (due to the loss of supply of natural gas) and the shutdown of some plants in Takoradi (due to technical challenges) led to the over-drafting of the Akosmbo Dam reservoir. In the period between 2012 and 2014, generation from hydropower sources was above the recommended level of generation from this source.

The plants that were shut down in Takoradi included:

- T3 – due to operational challenges
- TAPCo (T1) – half of the combined cycle plant capacity was lost to equipment grounding challenges
- TICo (T2) – half of the TICo plant was shut down to add a steam portion and upgrade to combined cycle plant

Neither the loss of the gas supply from Nigeria, nor the technical problems that occurred in the Takoradi power plants were anticipated to last for as long as they did. Consequently, the “conscious over-drafting” of the reservoir, that was used to mitigate the impact of the loss of thermal generation, led to very low levels of water in the reservoir, which subsequently became the cause of generation capacity shortfalls in 2014-2015.

4.1.3. Cash Flow Constraints in the Power Sector

Cash flow constraints have plagued the power sector ever since thermal power was introduced into the generation mix. The increased cost of thermal generation as compared to the cost of hydropower generation from Akosombo and Kpong, was not fully passed on to consumers as it arose. Additionally, the distribution losses incurred by the DISCos remained high, inspite of many attempts to tackle both technical and commercial losses.

These cash flow challenges have caused delays in securing letters of credits (LCs) for the payment for fuel (light crude oil, distillate fuel oil, natural gas, etc.) and lubricant imports for electricity generation following the introduction of thermal plants into the generation mix.

The supply of gas from Nigeria was designed to reduce the cost of thermal generation in the country, by substituting the use of light crude oil as generation fuel, with the relatively cheaper natural gas. The required volumes of gas, however, never fully materialized, and the rupture of the WAGP in 2012 dealt a major blow to an already precarious financial situation.

VRA had to raise additional funds in excess of their annual fuel budget to procure light crude oil to run plants both in Tema and Aboadze at a huge extra cost to the utility and to the economy of Ghana. This is because the VRA operational plans and the tariffs approved by PURC to recover these costs were based on operating the power plants mainly on natural gas, and the tariffs were not adjusted by the PURC to reflect the increased cost of generation.

To date, the financial impact of the 2012 gas supply disruption and the limited supply of gas volumes to Ghana from Nigeria are still being felt in the power sector.

4.1.4. Lack of Adequate and Timely Investment

From the 1960s to even as late as the early 2000s, much of the investment in the power sector was driven by public sector investments (by the Government of Ghana), mainly in the form of foreign multi-lateral and bilateral loans, grants and a small proportion of private capital. Therefore, one of the greatest challenges facing the country’s energy sector over the last 2 decades was the availability of capital for investment in electricity infrastructure delivery, maintenance, expansions, and upgrading of facilities. For example, the sector needed huge and timely investments to:

- Upgrade the capacity of electricity generation to match demand,
- Complete the overhaul of the aged and obsolete distribution network, and
- Upgrade and remove bottlenecks in some segments of the transmission network.

However, as the country’s economy and population expanded, the Government of Ghana needed to invest its limited capital in a number of different sectors, and securing adequate and timely funding for investments in the energy sector became difficult. Limited budgets and poor balance sheets of the utilities also did not allow for sufficient investments in new power plants and fuel procurement as thermal generation became a larger share of the generation mix. Hence, dwindling investments in the power sector resulted, in part, to delayed implementation of capacity expansions, as per the planning study recommendations.

These same funding challenges ultimately contributed to power shortages encountered during some of the previous “power rationing” periods (e.g., in 1998, and 2007).

The effects of the funding challenges were not just limited to the inability to develop new generation capacity, but it also resulted in delays in the timely upgrade of simple cycle plants to combined cycle plants.

A good example of the funding challenges is the development of the Bui hydropower plant, which was identified as a technical and economic option in the late 1960s. There were a number of feasibility studies undertaken from 1966 to 2006,[20] with no decision made to implement the project because of the nation’s inability to secure funding for its construction. Hence, the project remained on the drawing board until 2007 when a Chinese loan was secured to undertake the construction of the plant, which was completed in 2013.

4.1.5. Perils of Emergency Procurements

The periods during which Ghana experienced power shortages were termed as “emergency periods” and the Government of Ghana in its efforts to quickly bring on line new power plants, responded to a number of unsolicited proposals and procured short-term emergency power plants. During the 1997/98 power crisis for example, 30-MW mobile diesel generators were procured from Aggreko and another 32-MW mobile diesel generators from Cummins for 2 years.

The recent power crisis (2012–2016) precipitated the procurement of emergency power plants such as the aero-derivative mobile power plants from Ameri and rented/leased HFO-fuelled plants from Karpowership. Procuring or renting such “emergency power plants” over short rental periods tend to result in high end-user tariffs, and in an attempt to mitigate the cost of the emergency plants, they were contracted on a long-term basis – thus spreading the costs over a longer period. There was, however, no assessment of the impact of the extension of these emergency procurements on the longer term supply-demand balance, bearing in mind that other long term power projects were being negotiated at the same time.

This uncoordinated emergency procurement of power plants led to an over procurement of power projects. Subsequent analysis of the supply-demand outlook clearly indicated that the country was over-committed to power projects. There was, however, some delay and

[20] The first detailed studies were conducted by J. S. Zhuk Hydroprojeckt of USSR in 1966. Another feasibility study was undertaken in 1976 by Snowy Mountains Eng. Corp (SMEC) of Australia, followed by yet another feasibility study undertaken in 1995 by Coyne et Bellier of France. This 1995 study was subsequently updated in 2006 to establish that the 400-MW Bui hydropower scheme was the most technically and economically attractive option after the Akosombo and Kpong hydropower plants.

reluctance to curb the commitment to power projects, and the lack of a clear and unambiguous power sector plan somewhat contributed to the delay in action being taken.[21]

There has been a view in the power sector that says that tariff cannot be increased during a period of unreliable power supply, such as the outages during a power shortage. As such, throughout the power crisis, tariffs remained unchanged. However, once the capacity shortage was eliminated through the procurement of emergency power, the tariffs were raised to reflect both the depreciated value of the local currency and the increased generation costs (partly due to the expensive emergency power purchase contracts that had been entered into).

The higher tariffs combined with the relatively low post-2014 diesel fuel prices resulted in a reduction in the consumption of grid-based electricity. This “demand suppression” occurred because electricity generation from diesel gen-sets was cheaper than paying for grid-based electricity. The *Dumsor* or unreliable nature of supply from grid-based electricity from 2012 to 2016 also led consumers to view captive generation as being more reliable (in terms of industries having more control over their planned operations) than electricity supplied from the grid.

4.2. CURRENT PLANNING CHALLENGES

Currently, Ghana’s power sector is affected by a number of key risks and uncertainties both in the short and the long term. In this section, each of these elements are described, along with an indication of how they impact both short- and long-term planning. These issues also inform the planning environment that has driven the development of this IPSMP.

These risks and uncertainties have been addressed through sensitivity analyses conducted in the modelling framework for the IPSMP.

4.2.1. 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:

- Uncertainty of industrial and commercial demand uptake, as industries and large commercial customers are more willing to switch to alternative options (e.g., cheaper diesel generators, solar photovoltaics [PVs]) due to the high tariffs charged to non-residential customers;
- Increasing potential for residential and commercial customers to invest in self-generation through solar PV systems and diesel generators;
- 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

[21] Although the SNEP existed, many PPAs were executed, committing the country to excess capacity at high tariffs.

- Lack 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.

In addition, demand forecasts by sector agencies in Ghana have tended to use different assumptions and methodologies, which result in a range of indicative forecasts being used by different institutions for their own planning initiatives. For example, the EC's indicative demand forecast, which uses bottom-up methodology and end-use survey data, projects "potential demand", i.e., the demand if techno-economic constraints are removed. The regression analysis used by VRA, ECG, and NEDCo, on the other hand, evaluates actual "realised demand". Furthermore, even with the common approach of VRA, ECG, and NEDCo, their use of different explanatory variables and different timeframes lead them to produce differing forecasts.

In general, not using an authoritative and accepted "base case" demand forecast for procurement decisions has contributed to the current overcapacity situation in Ghana, in which the installed and available capacity are much higher than the peak demand. For example, the peak demand in 2017 was 2,193 MW, whereas the installed capacity at the end of 2017 was 4,272 MW. The net dependable capacity (i.e., considering fuel and maintenance limitations) was much lower (3,971 MW as of December 2017) than the above-stated installed capacity.

Economic growth is a key driver of demand forecasts, and currently, most forecasts rely on the Ministry of Finance's short-term forecasts and the IMF's short- to medium-term forecasts. In the longer term (10–20 years), forecasts are usually based on political/policy expectations from the National Development and Planning Commission (NDPC) or just moving averages from IMF forecasts. In general, a business-as-usual expectation is that the long-term annual average of the real GDP growth will average around 6.5%. Electricity demand growth is then determined from the elasticity between GDP growth and electricity demand growth. However, the elasticity of electricity consumption to GDP growth itself could be changing over time due to changes in economic growth drivers (e.g., contribution of service sector to GDP relative to agriculture and industrial/mining sectors) and due to energy efficiency and DSM.

Increasing average daily temperatures 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 than 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.

Therefore, whether the country can achieve better monitoring and forecasting of demand growth for electricity remains a key uncertainty for planning in Ghana's power sector. To address these issues, three different forecasts (i.e., reference, high, and low cases) are considered in the IPSMP's sensitivity analyses.

4.2.2. Energy Efficiency and Demand-Side Management

Energy efficiency and conservation practices have been promoted in Ghana since the 1980s, and have contributed significantly to managing demand growth. These practices, in addition to voluntary DSM options such as reducing peak load and utilisation of self-generation, offer Ghana a strong potential to save and reduce its energy consumption and peak demand. The Energy Foundation and the EC in recent times have undertaken several programmes to promote energy efficiency and conservation measures, such as rating and labelling of appliances.

Recent audits of various commercial buildings in Accra suggest that up to 10–30% of energy use 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.

Energy efficiency and conservation measures therefore, can reduce the rate of growth of demand for electricity, while DSM can reduce the need for additional generation to meet peak demand. From a planning perspective, it is important to measure and track the impact of energy efficiency and DSM activities (e.g., the resulting effect of an exchange of 6 million compact fluorescent lamps (CFL) bulbs for in-use incandescent bulbs and a ban of incandescent light bulbs saved about 124 MW capacity for the country) and include this impact in the demand forecasts, so that the generation capacity requirements are not overestimated. It is estimated by the Energy Commission that 400 GWh was saved due to the efficient refrigeration programme in 2015.

4.2.3. Supply-Side Issues

The supply-side options associated with Ghana's power system—made up of 57.8% thermal power, 41% hydro, and 0.6% renewable energy as at December 2016—are enumerated as below.

Water Availability for Hydropower Generation

The hydrology or inflows of the various tributaries of the Volta River provide key indicators for the availability of water for hydropower generation. The water level in the Akosombo Dam has been low in recent times mainly due to drafting of the reservoir beyond the recommended levels of generation from these hydropower sources. The over-drafting was mainly due to shortfalls in thermal generation because of unreliable gas supply, as discussed earlier.

Furthermore, changes in inflows due to climate change could further exacerbate the risks of water availability for hydropower generation

Natural Gas Resource and Infrastructure Constraints

The country's natural gas supply depends on only two sources of supply: (i) imported natural gas from Nigeria through the WAGP, which supplies mainly power plants in the Tema power enclave (it accounted for about 14.4% of the total volume of natural gas supplied in 2016); and (ii) indigenous gas supply[22] which accounted for about 85.6% of the total natural gas supplied in 2016. The indigenous gas is processed at Atuabo Gas Processing Plant before being transported to the power plants in the Takoradi/Aboadze enclave. Gas from the OCTP/Sankofa field is expected to add 140-180 MMCFD to the indigenous gas supply from October 2018 onwards.

The WAGP is currently configured to allow for unidirectional gas flow only from the Tema power enclave in the east to the Takoradi/Aboadze power enclave in the west. In an effort to

[22] Indigenous gas production in 2016 was only rom the Jubilee and TEN fields.

provide additional supply options for power plants in Tema, GNGC is expected to make investments that allow for reverse flow of gas from the west to the east. This system of reverse gas flow is expected to balance gas supply requirements for power generation, especially when Sankofa gas production will increase the indigenous supply in the west.

The reverse gas flow is currently the only option to effectively use at least 90% of gas production from the Sankofa fields under the "take-or-pay" contractual agreement.[23] At present, nearly all of the gas produced must be utilised by the power sector. Furthermore, the "reverse flow" path also offers opportunities for gas from associated gas fields (Jubilee and TEN) to be consumed, as there are no storage options available. An onshore West-to-East gas pipeline is also planned to link the western gas supply with the eastern power enclave.

Natural gas supply volumes from Nigeria through the WAGP have been unreliable, irregular, and below contractual volumes since 2012 for a number of reasons: (i) damage to the gas pipeline by a ship's anchor at Togo, which disrupted gas supply to Ghana for almost a year; (ii) gas supply challenges from the Niger Delta region due to unfavourable upstream investment climate; (iii) persistent sabotage of natural gas transportation pipeline (i.e., the Escravos Lagos Pipeline System); and (iv) challenges with timely payment for gas already supplied/consumed by VRA. Therefore, the dual-fired power plants in the Tema power enclave resort to the use of relatively more expensive light crude oil (LCO) or diesel to operate, while the gas-only-fired plants remain idle.

Similarly, when natural gas supply from Atuabo is cut off due to challenges with its compressor system or the FPSO, the power plants in Aboadze are also forced to use more expensive LCO to operate or shut down. The repeated switching from gas to LCO or vice versa has its own challenges or risks (e.g., "coking" of fuel nozzles), which can lead to higher maintenance costs and capacity shortfall risks.

In addition, gas availability in the Middle-Belt and NEDCo regions (through pipeline expansions) is another constraint that could limit gas-based power plant development in the interior parts of the country.

Cost of Fuels for Electricity Generation

The high cost of fuel for thermal generation has been a key challenge for the Ghana power sector, as higher fuel costs result in overall higher tariffs for consumers, especially as the share of hydropower in the generation mix is decreasing.

- 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 costs of delivered gas from Sankofa fields was set at $9.8/MMBtu. However, the actual cost of Sankofa gas will be lower, due to the lower capital investment costs than initially anticipated. 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 increased delivered cost to above $8/MMBtu. At the same time, 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

[23] Sankofa take-or-pay obligation became active by the end of September 2018.

2016$). It is important to recognize that the gas prices would change over time in the future. For example, the PURC approved gas prices at $7.29/MMBtu in 2018.

- Diesel, HFO, and LCO have higher prices, and their delivered cost would be in the range of $11–$15/MMBtu.

In addition, to increase reliability of generation from thermal power plants, it is critical to maintain adequate fuel storage facilities for LCO and HFO in Aboadze and Tema. On the other hand, the cost of fuel storage further increases the cost of the fuel, although it contributes to increased reliability of electricity supply.

As a result of the high costs of fuels, the national average bulk generation cost is about US cents 9.0/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 and Kpong).

Reducing the high average cost of bulk generation can be achieved through reduction of fuel costs for thermal generation e.g., minimising the use of diesel, LCO, and HFO in the thermal generation mix, and greater use of relatively cheaper natural gas as well as renewable sources. Coal and nuclear options can also be considered as potential options.

Renewable Energy Use

Globally, increased production of electricity from most renewable energy sources is now a cost-effective option, especially since the capital costs of renewable energy power plants have declined drastically over the past 3 to 5 years.

The Renewable Energy Act (Act 832) seeks to promote the wider scale utilisation of renewable energy resources and requires that a specified target, in percentage terms, of renewable energy in the electricity generation mix, must come from renewable energy sources (e.g., solar, wind, biomass, small hydro, biogas, waste-to-energy, tidal). The Act also specifies REPOs, which must be fulfilled by utilities and bulk customers.

The Government of Ghana under a number of different initiatives has called for specific renewable energy targets. For example, the Renewable Energy Development and Management Programme (REDP) aimed to accelerate the development and utilisation of renewable energy and energy efficiency technologies to achieve 10 percent penetration of national electricity and petroleum demand mix by 2020; the 2010 Energy Sector Strategy and Development Plan (ESSDP) emphasises 'increasing the renewable energy supply in national energy mix to 10% by 2020'.[24] More recently, the Government of Ghana under its commitment under the Paris Agreement intends to "scale up renewable energy penetration by 10% by 2030".[25] In February 2019, the Energy Commission released a Renewable Energy Master Plan (REMP), which sets more specific targets for specific technologies.

[24] Ghana Renewable Energy Master Plan (REMP); February 2019. http://energycom.gov.gh/rett/documents-downloads/category/29-re-master-plan?download=174:final-remp-document

[25] 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

Meeting these targets would require significant increase in deployment of grid-connected renewable energy sources. As part of this effort, VRA has installed a 2.5-MW solar plant at Navrongo and is making efforts to install another 12-MW grid-connected solar PV plant at Kaleo and Lawra to fulfil its obligations. BXC Solar has installed a 20 MW solar power plant at Winneba and ECG is planning for another 20-MW plant in the Central Region. Bui Power Authority (BPA) has also made provisions to install up to 250 MW grid-connected solar PV.

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, some of which are well into the advance stages of development; however, none of these projects has yet reached the financial close phase.

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 been evaluating the impacts of large utility scale solar PV grid integration. 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. (See section G of IPSMP Volume 3 for details.[26])

On the other hand, new small hydropower, biomass combustion, and waste-to-energy projects are relatively expensive, but have social and environmental benefits, in addition to being dispatchable. Other technologies, such as tidal-wave, have also been proposed, but they are only at a preliminary stage.

Nuclear Option for Power Generation

To enhance the security of power supply in the country, the diversification of power generation resources is often contemplated as a key option. In this context, generation from nuclear power is currently being considered in Ghana.

Ghana's nuclear vision

The vision of using nuclear power for electricity generation in Ghana was first conceived and initiated by the country's first president, Dr. Kwame Nkrumah. He consequently established the Ghana Nuclear Reactor Project (GNRP) in 1961. The Ghana Nuclear Reactor Project was intended to introduce nuclear science and technology into the country and exploit nuclear energy in its peaceful applications to aid in national development. It was expected that in the long-term, the research reactor facility under the GNRP would support the development of manpower and promote plans for the introduction of nuclear power as a source of electricity production. In 1963, the Ghana Atomic Energy Commission (GAEC) was established to realize these long-term objectives.

Efforts to Acquire a Nuclear Research Reactor

GAEC therefore made efforts to acquire a two MW research reactor from the then Soviet Union. The research reactor was to be used to train and develop the required human resources for operating a future nuclear power plant for electricity generation to complement

26 http://www.energycom.gov.gh/files/Ghana%20Integrated%20Power%20System%20Master%20Plan%20_Volume%203.pdf

the generation from Akosombo hydropower plant. Although, the foundation stone for the construction of the research Reactor Building was laid in November 1964, the reactor project was however cancelled when the Nkrumah-led government was overthrown in 1966 through a military coup d'état.

The reactor project was reactivated in 1973 with efforts to acquire a new 1 MW reactor, which was a donation from the Federal Republic of Germany. However, the delivery of the new 1 MW research reactor from Germany was also cancelled by the German government as a result of yet another military take-over in 1981. The effort to acquire a nuclear research reactor was resuscitated again in March 1995, when a 30-kW miniature neutron source research reactor was commissioned at the Ghana Atomic Energy Commission facility by GAEC. The purpose of the research reactor is to serve as a source of neutrons for neutron activation analysis at research institutions, universities and hospitals for the purpose of teaching and learning. This small research reactor has been in operation since 1995 without incident.

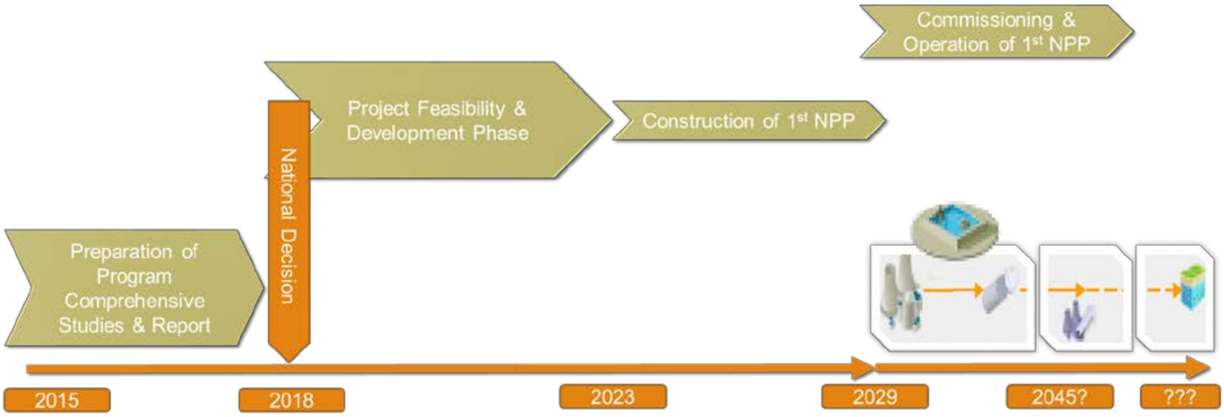
Nuclear Power for Electricity Generation in Ghana

The idea of nuclear power plant as a source of electricity generation regularly becomes part of the national energy policy discussions, especially whenever there is a power supply crisis. However, these discussions and ideas have so far been short lived and have not culminated into any concrete actions. This has been especially so because when the electricity generation situation became normalized, policy-makers tended to overlook the need for sustainable electricity generation mix. Often alternative options (such as oil and gas plants) were preferred because they quickly resolved the past power crisis situations, rather than investing in a nuclear power plant, which is neither fast nor cheap.

Nonetheless, after the electricity supply crisis in 2006/07, the Government of Ghana set up a Presidential Committee on Nuclear Power (PCNP) in May 2007 to investigate the role of nuclear power for electricity generation in Ghana. After their study, the PCNP concluded that nuclear power was viable for electricity generation in Ghana. The PCNP further accomplished the following: (i) prepared a roadmap for the establishment of a nuclear power plant for electricity generation within ten years, and (ii) proposed the establishment of a Presidential Commission on Nuclear Power Development [which was to act as the Nuclear Energy Programme Implementation Organisation (NEPIO)] to supervise the implementation of the roadmap.

On the submission of PCNP report to Government, the Government of Ghana took a Cabinet decision in December 2008 to include nuclear energy in the country's electricity generation mix. However, the implementation slowed down due to the change of government in January 2009.

Figure 8: Ghana Nuclear Power Programme Roadmap



Source: Ministry of Energy, 2016.

In September 2012, Government set up the Ghana Nuclear Power Programme Organisation (GNPPO) under the auspices of the Ministry of Energy with the mandate to coordinate, oversee, and administer the phase-by-phase implementation of the nuclear power programme in Ghana. GAEC also established a Nuclear Power Centre (NPC), which has a number of technical working groups, alongside the GNPPO to focus on various aspects of the nuclear power programme. In March 2015, an updated draft roadmap was completed by the NPC, which was reviewed by the International Atomic Energy Agency (IAEA) in November 2015 and subsequently approved by the GNPPO. The Roadmap for Nuclear Power projects anticipates that the country will add about 1000 MW nuclear power generation to its electricity generation mix within 14 years, taking 2015 as a base year. Figure 8 shows the proposed roadmap for the construction of the first nuclear power plant.

In 2016, NPC was upgraded into a Nuclear Power Institute (NPI). In addition, the country enacted the necessary nuclear legislations (i.e., a comprehensive nuclear law—the Nuclear Regulatory Act, 2015; Act 895) and established the Nuclear Regulatory Authority (NRA) in January 2016, as required by the IAEA. Ghana has also entered into bilateral discussions with a number of potential suppliers of the nuclear technology and fuel, including for example, state-owned nuclear institutions in Russia and China.

Regardless of the current plans in the nuclear energy roadmap, the Government of Ghana because of the high upfront cost implications, will have to weigh the nuclear option against other electricity generation options to make a final decision on building such a plant. Government will have to consider the implications associated with nuclear power utilization such as the high capital cost of the plant, nuclear safety, waste management, nuclear security and safeguard measures versus expected benefits such as enhancement of national energy security in meeting growing energy demand, climate change mitigation and technology transfer.

For example, the capital cost of a 1200-MW plant is estimated to be about US $5–$6 billion,[27] which would require significant investment by the Ghana government. A number of financing models have been developed for funding the new reactors that are currently under construction worldwide, including: (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.[28] The Government of Ghana has chosen a joint government and vendor financing model to finance the country's nuclear power plant.[29]

The high capital costs could be offset by the savings on the fuel, especially if compared to high potential prices on natural gas or coal. So, if Ghana develops significant indigenous natural gas at low prices, then the high capital cost of nuclear plants may make it less attractive. If, however, indigenous natural gas resources are not developed in the long run due to challenges with economics or geological limitations, then nuclear power would become an attractive option in the long-term (by mid-2030s and beyond). The country also faces several challenges regarding nuclear power, such as effective project management since any delays in completion of the nuclear power project could significantly increase project cost, and ensuring independence of the nuclear regulatory authority to implement regulations and protocols on safety and safe-guards without any political interference or conflicts of interest.

Coal Option for Power Generation

After the 2006/07 power supply crisis, the government policy not only included the consideration of nuclear energy, but also coal, in the national electricity generation mix. The 2010 National Energy Policy document called for evaluating a potential coal plant to be built in Ghana. The disruption to the supply of gas from Nigeria in 2012 brought to the fore the need for alternative fuel options such as coal. VRA evaluated the potential coal option in Ghana and together with the Shenzhen Energy Group (SEG) developed a specific plan to embark on a 4 x 350 MW supercritical coal-fired plant (in two 2 x 350 MW phases) together with the affiliated Coal Handling Terminal (CHT) at Ekumfi Aboano in the Ekumfi District of Central Region.

Based on the VRA and SEG joint venture agreement, pre-feasibility and full feasibility studies have been completed and reports have been developed and presented to key stakeholders for review. 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.

It has been estimated that about 2 million tonnes (for the Phase 1) and 6 million tonnes of coal (for Phase 2) would have to be imported from Columbia and South Africa every year to

[27] 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).
[28] 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).
[29] 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).

fuel the plant. The proposed project has, however, stalled due to public agitation about the adverse potential environmental effects of the coal power plant. The burning of coal may also undermine the country's commitment to the Paris Agreement.[30]

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).[31] Although these are general efficiency estimates, the specific efficiency for a power plant in Ghana would be affected by higher water and air temperatures in the country (relative to plants in the United States or Europe). The capital costs of supercritical technologies are about 10–30% higher than the conventional coal plants;[32] however, the higher costs may be partially or wholly offset by fuel savings, depending on the price of fuel.

Similar to the nuclear power plants, any potential coal plant in Ghana faces the challenges of demand growth, potential low cost natural gas, financing the high investment costs, and 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.[33]

4.2.4. 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 does not lag the growth in demand. Currently, as a result of congestion and overloading of transformers in some segments of the network, investments for specific transmission upgrades are necessary (e.g., A4BSP, and additional lines to Kumasi and Bolgatanga). 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 northern parts of the West Africa subregion. Other challenges in network expansions and upgrades include land acquisition issues, which have continued to hamper timely completion of transmission and distribution infrastructure projects.

Distribution-level technical and commercial losses continue to remain high, and greater technological and operational improvements are needed over time to reduce these losses.

---

[30] "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).

[31] 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).

[32] Ibid.

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

Reliability improvements are particularly critical to ensure that distribution utilities (both ECG and NEDCo) can deliver power reliably to residential, commercial, and industrial customers. The distribution utilities, in the last few years, have focused on installing prepaid metres on a mass 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.

Table 2: Transmission and Distribution Losses in Ghana

Indicator	Source	Unit	2012	2013	2014	2015	2016	2017
ECG Aggregate Technical, Commercial Losses	ECG	%	23.48	22.98	25.18	22.71	23.88	24.55
NEDCo Aggregate Technical, Commercial Losses	NEDCo	%	21.20	21.20	22.00	23.10	27.00	26.00
NEDCo Collection Rate	NEDCo	%	68.66	89.66	65.83	71.00	73.00	71.00
ECG Collection Rate	ECG	%	95.00	94.42	89.76	93.24	81.06	93.33
GRIDCo Transmission Losses	GRIDCo	%	4.30	4.49	4.32	3.79	4.43	4.14

Source: PFG 2018 and IRRP.

4.2.5. Financial Challenges of the Power Sector

Financial challenges have plagued Ghana's power sector since the 1980s, due to the weakening of the country's currency and dwindling revenues, which were not keeping pace with escalating expenditures. Difficulties in purchasing crude oil regularly, when thermal generation was added to the generation mix, exacerbated the financial challenges in the late 1990s. Despite the increasing cost of electricity supply, electricity tariffs continued to be kept low and the sector consequently suffered financially.[34]

In 1997, to de-politicise the tariff-setting process, the Government of Ghana established the PURC, which was to be responsible for electricity rate setting instead of the Ministry of Energy. To bring financial sustainability into the power sector, PURC published the Electricity Rate Setting Guidelines and implemented a major tariff review on 1 February 1998. This tariff review caused a major public outcry, and as such, the tariffs had to be brought down in September 1998 even though it was not enough to bring financial health and sustainability to the utilities.

The PURC again reviewed electricity tariffs in May 2001 to improve the financial health and sustainability of the utilities, and in July 2002, published its proposed Transitional Plan for Electricity Rate Adjustment for the period 2001–2004.[35] A key component of the Transitional Plan involved the implementation of an Automatic Adjustment Formula (AAF) whose main objective was to adjust the electricity tariffs on a quarterly basis to reflect changes in input factors (e.g., the volatility in the spot price of LCO on the international oil market and the

[34] Electricity tariffs by the Ministry increased from GH¢ 0.07/kWh in 1980 to GH¢ 33.0/kWh in 1996.
[35] http://www.purc.com.gh/purc/sites/default/files/revised_aaf_implementation_notes.pdf Accessed 21 June 2018.

Ghana Cedi-U.S. dollar exchange rate) that were considered beyond the control of the utilities.

Although PURC has updated electricity tariffs over time,[36] and publishes its automatic tariff adjustments, these adjustments were sometimes not fully implemented due to promises of government subsidies. However, these government subsidies are often not provided directly to the utilities, and the government itself has sometimes failed to fully pay for its consumption—both of which result in increased debt to the utilities.

The financial challenges were exacerbated by the procurement of high-cost emergency power plants by the Government of Ghana through unsolicited proposals (as discussed earlier) during the *Dumsor* period. This resulted in the PURC imposing even higher tariffs (which were not fully passed through to consumers). For example, average end-user tariffs for electricity[37] increased by nearly four-fold (~350%) from GHS 0.232/kWh in 2012 (before the power deficit crisis) to GHS 0.817/kWh in 2016 (after the power deficit crisis) to allow the utilities to recover their costs of operations. However, even these high tariffs were not considered adequate by the utilities to cover their costs of operation, leading to under-recovery of costs and the current financial distress.

In addition, the inability to bring down distribution losses, which were higher than the benchmarked distribution loss level, as well as the persistent inefficiencies in billing and bill collection, led further to lower revenues for the utilities.

The high cost of electricity supply combined with the cross-subsidies that are included in the non-residential tariffs has resulted in a number of commercial and even industrial consumers switching from the grid supplied electricity to self-generation (using diesel gen-sets and solar PV systems). For these consumers, self-generation offered them (i) a lower cost of supply and therefore reduced the cost of their operations, and (ii) mitigated their concerns of unreliable grid power supply. The switch to self-generation by the industrial and commercial electricity consumers resulted in significant decrease in the revenues of the utilities, which further worsened their financial situations.

As a result of all these issues, as well as due to poor management of its own financial resources, DISCos do not fully pay both the GENCos for bulk electricity supplied and the GRIDCo for transmitting electricity to them. Over time, this has led to a high level of debt within the system, which consequently affected all players in the power supply chain, banks, and other lenders.

The total debt owed in the power sector is overwhelming and cannot be retired completely in the short term. The Government of Ghana is adopting a number of new initiatives and strategies to address the challenge of the outstanding total debt in the power sector.

From a planning perspective, it is imperative that Ghana's future power system is based on a least-cost optimised approach that takes into consideration the existing supply and existing contractual obligations, as well as the transmission and distribution constraints. An optimised least-cost and Least-Regrets Portfolio (see below) will reduce the future costs of expansion and help limit the financial burden on the utilities.

[36] Electricity tariffs by PURC for example increased from GH¢ 34.5/kWh in 1997 to GH ¢ 930.2/kWh in 2007.

[37] Ghana National Energy Statistics – 2017, page 28.

4.2.6. Wholesale Electricity Market

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

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

- The structure of the WEM and the overall rules that govern the WEM; and
- Establishment of an Electricity Market Oversight Panel (EMOP), which would, inter alia, monitor the general performance of electricity transmission, 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 expected to influence the electricity planning environment and landscape. For instance, the level of planning reserve margin would influence investments in generation for the provision of a separate ancillary market, capacity market, and energy market under the WEM. Consequently, any time the actual reserve margin falls below the stipulated minimum, which is the planning reserve margin, the capacity market or ancillary services market will automatically initiate calls for a competitive bidding process for the procurement of additional capacity.

Further, if locational marginal pricing or nodal pricing are implemented under the WEM (instead of the current postage stamp prices), price differences across the various locations could attract investors to make investments that reduce congestions on the transmission network.

Consequently, implementation of WEM could lead to greater competition and unleash market forces that would address efficient dispatch and resolve local or zonal generation deficiencies. Thus, the timing and implementation of WEM will be key for future planning. The modelling framework used for this IPSMP is consistent with the WEM, and zonal prices can be ascertained by the selected planning model.

5. Modelling Framework

5.1. Background

The Integrated Resource and Resilience Planning (IRRP) Technical Committee, headed by the Energy Commission (EC), selected the Integrated Planning Model (IPM®)[38] 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.[39] 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.

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

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.

Table 3 shows an illustrative list of power system planning tools considered by the Technical Committee. These tools are generally categorised along their planning functions, although many tools can be used for multiple purposes. The tools in the red box in Table 3 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

[38] IPM has been used and continually developed for over 30 years and is being used in the U.S., Europe, Africa, and Asia.

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

Table 3: 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
Most applicable to IRRP				WASP

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

5.2. 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 and implications of alternative strategies/policies.

5.2.1. 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.

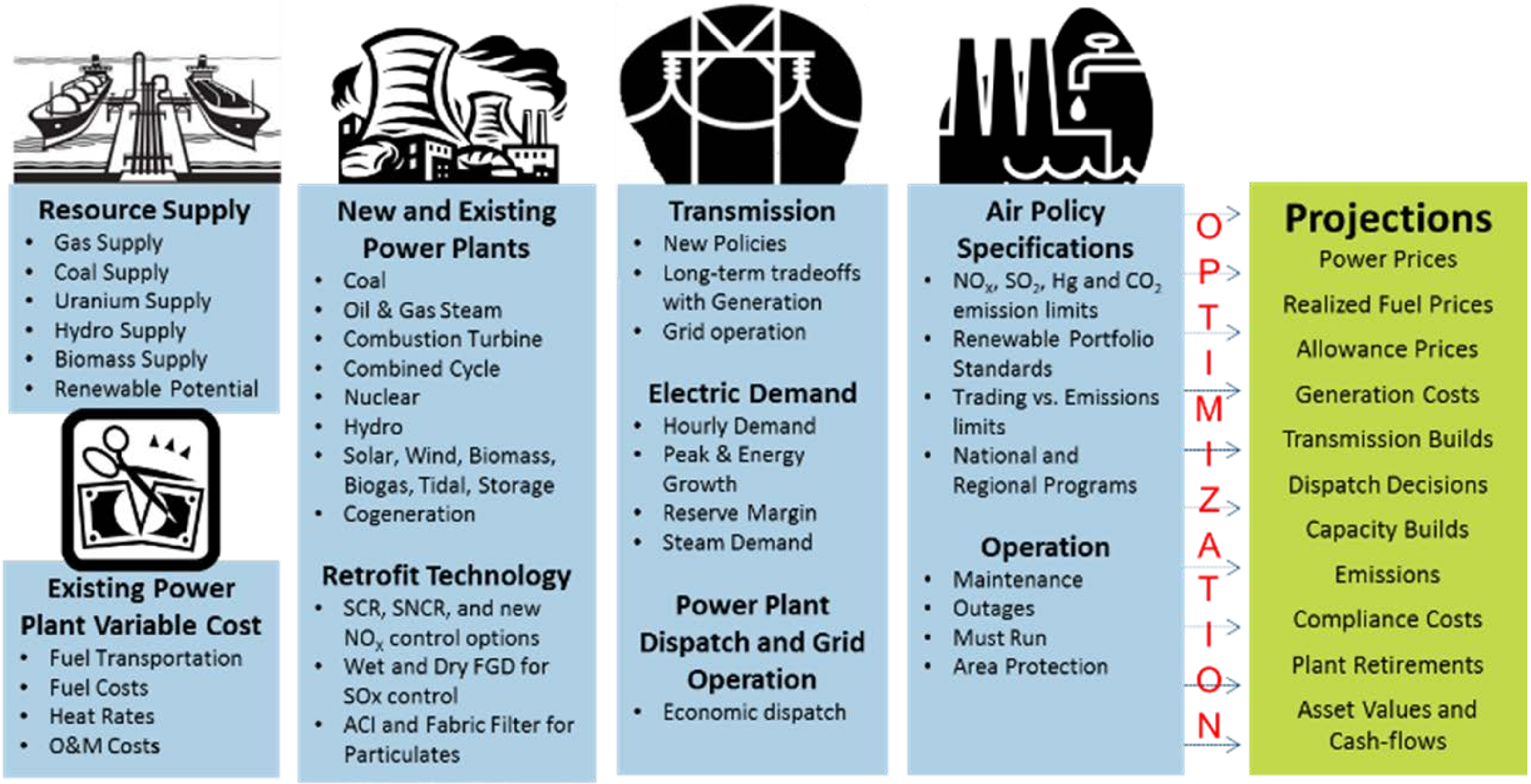
IPM employs a bottom-up partial equilibrium and dynamic linear programming model for the optimisation of the electric generation and transmission within each zone/region as well as the transmission lines that connect the zones to meet the electricity demand at the least cost. The model also projects 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 9 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 build patterns based on 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.

Figure 9: Framework for Ghana Integrated Planning Model (IPM)



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

Although the IPM is capable of explicitly modelling individual (or aggregated) end-use energy efficiency investments, this feature was not considered in this initial study due to lack of sufficient data on energy efficiency improvement. 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.

5.3. Model Structure and Formulation

IPM consists of three main structural components: the linear "objective function", a series of "decision variables", and a set of linear "constraints".[40]

5.3.1. 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.)

IPM's objective function is to minimise the total, discounted net present value of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon. The objective function represents the summation of all the costs incurred by the electricity sector on a net present value (NPV) basis. It is these costs that the linear programming formulation attempts to minimise. The total cost includes the cost of new plants (*NewCapCosts*), transmission costs (*TransCosts*), the generation costs (*GenCosts*), which includes fixed and variable operating and maintenance costs and fuel costs, among others.[41] Cost escalation factors are also used in the objective function to reflect changes in cost over time. The applicable discount rates are applied to derive the NPV for the entire planning horizon from the costs obtained for all years in the planning horizon.

[40] Large parts of this section have been based on IPM documentation from the U.S. EPA, which is using IPM for its modeling. See: https://www.epa.gov/sites/production/files/2018-06/documents/epa_platform_v6_documentation_-_all_chapters_june_7_2018.pdf

[41] Emission Allowance Costs (*EmissAllowanceCosts*) is cost of meeting emissions constraints if such binding constraints are included in the modeling. Unserved Energy Costs (*UnservedEngyCosts*) is the cost of not meeting load or energy demand in a particular model zone.

A discount rate is used to translate future cash flows into current dollars, and it considers factors such as expected inflation and the ability to earn interest. This makes one dollar today worth more than one dollar tomorrow. The discount rate allows intertemporal trade-offs and represents the risk adjusted time value of money.[42]

5.3.2. Decision Variables

Decision variables are the values being solved in the IPM, given the least-cost function and the set of electric system constraints. The model determines values for these decision variables that represent the optimal least-cost solution for meeting the assumed constraints.

The key decision variables represented in the IPM are:

Generation Dispatch Decision Variables: IPM includes decision variables representing the generation from each model power plant. For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve applicable to the model plant. In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price to obtain a fuel cost. It is also multiplied by the applicable VOM cost rate to obtain the VOM cost for the plant.

Capacity Decision Variables: IPM includes decision variables representing the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables representing existing capacity and capacity additions are multiplied by the relevant FOM cost rates to obtain the total FOM cost for a plant. 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: IPM includes decision variables representing the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

5.3.3. Constraints

Model constraints are implemented in IPM to accurately reflect the characteristics of and the conditions faced by the electric sector. Some of the key constraints included in the *GH-IPM 2018v1* (first released version of the GH-IPM) are: reserve margin, demand, capacity factor (used only for selected plants), turndown/area protection, transmission, and fuel supply constraints.

5.4. 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

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

methodological and structural features of IPM that extend beyond the assumptions that are specific to the *GH-IPM 2018v1*.

5.4.1. Model Plants

Model plants are a central structural component that IPM uses in three ways:

- To represent aggregations of existing generating units;
- To represent retrofit and retirement options that are available to existing units; and
- To represent potential (new) units that the model can build.

Existing Units: This refers to generation units in existing plants (i.e., plants that are already in operation) in the country. For the *GH-IPM 2018v1*, all existing plants as of March 2017, totalling 25, were characterised. The total number of units within these plants is 245. For the *GH-IPM 2018v1,* 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 build decisions have already been taken, as "firmly planned". For the *GH-IPM 2018v1*, 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 can utilise model plants to represent the retrofit and retirement options that are available to existing and firmly planned units. However, this capability of IPM was not utilised in the *GH-IPM 2018v1* version—although it will be included in the next versions.

Potential (New) Units: IPM also uses model plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are predefined at set up, differentiated by type of technology, regional location, and years available. When it is economically advantageous to do so (or otherwise required by reserve margin constraints to maintain electric reliability), IPM "builds" one or more of these predefined model plant types by raising its generation capacity from zero to a value that would meet peak and energy demand, and reserve margin in any given year, during the course of a model run.

In determining whether it is economically advantageous to "build" new plants, IPM considers cost and performance differentials between 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 2018v1* version.

5.4.2. Model Run Years

Another important structural feature of IPM is the use of model "run years" to represent the full planning horizon being modelled. Mapping each year in the planning horizon into a representative 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 considers the costs in all years in the planning horizon. Often, models like IPM include a final model run year that is not included in the analysis of results. This technique reduces the likelihood that modelling results in the last represented year will be skewed due to the modelling artefact of having to specify an end point in the planning horizon, whereas, in reality, economic decision-making will continue to take information into account from years beyond the model's time horizon.

5.4.3. Cost Accounting

As mentioned earlier, IPM is a dynamic linear programming model that finds the least-cost investment and electricity dispatch strategy for meeting electricity demand subject to resource availability and other operating and environmental constraints. The cost components that IPM takes into account in deriving an optimal solution include the costs of investing in new capacity options, fuel costs, the operation and maintenance costs associated with unit operations, among others. Several cost accounting assumptions are built into IPM's objective function that ensure a technically sound and unbiased treatment of the cost of all investment options offered in the model. These features include the following:

- Discounting of all costs in IPM's single multi-year objective function to a base year. Since the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.
- Capital costs in IPM's objective function are represented as the NPV of levelised stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelised annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter.
- This approach avoids presenting artificially higher capital costs for investment decisions taken closer to the model's time horizon boundary simply because some of that cost would typically be serviced in years beyond the model's view. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

The cost components informing IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in individual model run years. This permits the model to capture the escalation of the cost components over time accurately.

5.4.4. 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,[43] but it is not designed to capture retail distribution costs. However, the model implicitly includes distribution losses since net energy for load,[44] rather than delivered sales,[45] is used to represent electricity demand in the model.

[43] 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.

[44] 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.

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

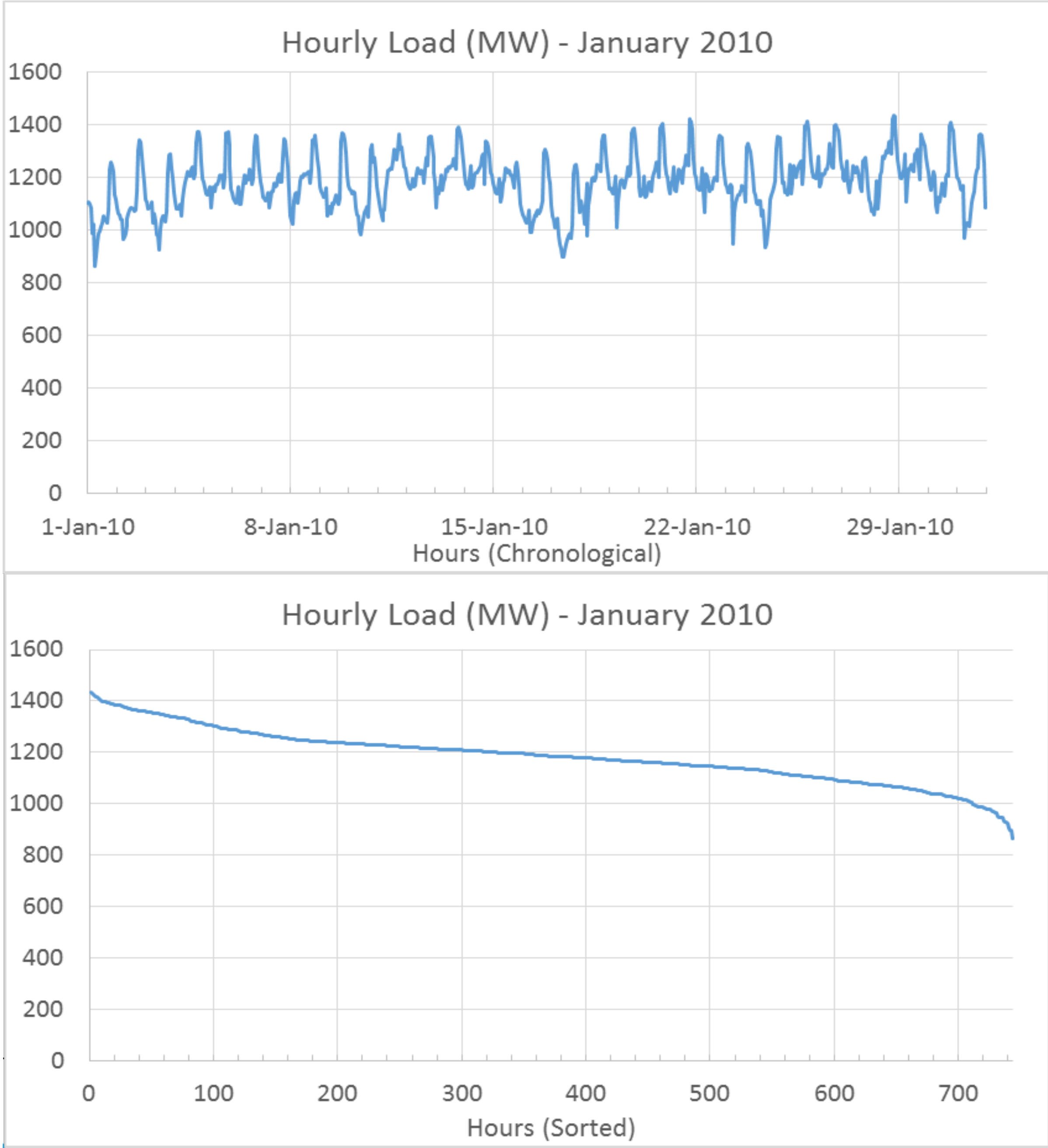
Additionally, the production costs calculated by IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as *carrying (capacity) charges of existing units* that are ultimately part of retail cost incurred by customers.

5.4.5. Load Duration Curves

IPM uses load duration curves (LDCs) to provide realism to the dispatching of electric generating units. Unlike a chronological electric load curve, which is simply a sequential hourly record of electricity demand, LDCs are created by rearranging 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 2018v1* has used months as seasons, and so every year has 12 LDCs.** Figure 10 presents a chronological hourly load curve for the month of January 2010 and a corresponding LDC for that month consisting of 744 hours.

Figure 10: Illustrative Load Curves (Chronological and Sorted)



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).

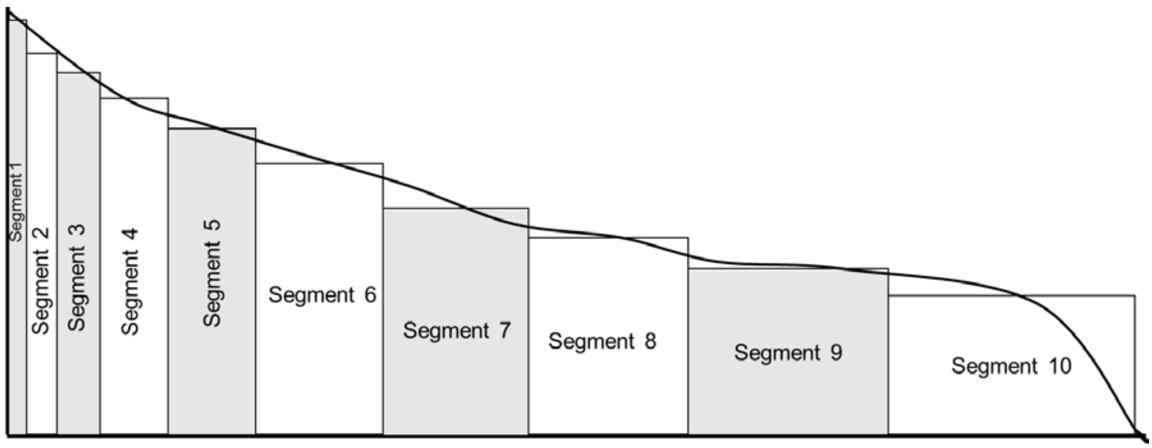
Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 11. ***GH-IPM 2018v1*** **uses 10 load segments in its seasonal LDCs for model run years 2016–2040.** Therefore, every year has 120 load segments (12 months x 10 segments). Figure 11 illustrates the 10-segment LDCs used in the model. Length of time and system demand are the two parameters which 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 11 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 11: Representation of Load Duration Curve Used in *GH-IPM 2018v1*

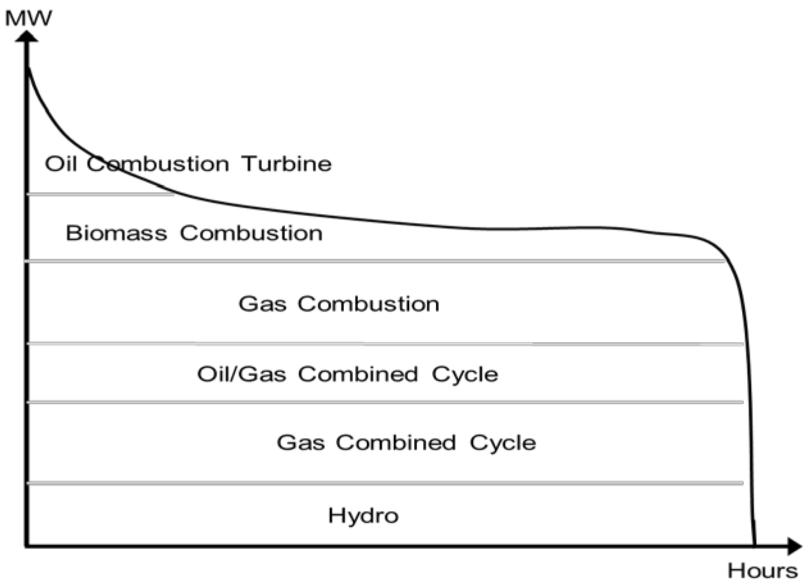


5.4.6. Dispatch Modelling

In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the power plant that generates the last unit of electricity, sets the energy price for that load segment. Physical operating constraints also influence the dispatch order. For example, IPM uses turndown constraints to prevent base load units from cycling, i.e., switching on and off. Turndown constraints often override the dispatch order that would result based purely on the variable cost of generation. Variable costs in combination with turndown constraints enable IPM to dispatch generation resources in a technically realistic fashion.

Figure 12 depicts a highly stylised dispatch order based on the variable cost of generation of the resource options included in the *GH-IPM 2018v1*. A hypothetical LDCs is subdivided according to the type of generation resource that responds to the load requirements represented in the curve. The generation resources with the lowest operating cost respond first to the demand represented in the LDC and are accordingly at the bottom of “dispatch stack.” They are dispatched for the maximum possible number of hours represented in the LDC because of their low operating costs. Generation resources with the highest operating cost (e.g., peaking turbines) are at the top of the “dispatch stack,” since they are dispatched last and for the minimum possible number of hours.

Figure 12: Hypothetical Dispatch Order in *GH-IPM 2018v1*



5.4.7. Unserved Energy

IPM® will allow unserved energy in the problem optimization if all possible lower cost generating options have been exhausted. By default, the 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. Unserved energy calculation is performed for every year and season. Note that because the cost of unserved energy is usually very high, all units will be dispatched before energy is left unserved.

5.4.8. Fuel Modelling

IPM allows for the modelling of the full range of fuels used for electric power generation. The cost, supply, and (if applicable) quality of each fuel included in the model are defined during model set up. Fuel price and supply can be represented in IPM in one of three alternative ways: (i) through an embedded modelling capability that dynamically balances supply and demand to arrive at fuel prices (natural gas), (ii) through a set of supply curves, or (iii) through an exogenous price stream.

In the *GH-IPM 2018v1*, 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.

5.4.9. 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.

5.4.10. Perfect Competition and Perfect Foresight

IPM methodology assumes perfect competition and perfect foresight. The former means that IPM models the production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The model does not explicitly capture any 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 the electricity market knows precisely the nature and timing of conditions in future years that affect the ultimate costs of decisions along the way. For example, under IPM there is 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.

5.5. Data Parameters for Model Inputs and Outputs

5.5.1. 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

5.5.2. 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

6. 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. A detailed information on these assumptions is available through MS Excel files at the EC website.

The following list presents the modelling parameters that were used for the IPSMP modelling, and they are described in this chapter:

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

6.1. 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,[46] and NorthGH (see Figure 13).

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.

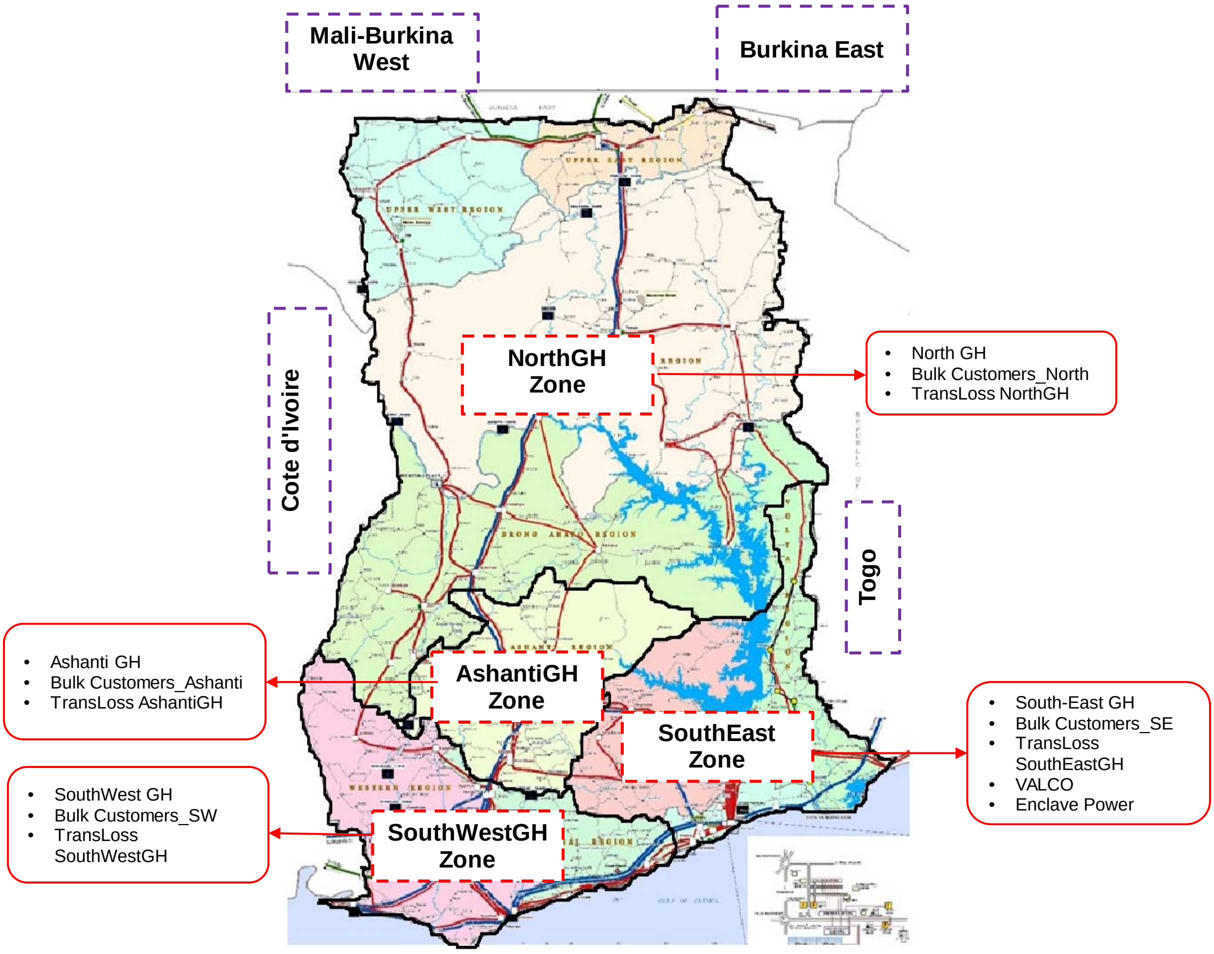
Table 4: Description of Ghana Model Zones and Regions

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 – SouthEastGH	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
Togo	Togo	Power exchange with Southern and Northern Togo
Cote d'Ivoire	Cote d'Ivoire	Power exchange with Cote d'Ivoire

46 AshantiGH zone represents the Middlebelt areas of Ghana.

Ghana Zone	Model Region	Geographical/Demand Coverage
Mali-Burkina	Burkina East	Power exchange with Ouagadougou, Burkina Faso
	Mali-Burkina West	Power exchange with Bobodilassou (Burkina) and Bamako (Mali)

Figure 13: Ghana Zones and Modelling Regions



Source: IRRP Project, based on GRIDCo transmission map.

6.2. High Level Assumptions

6.2.1. Run Years and Mapping

As discussed in section 5.4.2, 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 5. 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 2017, 2018, 2019, 2020, 2023, 2026, 2030, 2035, and 2040.

The analysis time horizon for GH IPM 2018 v.1 extends from 2017 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 5.

Furthermore, the *GH-IPM 2018v1* 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 year. See section 5.4.5.

Table 5: Year Map used in *GH-IPM 2018v1*

Run Year	Years Represented	Number of Years
2017	2017	1
2018	2018	1
2019	2019	1
2020	2020 - 2021	2
2023	2022 - 2024	3
2026	2025 - 2027	3
2030	2028 - 2032	5
2035	2033 - 2037	5
2040	2038 - 2040	3

6.2.2. Financial Assumptions

In terms of cost calculation, the GH IPM 2018 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 2018v1* model**, and is based on the real weighted average cost of capital (WACC).[47] WACC for all future power plants is assumed to be 10%, based on specific assumptions about debt-to-equity ratios, and the loan interest rate and rate of return on equity.[48]

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.[49] In practice, the WACC will vary for different types of power plants and transmission lines, but additional analysis is required to determine the WACC for new power plants in Ghana. For the GH-IPM 2018v1 model, all of the new plants has the same CCR of

[47] 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

[48] The debt-to-equity ratio is generally assumed to be 70:30, and loan rate is assumed to be 6%, with return on equity at 20% in real terms.

[49] 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

10.8%. However, future versions of the model will include updated CCRs based on the specific financial characteristics of the plants.

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.

6.3. 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 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 Volume 3 IPSMP report.

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,[50] and historical annual electricity consumption in GWh as the dependent variable.[51] 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.

[50] 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.

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

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 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[52] to 7% in 2030.[53] 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 modeling zones, based on expected ratios among the ECG operational regions, 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.[54] 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.

[52] 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.

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

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

6.3.1. 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 6. The expectation is that all of VALCo's six potlines will be fully utilised over the next 5–6 years.

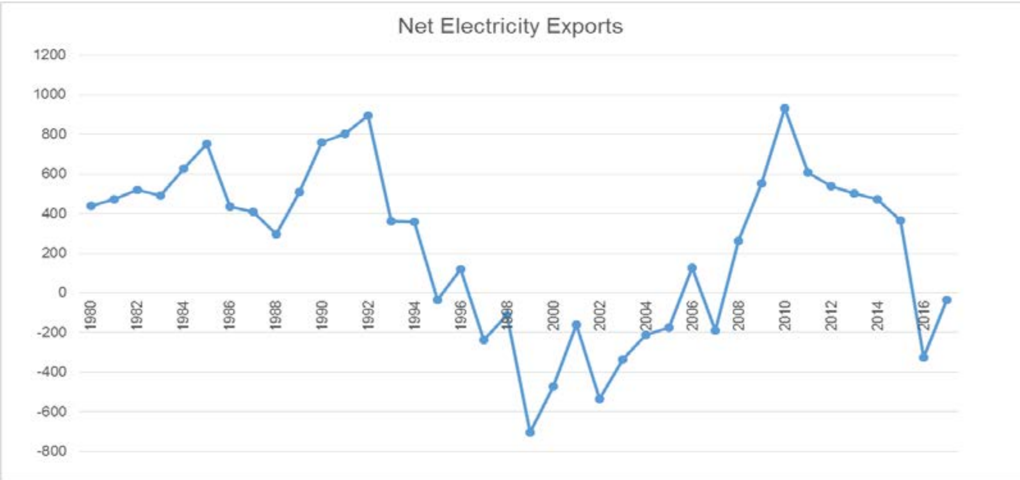
Table 6: VALCO Peak and Energy Forecast

Year	VALCO Forecast	
	MW	GWh
2017	75	624
2018	150	1248
2019	150	1248
2020	250	2081
2021	250	2081
2022	444	3695
2023	555	4619
↓	↓	↓
2040	555	4619

6.3.2. 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 put together as shown in Figure 14; although during periods of generation deficiencies, Ghana has been a net importer.

Figure 14: 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 15.

Figure 15: Energy and Capacity Exports

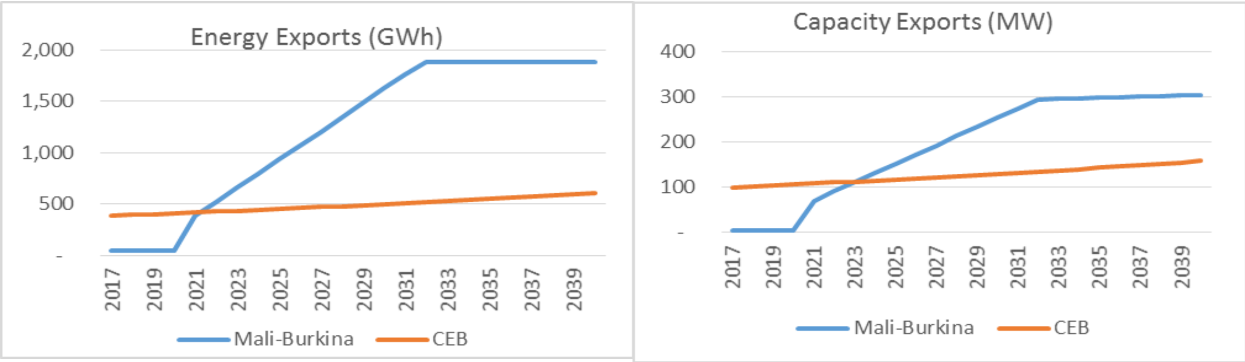


Table 7 and Table 8 show the Reference Case IPSMP energy and peak demand forecasts, respectively, for the different sectors. See Volume 3 IPSMP reports for details.

Figure 16 shows a comparison of the energy demand forecasts by the various institutions for the Ghana domestic sector with the IPSMP forecast, and Figure 17 shows the energy demand including demand for VALCO and exports. Figure 18 and Figure 19 compare the projected IPSMP peak demand forecasts with previous forecasts and actual peak demand. These comparisons **do not** make any statements on which forecasts are right or wrong, but are only meant to show 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 20 compares the GDP growth rate assumptions used in the various load forecast reports and for the IPSMP Reference Case forecast.

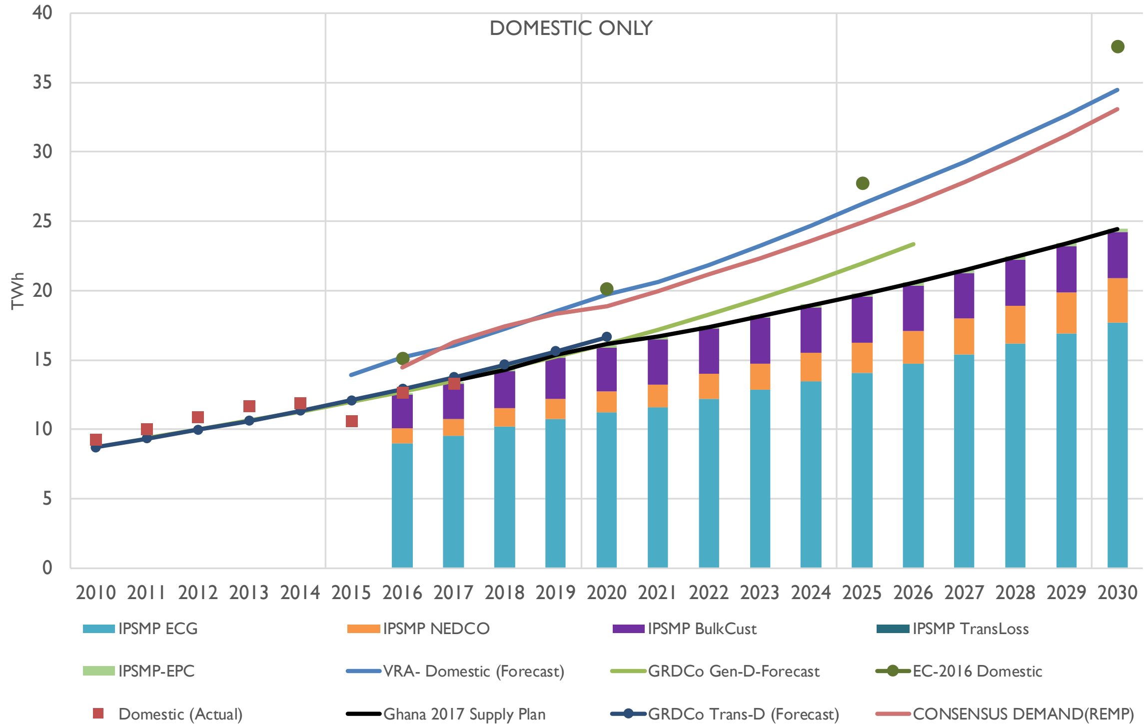
Table 7: Energy Demand Forecast

SUMMARY Annual Wholesale Generation Requirement [GWh]								
Year	ECG	NEDCo	EPC	Bulk Customers	VALCO	Exports	GRIDCO Trans Loss	Total Ghana
2017	9,535	1,196	131	2527	624	436	283	14,734
2018	10,190	1,328	158	2660	1,248	444	317	16,347
2019	10,760	1,447	168	2957	1,248	452	366	17,398
2020	11,214	1,545	180	3134	2,081	460	199	18,813
2021	11,607	1,631	192	3257	2,081	815	205	19,788
2022	12,216	1,768	204	3287	3,695	954	213	22,336
2023	12,838	1,913	215	3287	4,619	1,098	221	24,190
2024	13,445	2,058	227	3292	4,619	1,246	229	25,117
2025	14,059	2,208	239	3293	4,619	1,399	238	26,055
2026	14,710	2,371	239	3294	4,619	1,538	247	27,018
2027	15,424	2,556	239	3295	4,619	1,681	257	28,070
2028	16,161	2,751	239	3297	4,619	1,829	267	29,163
2029	16,923	2,959	239	3298	4,619	1,982	277	30,297
2030	17,720	3,182	239	3299	4,619	2,140	288	31,487
2031	18,608	3,424	239	3299	4,619	2,275	300	32,764
2032	19,545	3,685	239	3299	4,619	2,411	312	34,109
2033	20,524	3,965	239	3299	4,619	2,421	324	35,392
2034	21,552	4,267	239	3299	4,619	2,432	337	36,744
2035	22,631	4,591	239	3299	4,619	2,442	350	38,172
2036	23,766	4,940	239	3299	4,619	2,453	364	39,681
2037	24,958	5,317	239	3299	4,619	2,464	378	41,275
2038	26,209	5,721	239	3299	4,619	2,476	393	42,957
2039	27,523	6,157	239	3299	4,619	2,488	409	44,733
2040	28,902	6,128	239	3299	4,619	2,499	425	46,111

Table 8: Peak Demand Forecast

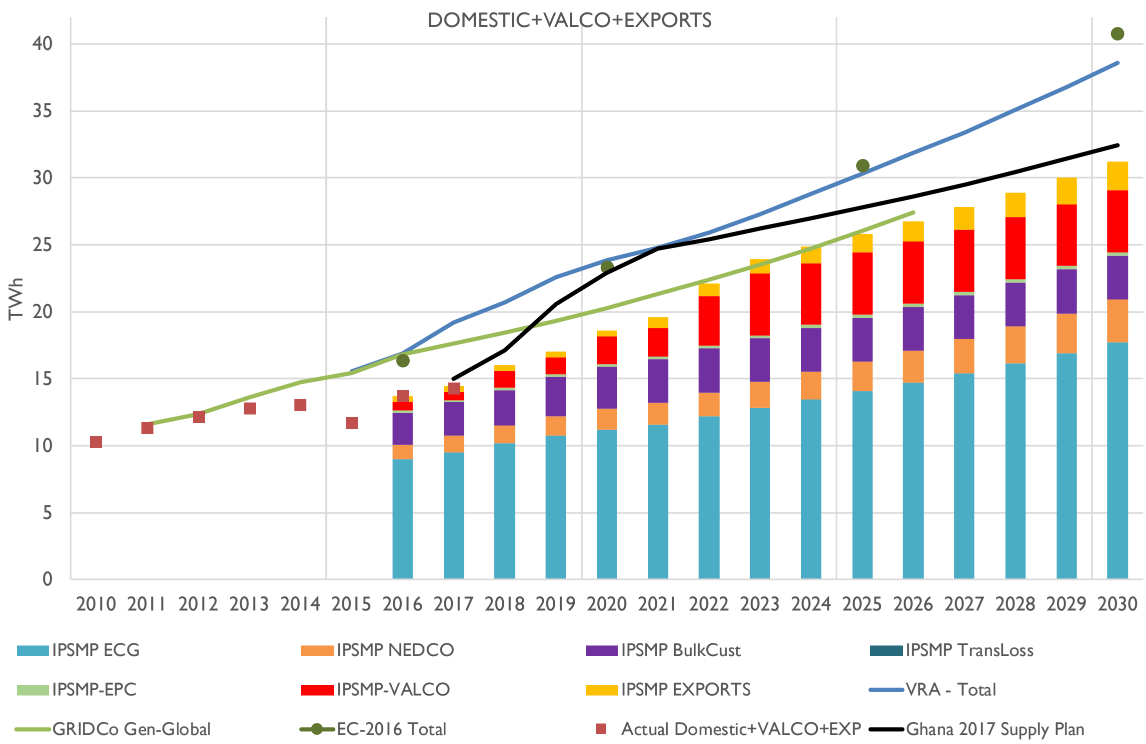
SUMMARY Annual Zonal-Coincident Peak Wholesale Demand Requirement [MW]								
Year	ECG	NEDCo	EPC	Bulk Customers	VALCO	Exports	GRIDCO Trans Loss	Total Ghana
2017	1,436	180	45	342	75	108	47	2,233
2018	1,535	200	46	359	150	110	53	2,453
2019	1,621	218	49	397	150	112	61	2,607
2020	1,689	233	53	419	250	114	33	2,791
2021	1,748	246	56	434	250	181	34	2,950
2022	1,840	267	60	438	444	204	35	3,287
2023	1,934	288	63	439	555	226	37	3,542
2024	2,025	310	67	439	555	249	38	3,683
2025	2,118	333	70	439	555	271	40	3,826
2026	2,216	358	70	440	555	294	41	3,973
2027	2,323	385	70	440	555	317	43	4,132
2028	2,434	415	70	440	555	339	44	4,298
2029	2,549	446	70	440	555	362	46	4,468
2030	2,669	480	70	440	555	385	48	4,647
2031	2,803	516	70	441	555	408	50	4,842
2032	2,944	556	70	441	555	431	52	5,048
2033	3,091	598	70	441	555	434	54	5,244
2034	3,246	643	70	441	555	438	56	5,450
2035	3,409	692	70	442	555	442	58	5,668
2036	3,580	745	70	442	555	446	61	5,898
2037	3,759	802	70	442	555	450	63	6,141
2038	3,948	863	70	442	555	455	65	6,398
2039	4,146	928	70	442	555	459	68	6,668
2040	4,353	924	70	443	555	463	71	6,879

Figure 16: Comparison of Ghana Domestic Electricity Demand Forecasts



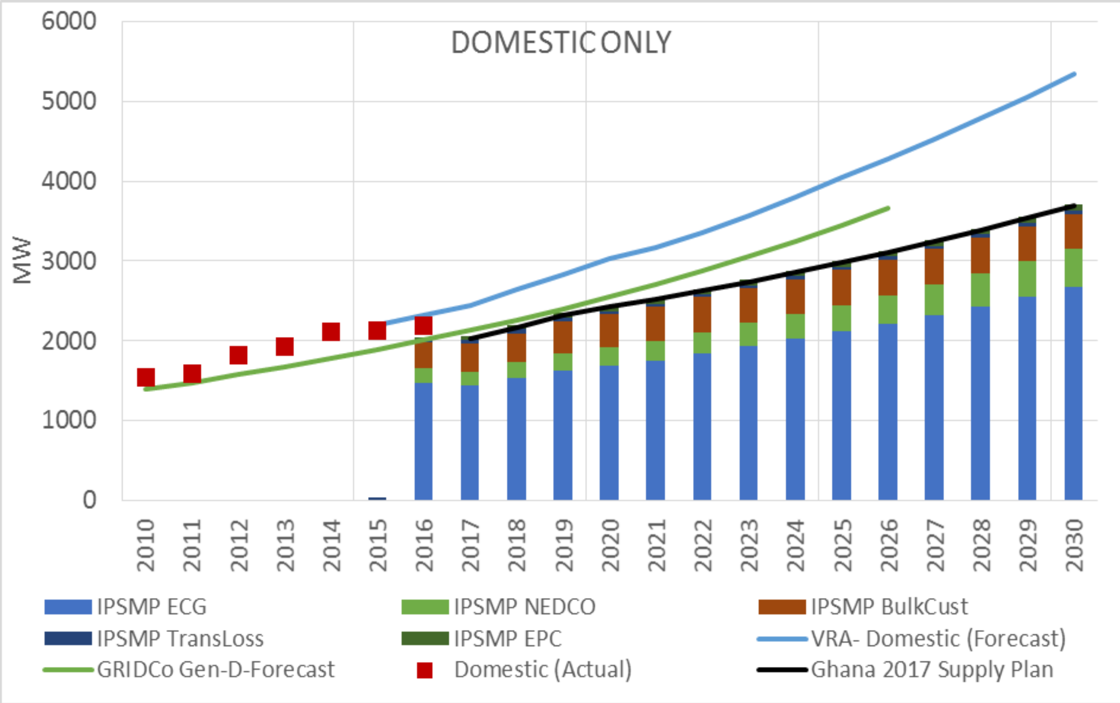
Source: IRRP Project.

Figure 17: Comparison of Total Ghana Electricity Demand Forecasts



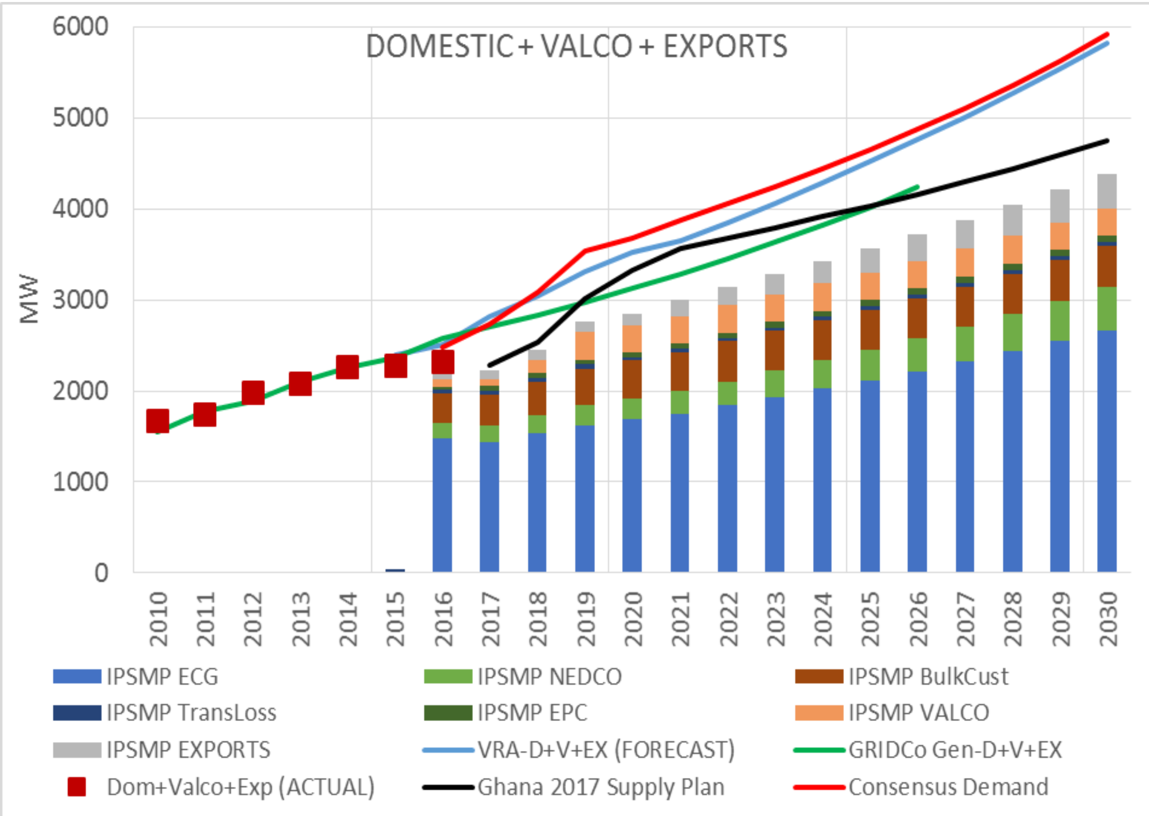
Source: IRRP Project.

Figure 18: Comparison of Ghana Domestic Peak Demand Forecasts



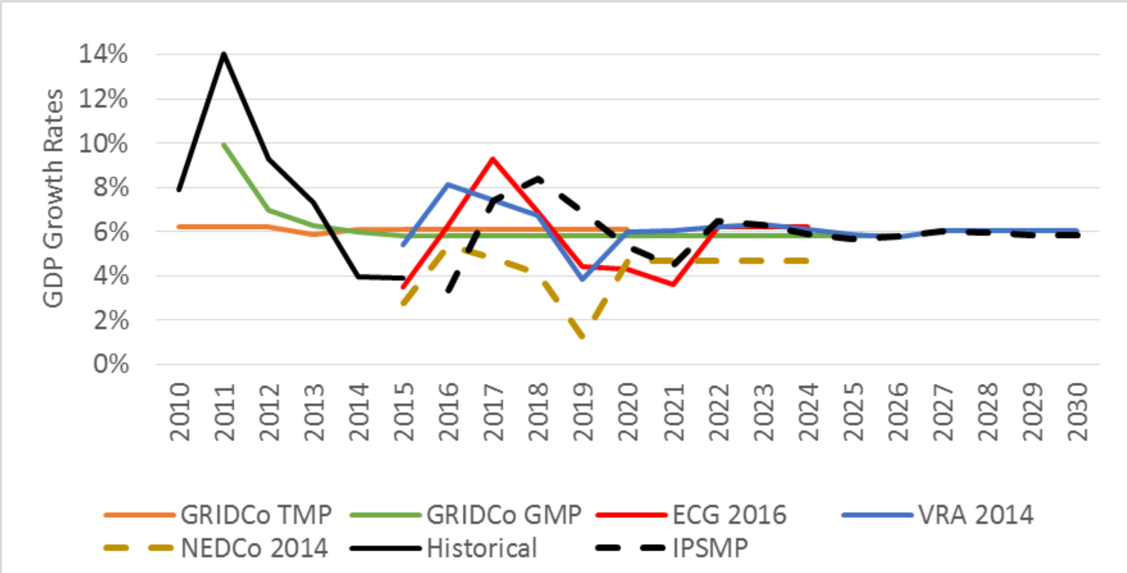
Source: IRRP Project.

Figure 19: Comparison of Total Ghana Peak Demand Forecasts



Source: IRRP Project.

Figure 20: Comparison of GDP Growth Rates used for Selected Forecasts



Source: IRRP Project.

6.3.3. Domestic Demand Sensitivity

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

Figure 21 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 22.

Figure 21: High and Low Energy Demand Forecasts

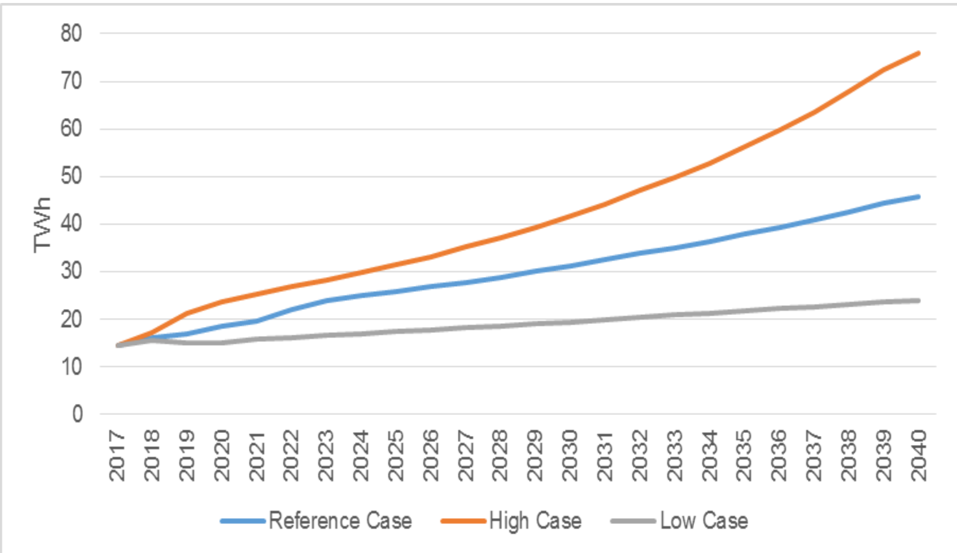
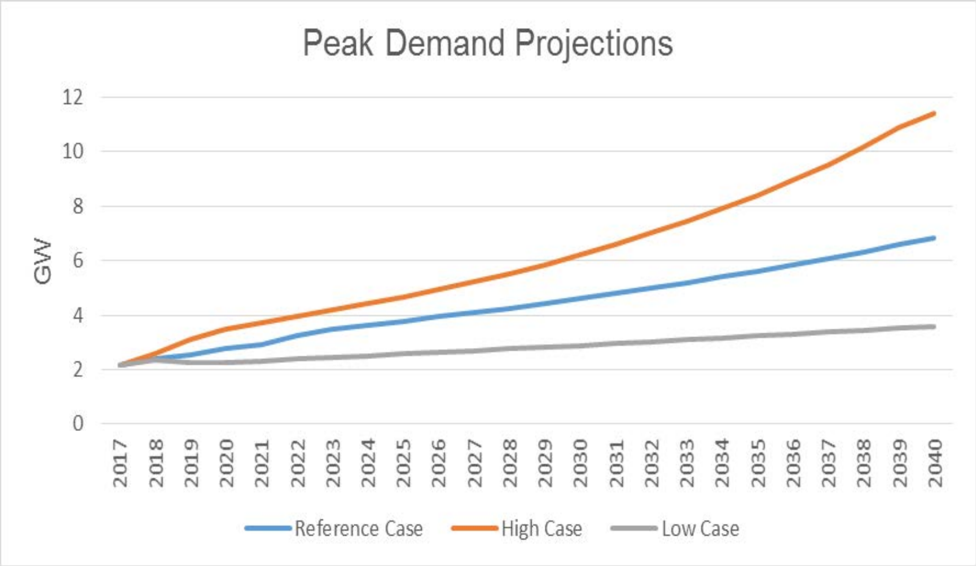


Figure 22: High and Low Total Peak Demand Forecasts



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.

6.3.4. Export Demand Sensitivity

Energy and peak demand projections were estimated for countries neighbouring Ghana, namely Cote d'Ivoire, Burkina Faso, and Togo. 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. Figure 23 illustrates the energy and peak demand forecast of exports used in the Business-As-Usual scenario.

Energy exports are projected to increase steadily in the near term from about 480 GWh in 2017 to about 2,400 GWh in 2035; and is expected to slowly rise to 2,500 GWh in 2040. A similar trend is observed in the peak demand exports, which are expected to rise from about 110 MW in 2017 to about 480 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.

In assessing various demand sensitivities, increased and reduced peak and energy demand export estimates were developed for all three export destinations. Figure 24 and Figure 25 illustrate the high and low export demand estimates, respectively.

Figure 23: Business-as-Usual (BAU) Energy and Peak Demand

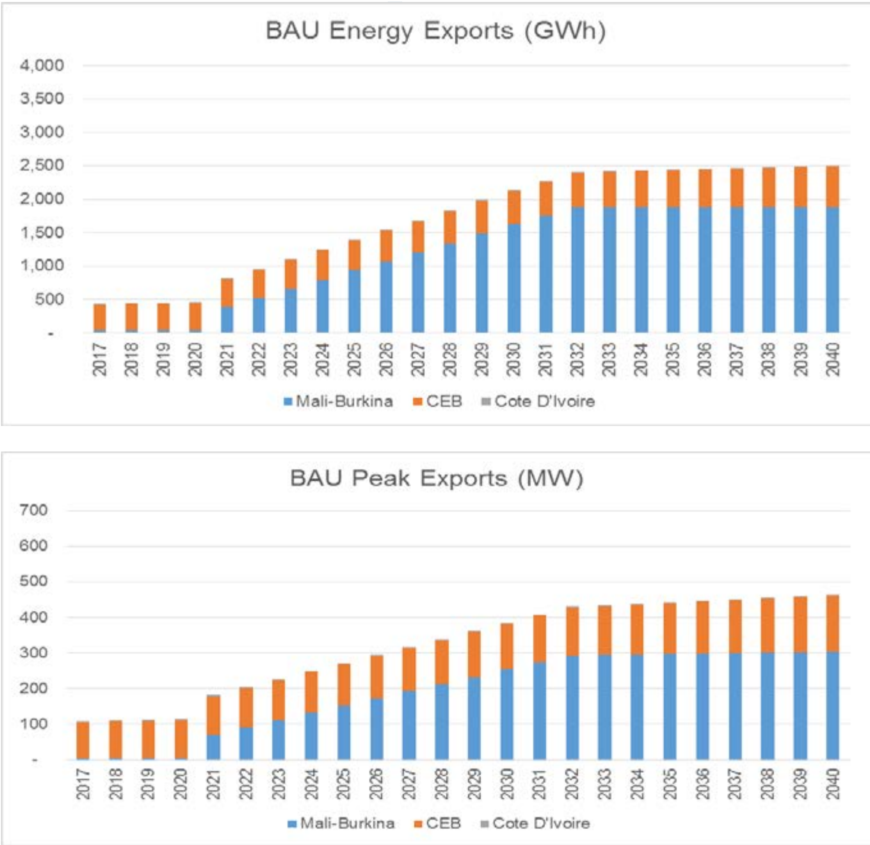


Figure 24: High Export Demand Sensitivity

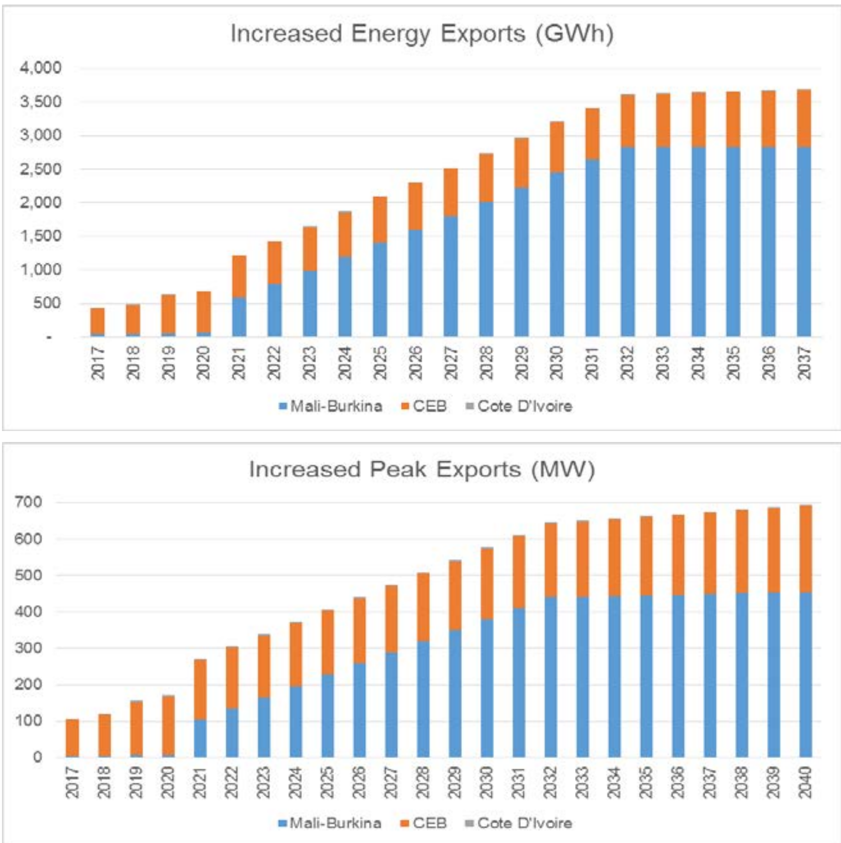
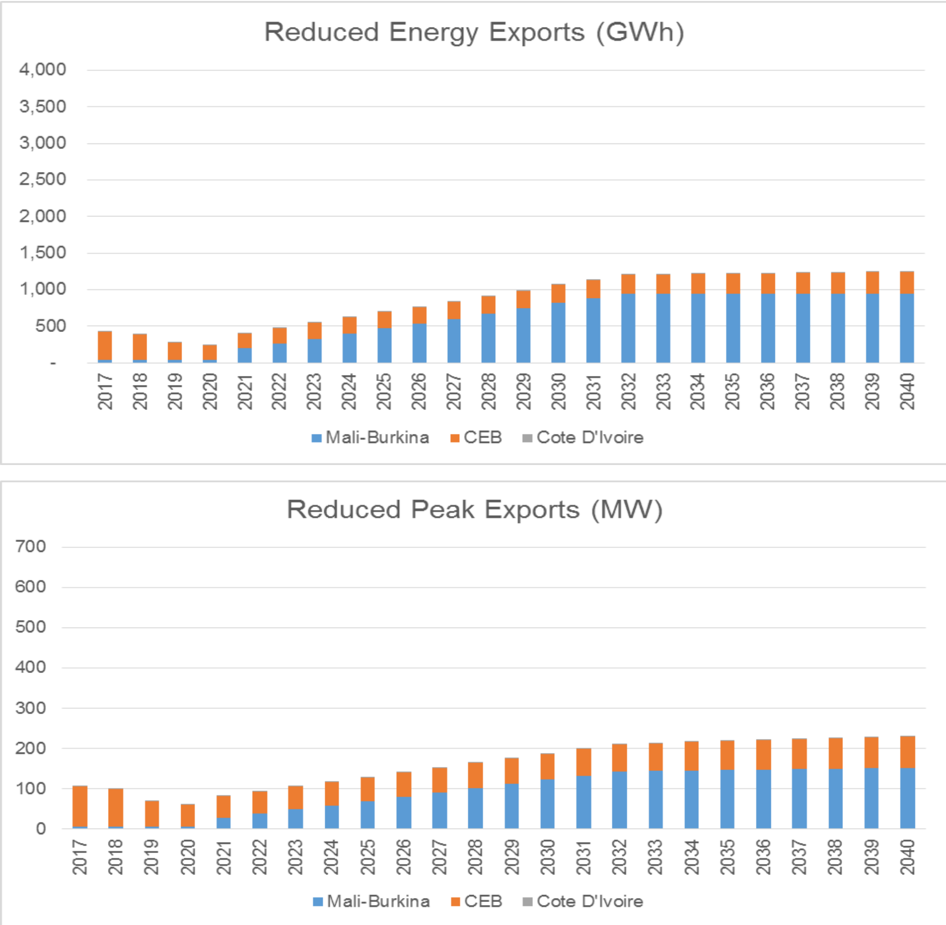


Figure 25: Low Export Demand Sensitivity



6.3.5. Hourly Demand – Load Duration Curves

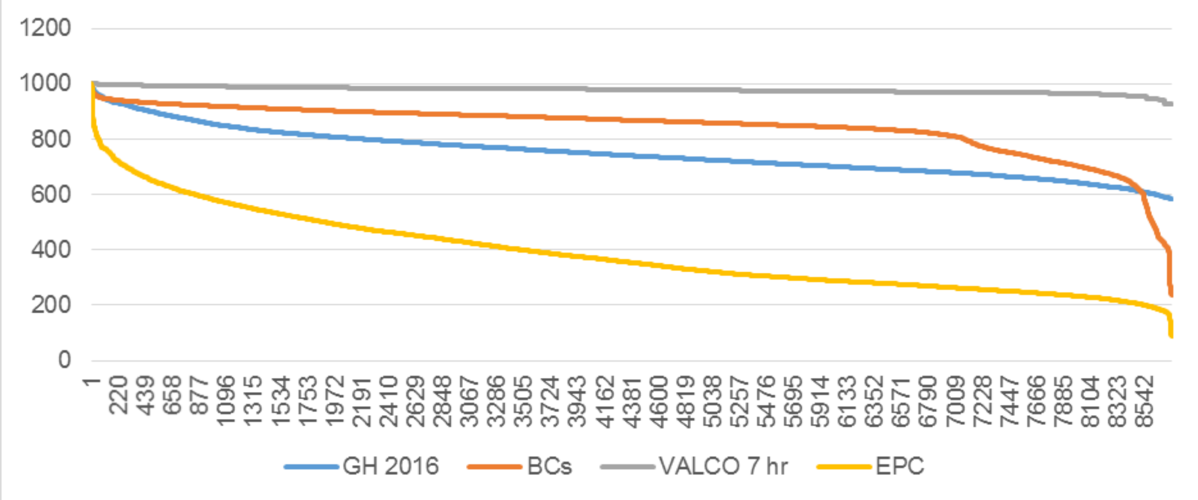
For modelling purposes, IPM utilises a reference year's hourly load duration curve (LDC) to group similar demand and dispatch hours in the optimisation problem (see section 5.4.5). The highest point on the LDC is the peak demand for the year, and the area under the curve is the total energy demand for 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 separately determine the LDCs at a zonal level. Therefore, all the four Ghana zones used a common LDC based on the chronological hourly load data from 2016 for all of Ghana, which was provided by GRIDCo.[55] Similarly, the 2016 hourly demand data for all mining companies was also used as the hourly demand for bulk customers. For VALCo, a 7-day hourly demand data were 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.

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

Figure 26 shows LDCs derived from the hourly data collected. For the *GH-IPM 2018v1*, 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 26: Load Duration Curves scaled to a 1000 MW Peak



Note:

GH 2016 is the load duration curve for the entire Ghana system, based on information form GRIDCo.
BCs is the load duration curve for bulk customers, based on GRIDCo data
VALCO 7 hr is the load duration curve that was used for VALCo for 7 days worth of GRIDCo data
EPC is the load duraction curve for Enclave Power Company (EPC), based on EPC data.

6.3.6. Cost of Unserved Energy

The cost of unserved energy in the *GH-IPM 2018v1* model is based on a 2013 report on ECG System Reliability Assessment. The Study provided estimates of the value of lost load by different types of customers, which is shown in Table 9. These values were used as inputs on the cost of unserved energy for various IPM model regions.

Table 9: Cost of Unserved Energy used in *GH-IPM 2018v1*

	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, updated Ghana-specific surveys are needed to determine the cost of unserved energy that should be used for the modelling.

6.3.7. 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.

(1) Subject to data integrity issues, data used for the load forecasts included the following:
(2) Gross electricity generated, as metered at the generating plants
(3) Net electricity supplied to the grid,[56] as metered by GRIDCo at power plant sites
(4) Electricity purchases, as computed by ECG/NEDCo/EPC/GRIDCo based on metered data at BSPs
(5) Electricity sales, as computed by ECG/NEDCo/EPC/GRIDCo based on metered data at customer sites
(6) Distribution losses: (purchases-sales)/purchases
(7) Transmission losses: (net supply from power plants-purchases)/net supply
(8) 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 sensitivity of sales and data collection problems, among others, should be considered in future analyses.

6.4. Generating Resources

As discussed in the previous chapter, there are three general types of generating units modelled in *GH-IPM 2018v1*:

- “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 2018v1*, firmly planned units were defined as units that were physically under construction as at March 2017.
- “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.

[56] Excludes internal consumption or own plant use.

6.4.1. 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 10. The table shows the total number of generation units at each plant, as well as installed capacity, the net dependable capacity (which is used for the modelling), and the contribution of the plants to the reserve margin. The net dependable capacity is the expected capacity that is available for generation from a planning perspective, although on an operational basis, the amount up to the installed capacity (or greater) can be available for a short duration. The reserve margin capacity is the capacity that is available for meeting the peak demand. In most cases, the dependable capacity is the same as the reserve margin, except for non-dispatchable renewables and plants that are not controlled by the grid operator.

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

Table 11 shows the firmly planned, under-construction power plants in Ghana, as of August 2017.[57] These power plants are expected to come online in 2018 and 2019, although their specific commissioning dates may vary. The Ameri power plant is expected to be transferred to VRA in 2021, as per its build-own-transfer (BOT) contractual arrangement, and therefore from a modelling a perspective, the existing Ameri_2016 power plant will be "retired" in 2021, and immediately the Ameri_2021 plant will take its place.

Table 12 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, the *GH-IPM 2018v1* does not consider economic retirements of existing power plants. So, all plants that do not have firm retirement dates are available to meet energy and peak demand needs throughout the modelling period.

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.

[57] 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.

The existing BXC Solar plant was procured on a feed-in-tariffs (FIT) basis, and the estimated cost of the FIT for this plant is shown as variable costs in $/MWh. The estimated variable cost of the VRA solar plant is also shown in $/MWh.

Table 10: Existing Power Plants in Ghana, as of end of December 2017

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
MRP	Jan-2007	Tema, Greater Accra	3	Volta River Authority	DFO/Gas Combustion	80	70	70
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	Sunon Asogli Power Co.	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
Trojan 1	Sep-2015	Tema, Greater Accra	16	Trojan Power Limited	DFO/Gas Combustion	25	25	25

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 1	Dec-2015	Tema, Greater Accra	13	Karpower Ghana Ltd	HFO/Gas Combined Cycle	247	247	247
BXC Solar	Jan-2016	Winneba, Central	1	BXC Company	Solar Photovoltaic	20	18	0
Ameri_2016	Feb-2016	Takoradi, Western	10	Ameri	Gas Combustion	250	230	230
Trojan 2A	Feb-2016	Kumasi, Ashanti	25	Trojan Power Limited	DFO Combustion	16.3	16.3	16.3
Trojan 2B	Feb-2016	Tema, Greater Accra	25	Trojan Power Limited	DFO Combustion	16.3	16.3	16.3
GP Chirano Plant	Jun-2016	Tarkwa, Western	3	Genser Power	LPG Combustion	33	30	0
Safisana	Sep-2016	Ashaiman, Greater Accra	1	Safisana Company Ltd	MSW – Landfill Gas	0.1	0.1	0
GP Darmang Plant	Dec-2016	Tarkwa, Western	5	Genser Power	LPG Combustion	27.5	25.5	0
GP Tarkwa Plant	Dec-2016	Tarkwa, Western	3	Genser Power	LPG Combustion	35.58	33	0
AKSA	Mar-2017	Tema, Greater Accra	15	AKSA Energy Ghana	HFO/Gas Combined Cycle	375	375	375
SAPP 2	Mar-2017	Tema, Greater Accra	4	Sunon Asogli Power Co.	LCO/Gas Combined Cycle	401	370	370
Total			159			4472	4072	3965

Source: Energy Commission, IRRP Project.

Table 11: 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)
Cenpower	Jan-2018	Tema, Greater Accra	3	Cenpower Generation Company Ltd	LCO/Gas Combined Cycle	340	340	340
Karpowership 2†	Jan-2018	Takoradi, Western	13	Karpower Ghana Ltd	HFO/Gas Combined Cycle	494	450	450
Trojan 3	Jan-2018	Tema, Greater Accra	32	Trojan Power Limited	Gas Combustion	49.9	49.9	49.9
Amandi	Apr-2019	Takoradi, Western	3	AMANDI Energy	LCO/Gas Combined Cycle	194	190	190
Early Power‡	Sep-2019	Tema, Greater Accra	11	Early Power	LPG/Gas Combustion	405.5	377.5	377.5
Ameri_2021*	Feb-2021	Takoradi, Western	10	Volta River Authority	Gas Combustion	250	230	230
Total			72			1733	1637	1637

Source: Energy Commission, PURC, IRRP Project.

† The second Karpowership providing 450 MW of power in Takoradi is expected to replace the first Karpowership of 247 MW in Tema. However, as of January 2018, the second Karpowership is still connected to the grid at Tema, and not at Takoradi. As of June 2018, it is expected that the 450 MW barge will to move to Takarodi and be connected to the grid by August 2018.

‡ The first phase of the Early Power plant is expected to come online using LPG as fuel source in the second quarter of 2018. However, for modelling purposes, the full capacity of the plant is assumed to come online in June 2019. The Early Power plant is experiencing delays in commissioning its first phase, as of July 2018.

* The Ameri_2021 plant is the same as the existing Ameri_2016 plant; however, its ownership is expected to be transferred to VRA in 2021. The operational cost characteristics of this plant are expected to change when the ownership changes. However, this is subject to change based on contract negotiations.

** 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 12: 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%		-	9.2	1.0
Kpong	SouthEastGH	140	2%		-	9.2	1.0
TAPCO (T1)	SouthWestGH	305	15%		7,783	18.7	5.0
TICO (T2)	SouthWestGH	320	15%		7,443	30.9	4.9
MRP	SouthEastGH	70	20%		12,468	12.4	4.5
TT1PP	SouthEastGH	100	8%		11,315	14.3	6.5
TT2PP	SouthEastGH	45	9%		9,720	11.8	4.5
SAPP 1	SouthEastGH	180	9%		9,330	11.8	4.5
VRA Solar	NorthGH	1.8	0%		-	0.0	166.9*
Bui	NorthGH	330	5%		-	27.7	1.6
CENIT	SouthEastGH	100	9%	Mar-2033	12,000	11.8	4.5
Trojan 1	SouthEastGH	25	9%	Sep-2020	8,440	34.0	5.5
KTPP	SouthEastGH	200	7%		10,900	12.3	3.5
Karpowership 1	SouthEastGH	247	10%	Dec-2017	7,640	177.8	3.5
BXC Solar	SouthWestGH	18	0%	Jul-2036	-	0.0	201.8*
Ameri_2016	SouthWestGH	230	10%	Feb-2021	10,160	14.5	5.0
Trojan 2A	AshantiGH	16.3	9%	Feb-2021	8,440	34.0	5.5
Trojan 2B	SouthEastGH	16.3	9%	Feb-2021	8,440	34.0	5.5
GP Chirano Plant	SouthWestGH	30	5%		11,000	17.5	3.5
Safisana	SouthEastGH	0.1	15%		13,500	35.0	4.2
GP Darmang Plant	SouthWestGH	25.5	5%		10,630	17.5	3.5

Plant Name	IPM Ghana Zone	Net Dependable Capacity (MW)	EFOR	Firm Retirement	Heat Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
GP Tarkwa Plant	SouthWestGH	33	5%		9,926	17.5	3.5
AKSA	SouthEastGH	375	7%		8,500	16.0	3.5
SAPP 2	SouthEastGH	370	7%		7,800	16.0	3.5
Cenpower	SouthEastGH	340	7%		7,830	16.0	3.5
Karpowership 2	SouthWestGH	450	5%	Dec-2025	8,514	177.8	3.5
Trojan 3	SouthEastGH	49.9	9%	Dec-2022	8,100	34.0	5.5
Amandi	SouthWestGH	190	12%		8,200	30.9	4.9
Early Power	SouthEastGH	377.5	7%		7,500	16.0	3.5
Ameri_2021	SouthWestGH	230	10%		10,160	14.5	4.2

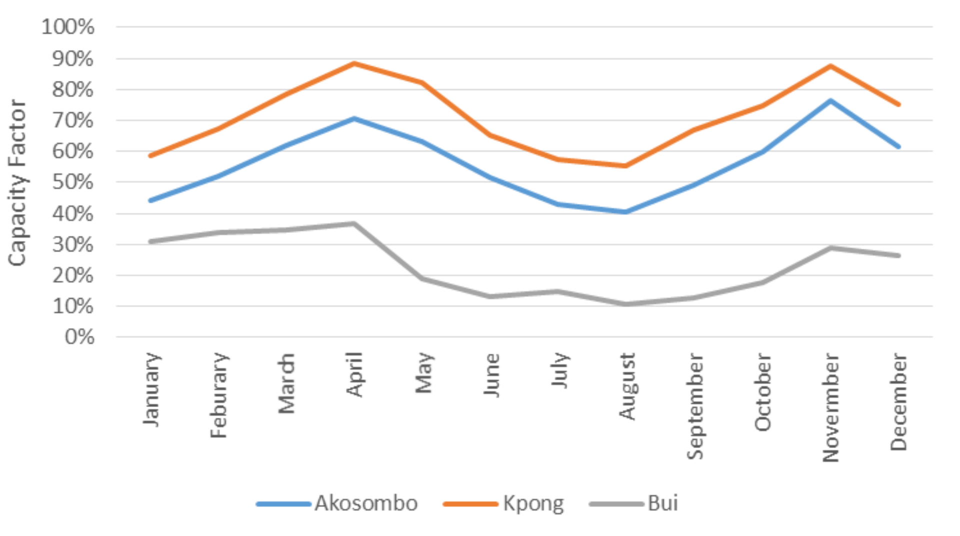
Source: Energy Commission, PURC, VRA, IRRP Project.

*These numbers are based on FiT

Table 13: Annual Capacity Factor Constraints for Selected Power Plants

	Maximum Capacity Factor		
	Akosombo	**Kpong**	**Bui**
2017	46.7%	58.9%	23.2%
2018	46.7%	58.9%	23.2%
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 27: 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 27 and Table 13.

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 13.

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.

6.4.2. 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 14.

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 14, 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 a 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.

Table 14: 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	3.5	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 – 2018	1	1243	1243	24.8		
Solar PV – 2020	1	1020	1020	24.8		
Solar PV – 2026	1	895	895	24.8		
Solar PV – 2035	1	760	760	24.8		
Onshore wind – 2020	2	1437	1547	46.7		
Onshore wind – 2026	2	1356	1460	46.7		
Onshore wind – 2035	2	1249	1344	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. Assumes 5% per year of interest during construction (IDC) for all technologies except solar PV.
3. Heat rate, fixed O&M, and variable O&M were estimated based on EIA 2016.

6.4.3. Capital Cost Sensitivity

The capital cost assumptions shown in Table 14 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.

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 15 shows the various sensitivities considered for renewable energy technologies.

Table 15: Capital Cost Sensitivities for Various Renewable Energy Technologies

Solar PV

Online Year	Unit	Reference	High Cost	Low Cost
2018	USD/kW	1,243	1,243	1,100
2020	USD/kW	1,020	1,020	903
2026	USD/kW	895	1,020	741
2035	USD/kW	760	1,020	608

Solar PV with Storage

Online Year	Unit	Reference	High Cost	Low Cost
2020	USD/kW	1,457	1,821	1,384
2026	USD/kW	1,250	1,562	1,187
2035	USD/kW	1,080	1,350	1,026

Wind

Online Year	Unit	Reference	High Cost	Low Cost
2020	USD/kW	1,547	1,877	970
2026	USD/kW	1,460	1,771	915
2035	USD/kW	1,344	1,671	842

Although conventional thermal technologies are mature, and it is very unlikely costs would decrease, a potential sensitivity where capital costs of these technologies were also decreased (e.g., if these technologies were provided to Ghana at a low cost to support the development of these technologies) was considered. 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%.[58]

6.5. Power System Operations Assumptions

6.5.1. 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 2018v1*, unit specific operational and physical constraints are generally represented through availability and area protection constraints. However, for some unit types, capacity factors

[58] 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).

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 2018v1* used IPM's effective forced outage rate (EFOR) function in specifying availability of the units. Table 12 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. First, we assessed the impact of the loss of two largest thermal units in Ghana. For instance, the loss of one TICO unit with steam, while TAPCO is also out for maintenance. While hydro units could also pose challenges, it is assumed that for the Akosombo hydro plant, only one or more generating units (each rated at 150 MW of net dependable capacity) rather than the hydro entire plant being offline. So, 550 MW (TICO-230 and TAPCO-330) is used to determine the planning reserve margin. This translates in percentage terms of a 2,496MW peak load (highest in 2018) to 22% (550 MW/2496 MW). As the load grows and the system expands with more units coming online, this value in percentage terms will reduce to 20% and lower. The reserve margin computation therefore is assumed to start at 20% in 2018 and to go down further over time to about 15%. The specific reserve margins used in the *GH-IPM 2018.v1* are shown in Table 16.

Table 16: Reserve Margin Assumptions for each of the four GH Zones

Year	Annual RM
2018	20%
2019	19%
2020	18%
2021	17%
2022	16%
2023	15%
2024	15%
2025	15%
↓	↓
2040	15%

Unlike what has been usually done by the various planning agencies so far (e.g., GRIDCo, ECG, EC), the reserve margin assumptions in Table 16 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, the reserve margin requirement in the *GH-IPM 2018v1* model is stronger than if it was enforced for all of Ghana, without considering the transmission constraints.

The contribution of the various power plants to the reserve margin is shown in Table 10 and Table 11, 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 6.6.

Power Plant Lifetimes

The *GH-IPM 2018v1* 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 2018v1* 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 will 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 2018v1* 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 12 and Table 14 respectively.

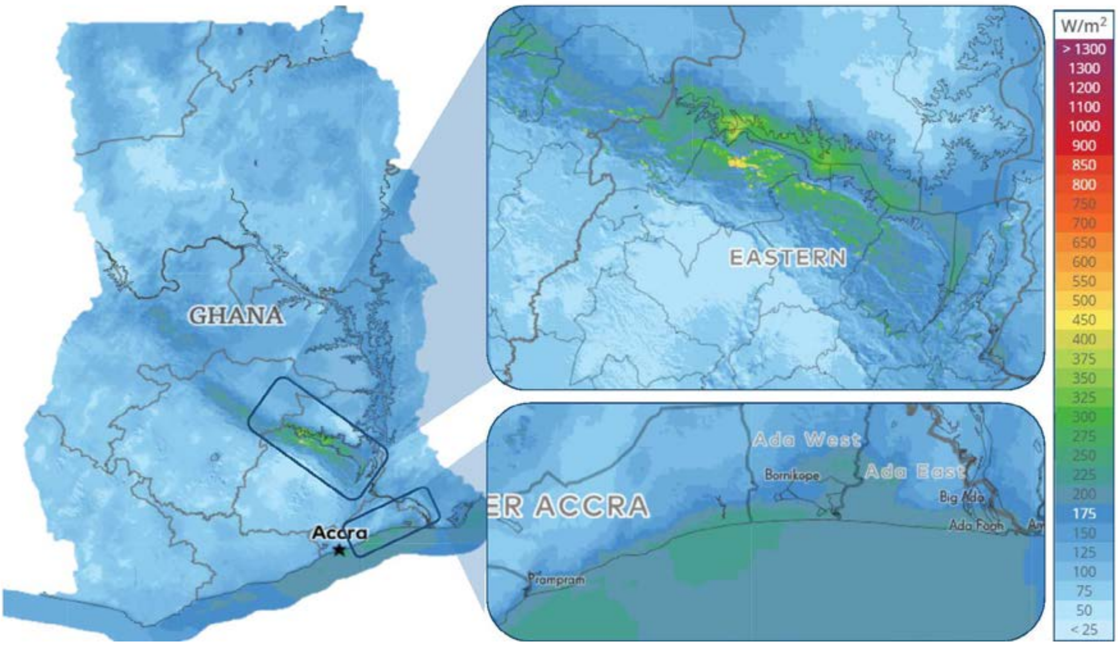
6.6. Renewable Energy Resources

6.6.1. Wind Generation

Wind Resource Potential: This version of the Ghana Model, *GH-IPM 2018v1*, 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 28) 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 2018v1* to reflect the resource availability and the potential operational constraints that is inherent with variable renewable energy resources. As shown in Table 17, the maximum wind capacity limit used as the Reference Case assumption for the *GH-IPM 2018v1* is 550MW. The maximum limit nevertheless was increased to about 950MW in a few strategies (e.g., the Indigenous Resources and the Enhance G-NDC strategies, see Chapter 7).[59] However, a more detailed study to identify specific capacity limits will be beneficial in refining the caps used in the model.

Figure 28: Wind Resource Map – Ghana



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

Table 17: Reference Wind Capacity Limit in the GH-IPM 2018v1

	IPM Model Zone	Maximum Capacity (MW)
Reference Case	SouthEastGH	550

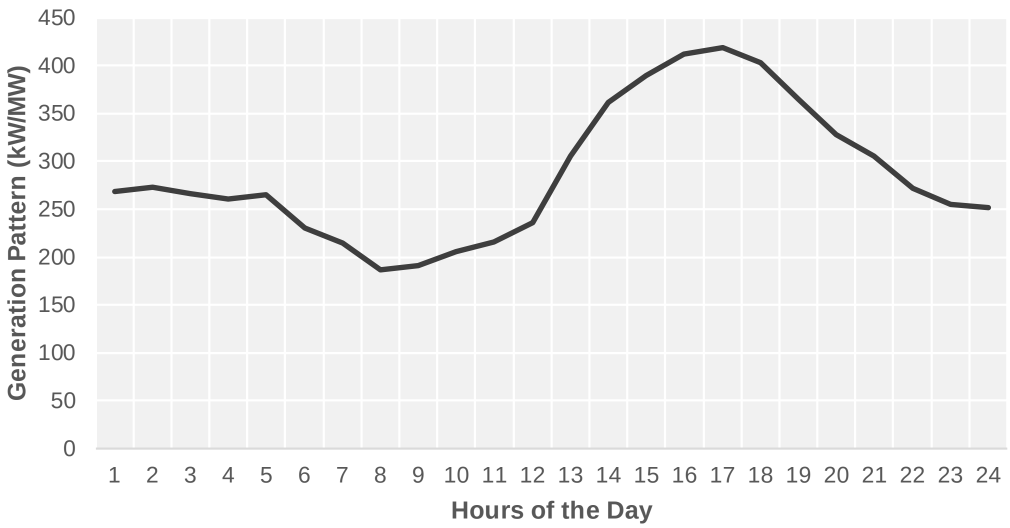
[59] IAEA, Sustainable Electricity Supply Scenarios for West Africa, 2016. https://www-pub.iaea.org/MTCD/Publications/PDF/TE1793web.pdf

High Case	SouthEastGH	950

Generation Profile: Dispatch of wind and solar technologies in IPM are different than the way conventional and other (dispatchable) renewable technologies are dispatched, which is on a pure economic basis, subject to availability constraints. 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 29. 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 10% of its installed capacity to the reserve margin. This was estimated from resource availability during the peak hours.

Figure 29: Typical Wind Generation Profile used in the GH-IPM2018v1.[60]



6.6.2. 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

[60] 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.

not lend itself to the economic use of concentrated solar technology, and therefore, this option was not included in the model.

Similar to the wind, the maximum possible solar photovoltaic capacity is limited in the various zones, mainly due to operational and interconnection constraints. The limits in the reference assumptions are indicated in Table 18. 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. Section G of IPSMP Volume 3 report describes the analysis conducted in 2018 on potential grid impacts of integrating solar PV in the northern region of the country. This analysis was helpful in determining the potential scale of PV that could be integrated into the existing Ghana transmission grid by 2020, and the impacts thereof. The results of the study show that even at penetration levels of 30% of off-peak demand, or 790 MW of solar PV by 2020, the grid is not at risk of reliability criteria violations under steady state conditions. However, the penetration levels are limited by the transient stability of the grid. Under the contingency conditions that were tested, the grid is able to return to a stable state for penetration levels up to approximately 10% of the off-peak demand.

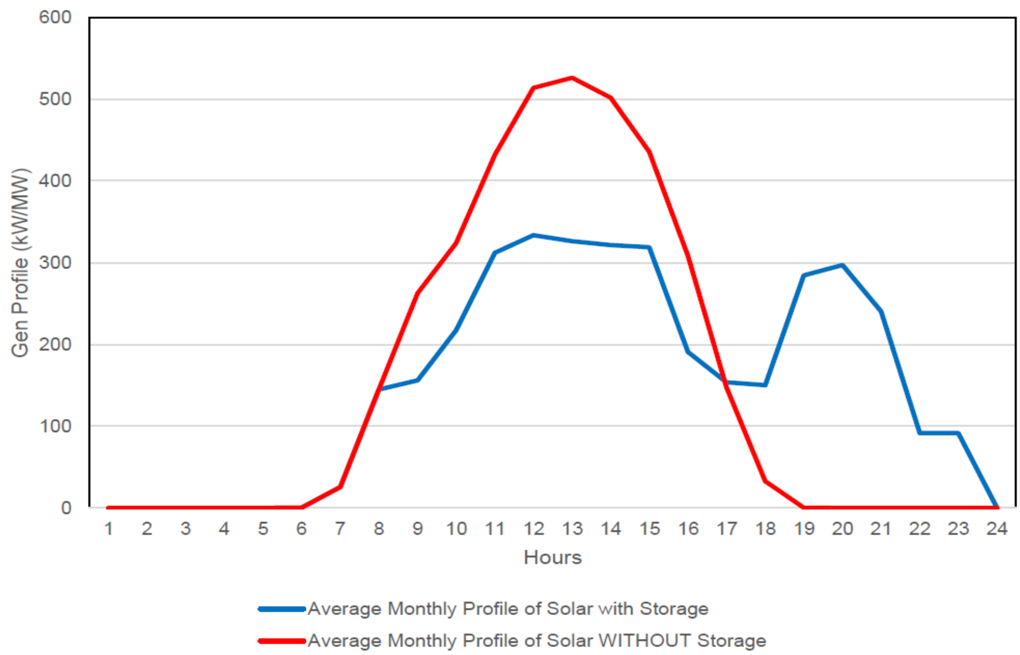
Below is a summary table of the capacity limits for Solar PV and Solar PV with Storage in the *GH-IPM 2018v1*.

Table 18: Reference Solar Photovoltaic Capacity Limit in the GH-IPM 2018v1

	IPM Model Zone	Maximum Capacity (MW)
Solar PV	AshantiGH	110
	NorthGH	925
	SouthEastGH	635
	SouthWestGH	460
Solar PV with Storage	AshantiGH	60
	NorthGH	300
	SouthEastGH	295
	SouthWestGH	215

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

Figure 30: 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.

6.6.3. Dispatchable Renewables

The dispatchable renewable technologies available in the *GH-IPM 2018v1* 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 19 and Table 20 show the biomass capacity and availability constraint included in the model.

The availability of the biomass for power generation is based on a 2016 forecast of the amount of crop waste, wood waste and forest logging residues that was estimated in 2008.[61] The growth rate for crop waste in the future from 2016 onwards was assumed to be 3%, and for the wood waste and forest logging residue at 1.5%. A maximum of 50% of the total waste was assumed to be available for power generation. Biomass is also available from specific plantations that are developed for production. It is estimated that 2,166 MMBtu/year/hectare of biomass can be produced in Ghana. From 2016 to 2024, a maximum of 3000 hectares of

61 https://www.researchgate.net/publication/222514904_A_comprehensive_review_of_biomass_resources_and_biofuels_potential_in_Ghana

https://doi.org/10.1016/j.rser.2010.09.033

land is assumed to be available for plantations, which then increases to 6000 hectares from 2025 onwards. The total biomass availability is then the total of the plantation-based biomass and the waste biomass from crop residue, wood residue, and logging residue. This total is shown in Table 20.

Table 19: Reference Biomass Power Plants Capacity Limits in the GH-IPM 2018v1

	IPM Model Zone	Maximum Capacity (MW)
Biomass	AshantiGH	50
	NorthGH	400
	SouthEastGH	50
	SouthWestGH	40
Biogas	AshantiGH	49
	NorthGH	43
	SouthEastGH	33
	SouthWestGH	27

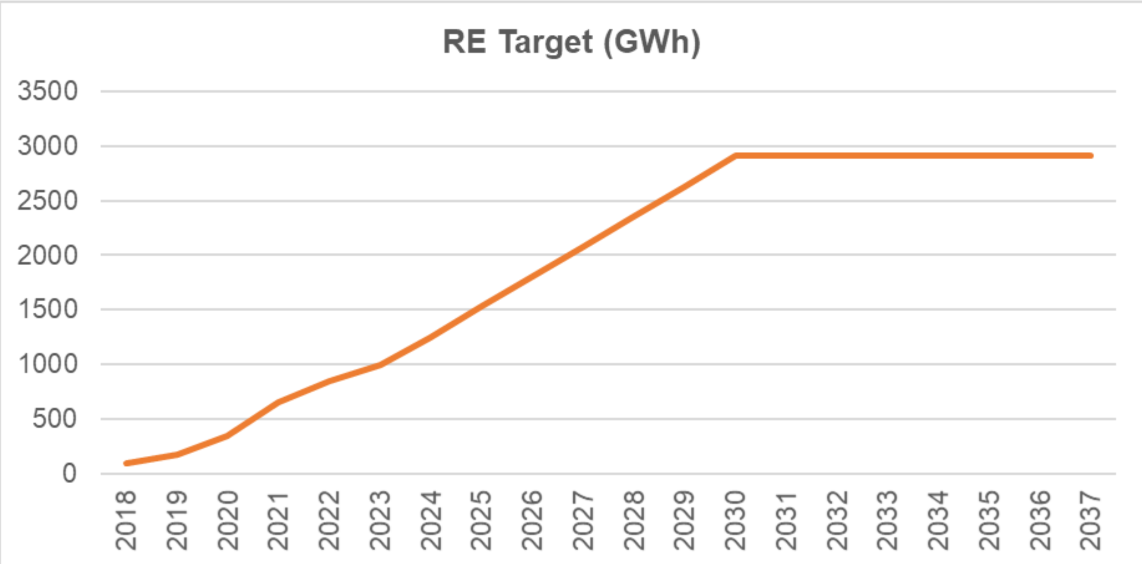
Table 20: Biomass Availability Constraint in the *GH-IPM 2018v1*

Year	Volume (MMBtu)
2016	9,968,459
2017	10,021,212
2018	10,074,777
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

6.6.4. Renewable Energy Penetration Target Option

The Ghana IPM model has the option of building new renewable energy capacity to meet renewable energy penetration targets, if they are called for by policy. In various policy documents and fora, Ghana's Ministry of Energy has called for a renewable energy penetration targets. As such, a specific RE generation target has been developed in the IPM model such that by 2030, at least 10% of the generation is from RE capacity. The trajectory followed for the penetration of renewable energy technologies is as shown in Figure 31. If these targets are chosen in the model, then the renewable energy generation must meet the yearly targets set by the trajectory until 2030 target of 2,900 GWh (10% of total Ghana demand in 2030 (not including exports); see Table 7). RE power plants have to generate sufficient energy to meet the targets as shown below, and new RE plants are built, if necessary, to meet these targets.

Figure 31: Renewable Energy Target Option



As a caveat, electricity supply from roof-top solar PV systems or solar water heaters are not included in this analysis. Even though such systems in principle could contribute met the RE targets, from the model perspective they would effectively reduce the electricity demand on the grid—and as such be included as part of the demand forecasts. Consequently, the renewable energy targets in the IPSMP are only for utility scale renewable energy technologies.

6.6.5. Renewables-based Mini-Grids

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

6.7. Fuel Supply and Price

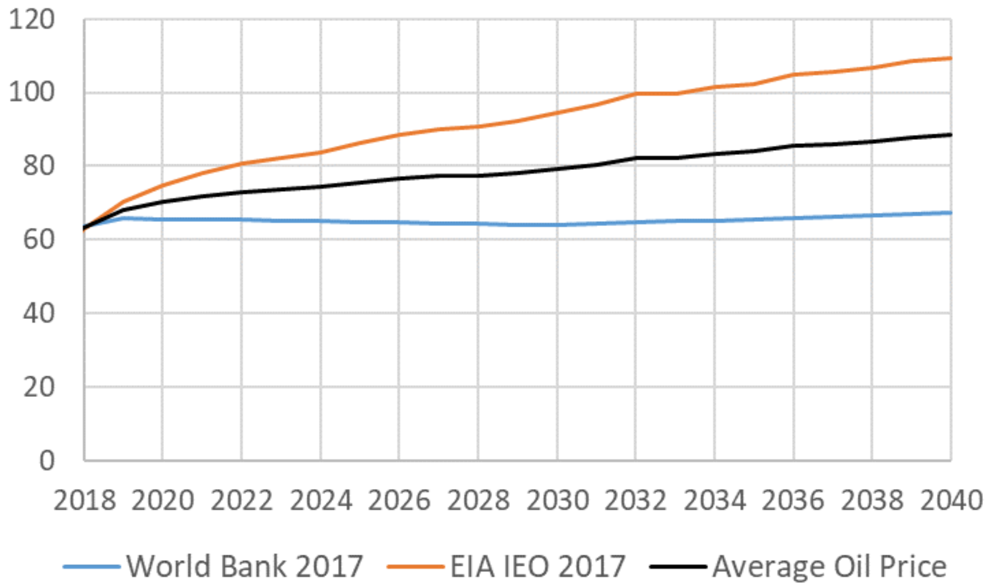
6.7.1. Oil Prices and Availability

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.

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

Figure 32: Crude Oil Price Forecasts ($/bbl) in 2016$

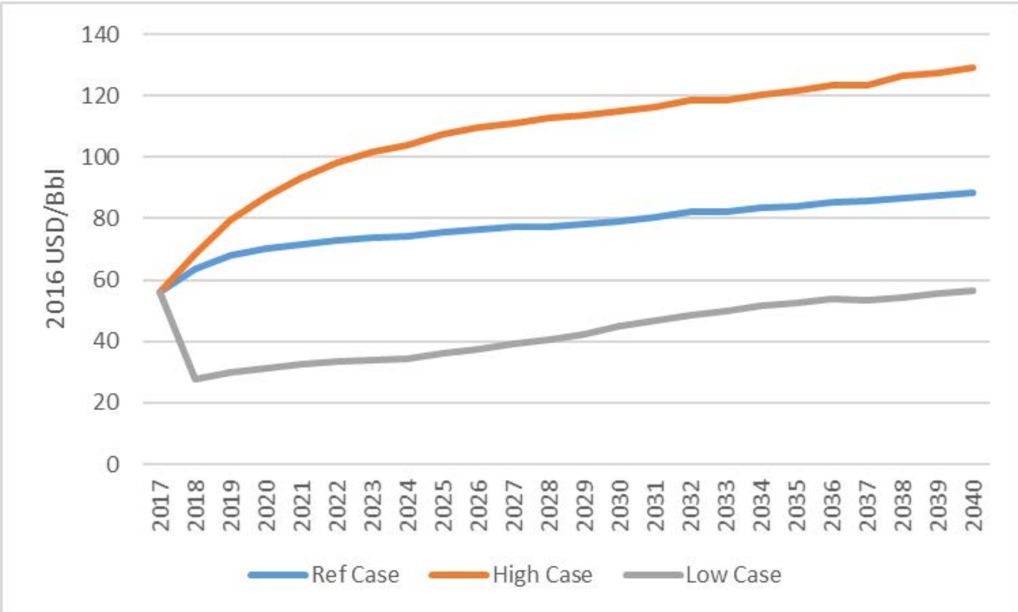


LNG prices are assumed to be linked to crude oil prices, and they are not assumed to decouple from this oil link.

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 33.

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 January 2017 release of Commodities Price Forecasts; the U.S. EIA forecasts were sourced from its 2017 Annual Energy Outlook publication.

Figure 33: Crude Oil Price Sensitivities



6.7.2. 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.

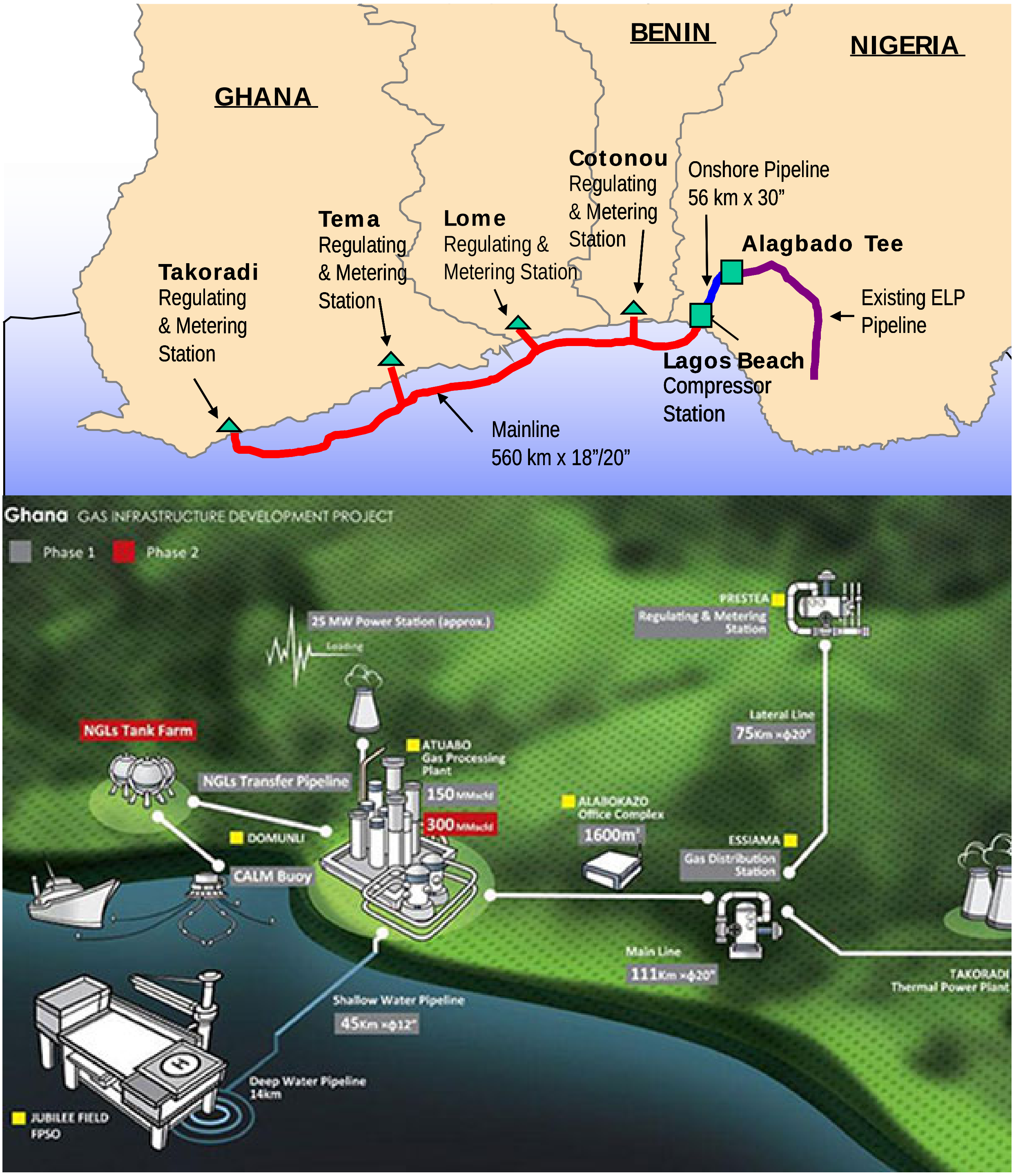
The Nigerian gas is transported from the delta regions of Nigeria via Escravos Lagos Pipeline System to Ikeja in Lagos then through the WAGP to power plants in Tema and Aboadze. The indigenous gas (associated and non-associated) is produced, however, from offshore fields in Ghana. The associated gas is processed onshore at Atuabo, and then delivered to power plants in the Aboadze power enclave. Figure 34 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 21). TAPCO and Sunon Asogli plant were the first plants to have utilised this new gas supply from Nigeria. This supply line was critical to power generation in the country given that Sunon Asogli was a gas-only plant.

However, a number of issues including supply interruption in 2011 to 2012 and gas supply issues in 2013–15, payment issues in 2015–16 resulted in limited gas supply through the

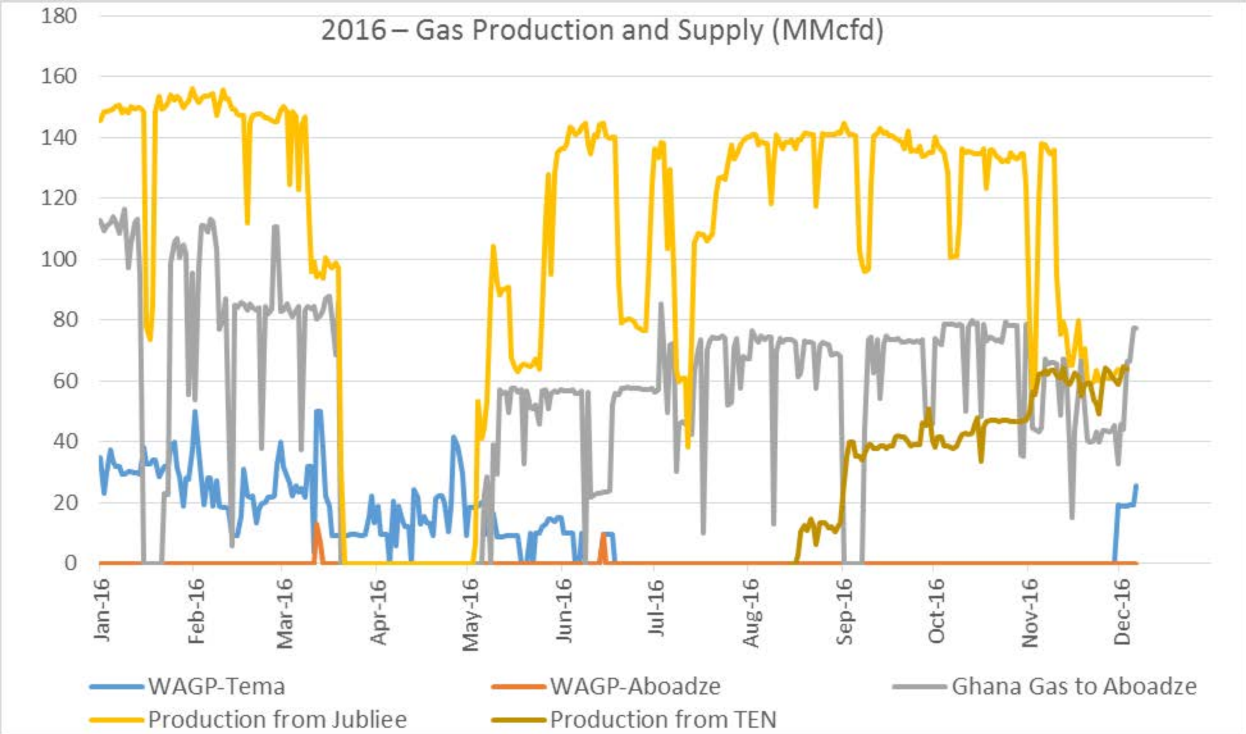
WAGP to power plants in Ghana. WAGP gas supply was effectively cut off for nearly half a year due to non-payment of bills to WAGPCo. WAGP gas was only restored towards the end of 2016, as WAGPCo and the Government of Ghana came to agreement to address the debt issues.

Figure 34: Existing Natural Gas Pipeline Infrastructure for Gas Supply in Ghana



Source: GNPC, WAGP.

Figure 35: Production and Supply of Natural Gas in Ghana in 2016



Source: GRIDCo.

Table 21: 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

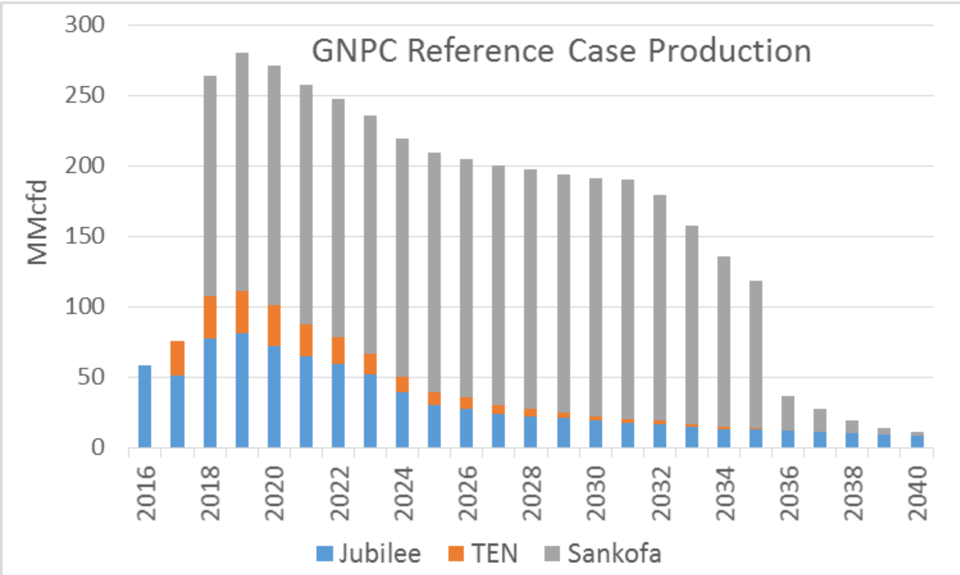
Source: Energy Commission, 2018.

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 35 shows the gas production and supply in 2016, and highlights the number and extent of interruptions to gas supply in Ghana. Figure 35 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. 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 has 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 in early 2017, gas production from the new associated and non-associated fields in Sankofa was expected to deliver gas onshore by Q2 2018, and production from Jubilee and TEN is expected to decline over time, without additional development and production in those fields. Figure 36 shows the expectations of indigenous gas supply, as per GNPC in the early part of 2017. GNPC effectively updated the Reference Case production estimates from these fields from the projections in the Gas Master Plan (GMP). These projections demonstrate that without any other new field development, gas production is expected to decline significantly starting in 2035. However, additional new field development and production will extend further the production of domestic gas.

Figure 36: Average Daily Production Profile for Indigenous Gas in Ghana – Reference Case

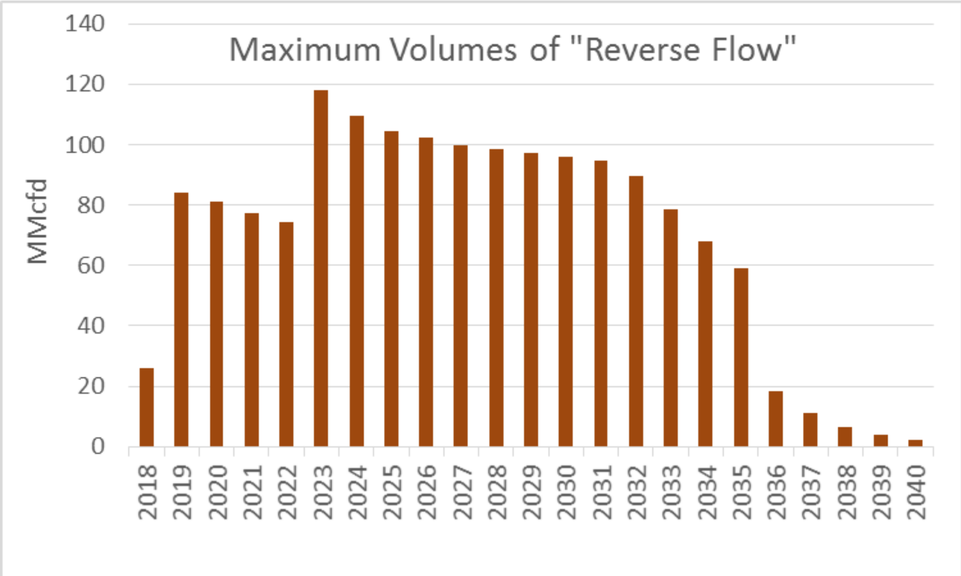


Source: GNPC.

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.

Given the high production volumes expected from Sankofa, and its 90% take-or-pay contractual obligation, the WAGP infrastructure is being currently modified 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 modelled as shown in Figure 37. 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 37: Estimated Maximum Average Daily Volume of Reverse Flow on WAGP



Source: IRRP Project.

For modelling purposes, Nigerian gas through the WAGP was assumed to contribute a maximum of about 30 million cubic feet per day (MMcfd) of daily average gas supply to power plants in Tema, starting in 2020; about 25 MMcfd of daily average gas supply is available in 2018 and 2019.

As noted earlier, LNG is considered as a potential resource for ensuring gas supply reliability, and GNPC as the aggregator is currently considering several LNG regasification proposals. For modelling purposes, LNG supply is being allowed for power plants in both Tema and Aboadze. **However, it is critical recognize that LNG is simply a proxy for the need for additional supply beyond what has been assumed in Figure 36.**

The Southeastern LNG (supporting Tema plants) is expected to have a maximum daily average capacity of about 280 MMcfd of LNG, amounting to about 5 million tonnes per annum of LNG, starting from 2019. A similar-sized Southwest LNG capacity is expected to be available from 2022. LNG availability does not, however, imply that the LNG must be consumed. Instead, the model has the ability to 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 $1.50/MMBtu. This allows for the model to consider potential new-build gas power plants in the Middlebelt area, if it is cost effective.

6.7.3. 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).

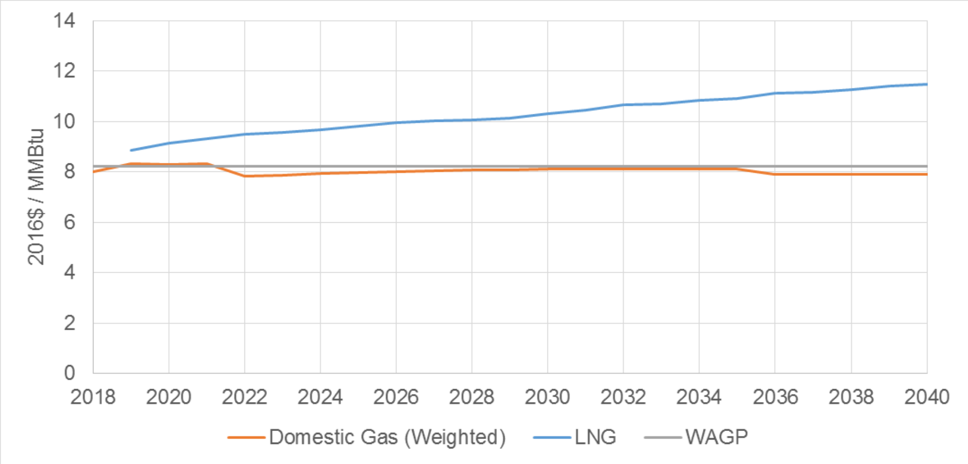
Figure 38 shows the modelled gas prices in the IPM in real 2016$. Each of the different supply points (Jubilee, TEN, and Sankofa) have different prices and midstream (processing and pipeline) costs. The commodity costs for these supply points were determined in discussions with GNPC. The delivered cost 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 assumed to be the same as the foundation gas at $2.96/MMBtu (in 2016$), and the midstream prices for Jubilee gas is assumed to decrease from the current rate of $5.94/MMBtu to $3.79/MMBtu in 2022.[62] This is the reason for the decrease in the weighted average price in 2022 (see Figure 38). TEN gas prices are expected to be much lower than Jubilee, with associated gas assumed to have a cost of $0.50/MMBtu and non-associated gas at $3.00/MMBtu. The midstream costs for TEN and Sankofa are assumed to be $3.79/MMBtu as well.

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 investment cost adjusted price of Sankofa gas is $7.35/MMBtu and the government share is expected to be priced at $2.96/MMBtu (same as Jubilee non-foundation gas). Therefore, the weighted price of Sankofa is assumed to be $6.3/MMBtu, and with the addition of the pipeline transportation costs, the delivered cost of Sankofa is assumed to be $7.76/MMBtu.

Considering the production profiles of the various gas fields (see Figure 36), the weighted average costs of the domestic gas for power plants is determined, as shown in Figure 38.

[62] Based on discussions with GNPC staff.

Figure 38: Delivered Price of Gas to Power Plants Ghana



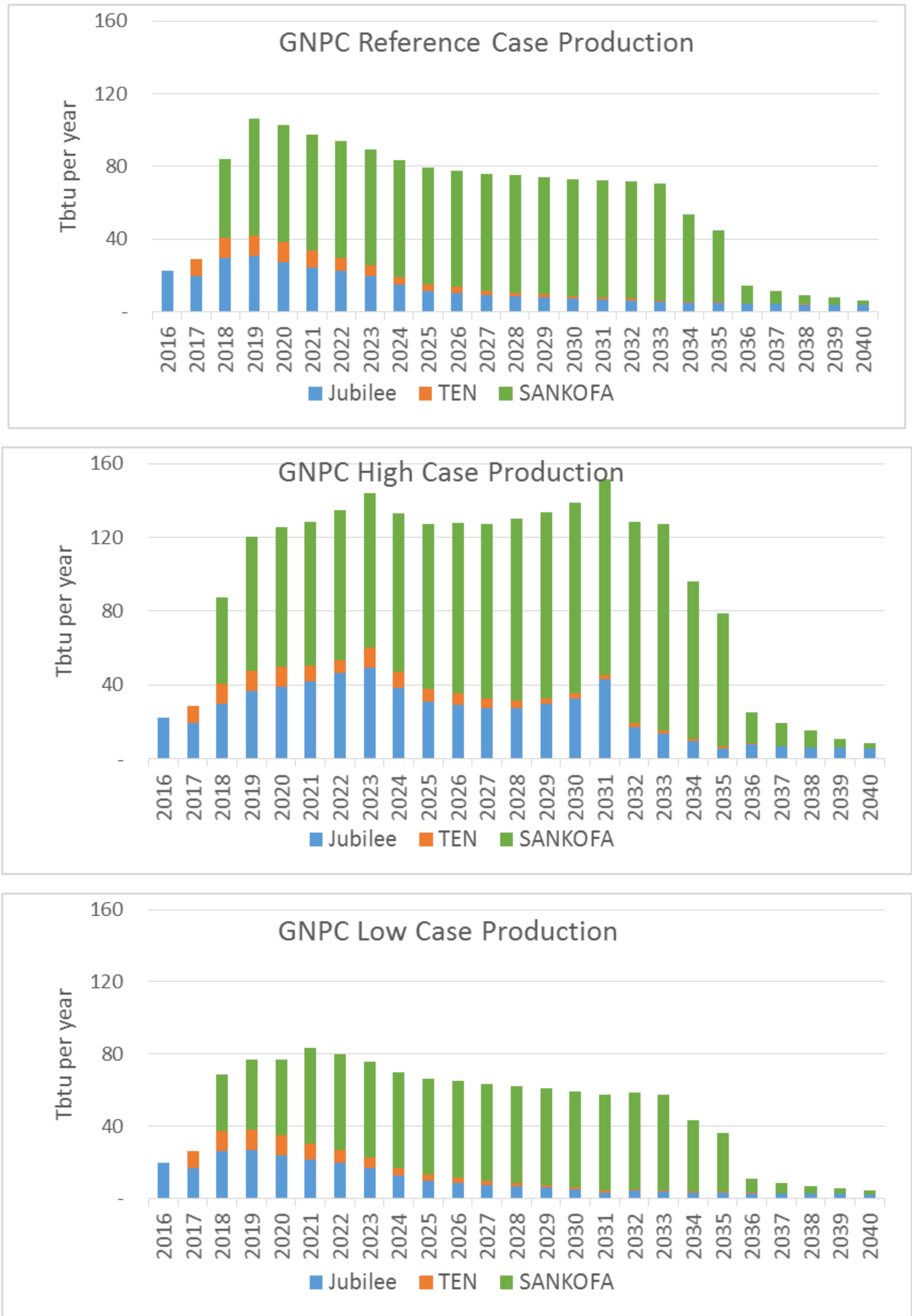
Source: GNPC, IRRP Project.

The cost of WAGP is fixed at $8.2/MMBtu in 2016$ 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 2018 onwards, in line with oil prices.

6.7.4. 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 39.

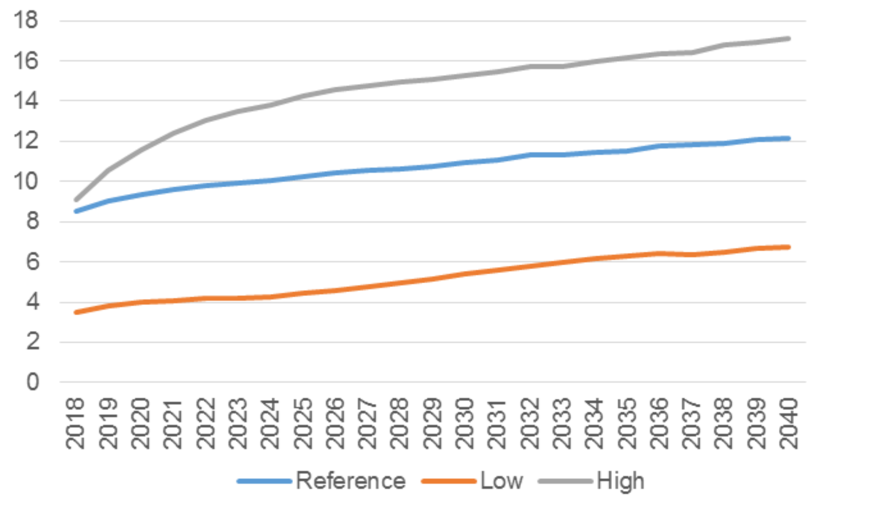
Figure 39: Sensitivity of Domestic Gas Production.



Source: GNPC, IRRP Project.

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 40.

Figure 40: LNG Commodity Prices in 2016$/MMBtu.

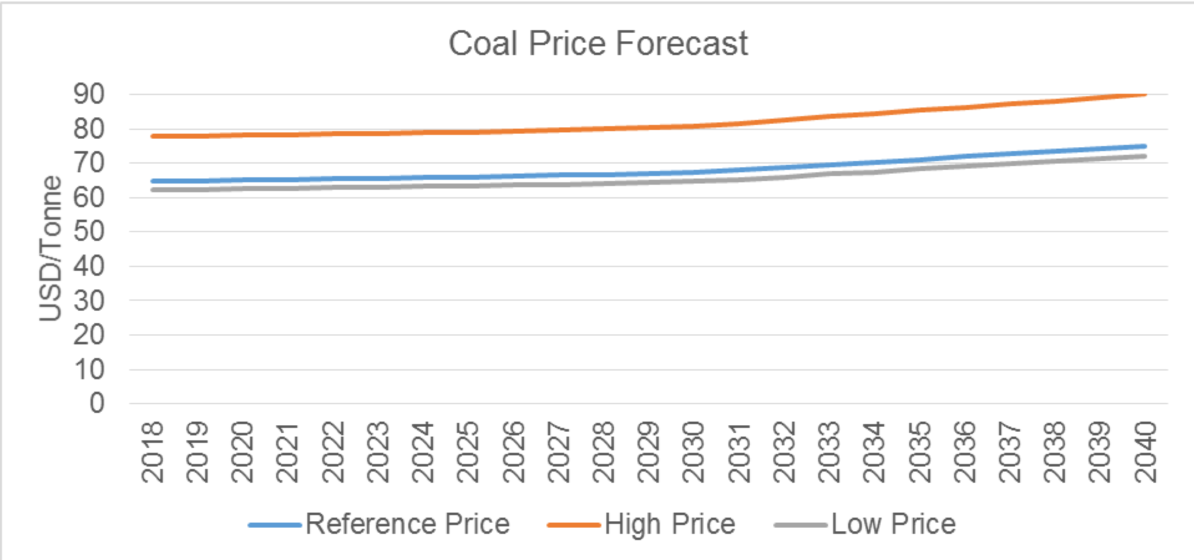


Source: IRRP Project.

6.7.5. 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 14.

Figure 41: South African Coal FOB Price Forecast



Source: IRRP Project.

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 41. Additional costs for insurance, freight, and coal transportation are included separately on top of the free-on-board (FOB) prices.

6.7.6. 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 2018.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.

6.8. 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 42 shows the schematic diagram of the transmission links/corridors between the zones, and Table 22 shows the 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.

Details of the calculations for the TTCs are provided in the Appendices.

Figure 42: Schematic Diagram of the Transmission Paths

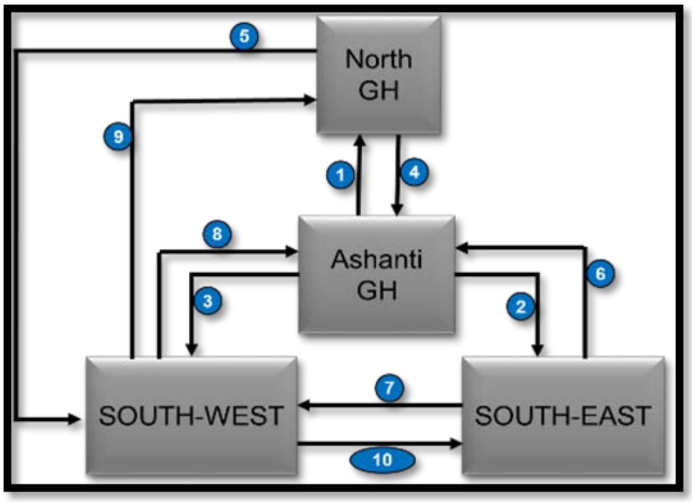


Table 22: Firm and Non-Firm TTCs between Ghana Zones

Link No.	From Ghana Zone	To Ghana Zone	2016–2018		2019–2037	
			Non-Firm TTC	Firm TTC	Non-Firm TTC	Firm TTC
1	AshantiGH	NorthGH	478	0	979	565
2	AshantiGH	SouthEastGH	440	134	440	154
3	AshantiGH	SouthWestGH	344	256	350	256
4	NorthGH	AshantiGH	450	11	450	152
5	NorthGH	SouthWestGH	81	0	81	0
6	SouthEastGH	AshantiGH	140	0	386	121
7	SouthEastGH	SouthWestGH	600	270	623	270
8	SouthWestGH	AshantiGH	643	162	770	410
9	SouthWestGH	NorthGH	10	0	10	0
10	SouthWestGH	SouthEastGH	618	269	649	270

7. 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.

7.1. 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 Business-as-Usual (BAU) 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.

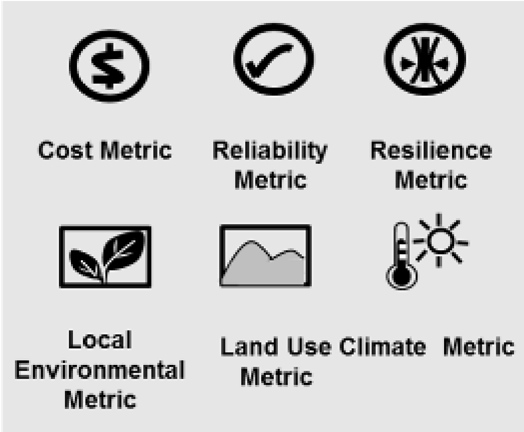
> A **"Least-Regrets" Strategy** is a set of policy objectives for the power sector that performs the best under a broad range of potential techno-economic futures.

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 2018.v1*.

The IRRP team tested each of the build portfolios from these different strategies (including the BAU) 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 particular 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.

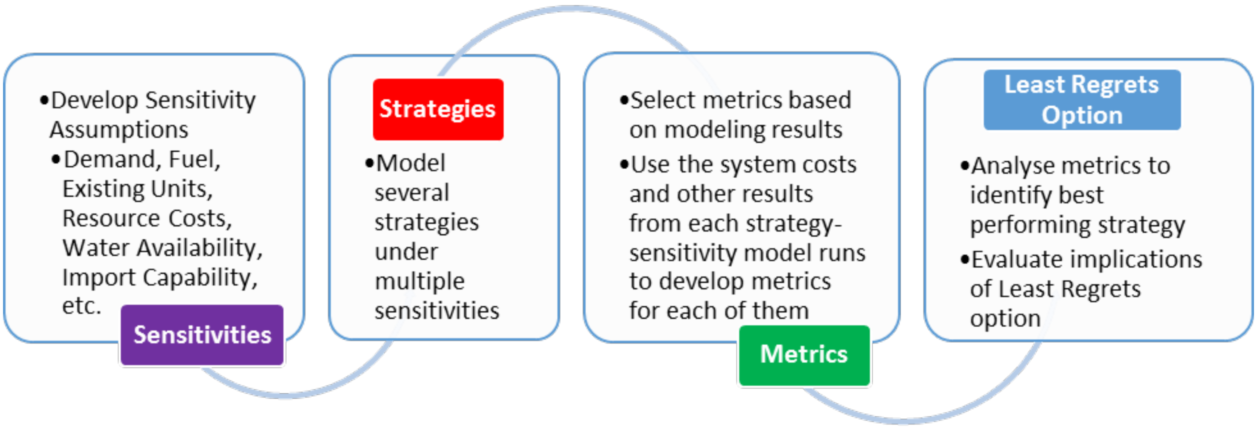


These metrics are then statistically analysed to determine a score for each strategy, and the strategies are then ranked based on their scores.

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 43 summarises the basic methodology used in the identification of the Least-Regrets Portfolio.

Figure 43: Schematic for Identifying Least-Regrets Option for the IPSMP



7.1.1. Strategies

The set of different power sector policies (i.e., strategies) considered for the Ghana power sector are shown in Table 23. 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 23: Strategies Evaluated for IPSMP

#	Strategy Name	Description
I	**Business-as-Usual (BAU)**	• Reference Case assumptions on demand, technology costs, gas resource availability, RE bounds, TTCs, and RE targets • No technology-specific constraints on build options
II	**Indigenous Resources** (Use Indigenous Resources as a high priority, and invest in increasing these resources.)	• Reference Case assumptions on demand, technology costs, TTCs, and RE targets • Higher RE bounds (with additional investments for RE integration) • Build small hydro plants • Build a 60 MW biomass plant • Consume 100% of Sankofa production • High Case natural gas development
III	**Diversified Resources** (Diversify fuel and resource mix.)	• Reference Case assumptions on demand, technology costs, gas resource availability, RE bounds, TTCs, and RE targets • Build coal, nuclear, biomass, and biogas plants
IV	**Enhanced G-NDC*** (Reduce the growth of CO_2 emissions.)	• Reference Case assumptions on demand, technology costs, gas resource availability, TTCs, and RE targets • Constrain CO_2 emissions from the power generation to half of the BAU emissions after 2020 • High RE bounds
V	**Export-Oriented** (Increase exports to neighbouring countries.)	• Reference Case assumptions on domestic and VALCO demand, technology costs, gas resource availability, and RE targets • No technology-specific constraints on build options

*G-NDC refers to Ghana Nationally Determined Contributions, which are Ghana's commitments under the Paris Agreement (see Table 46 in Section 12.2).

7.1.2. 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, 13 sensitivities were considered under five categories, as indicated in Table 24. 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, #10, #11). 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 24 describes the sensitivities.

Table 24: 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 coal, LNG, domestic gas, and liquid fuel prices, relative to Reference Case
4	Low Fuel Prices	• Lower coal, LNG, domestic gas, and liquid fuel prices, relative to Reference Case
5	Limited Gas Supply	• No LNG availability and GNPC low case production
6	Greater Domestic Fuel Supply	• LNG supply is as per the Reference Case, GNPC High Case production, and gas pipeline expanded to NorthGH by 2025
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 small hydro, solar, wind, and biomass plants, relative to the Reference Case
9	Lower RE Capital Costs	• Lower capital costs for small hydro, solar, wind, and biomass plants, relative to the Reference Case
10	High Demand, High Fuel Cost, Limited Water Inflows, and Higher RE Costs	• High Case demand, with high fuel prices (coal, oil, gas), GNPC low case production, no LNG availability, limited water inflows due to climate change, and higher RE capital costs
11	Low Demand, High Fuel Cost, Limited Water Inflows, and Higher RE Costs	• Low case demand, with high fuel prices (coal, oil, gas), GNPC low case production, no LNG availability, limited water inflows due to climate change, and higher RE capital costs
12	Lower RE Capital Cost, Higher Fuel Prices	• High oil and gas prices, but lower RE capital costs
13	Lower Capital Cost for Conventional Resources	• Capital costs for conventional technologies (CCs, CTs, nuclear, and coal) lower than expected

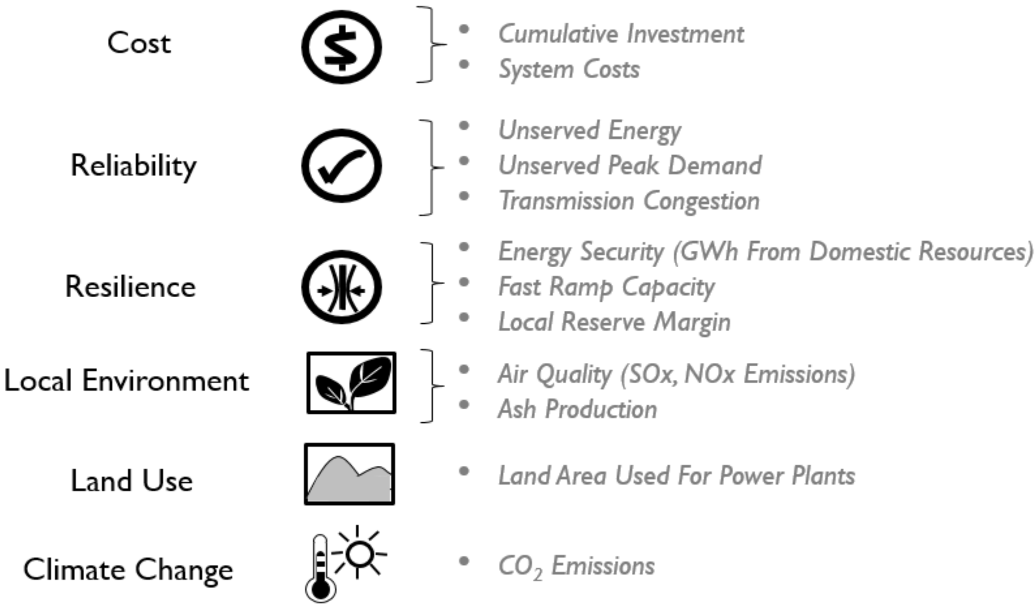
These sensitivities will depend on the expectations of future risks, and so they will be different for the future updates of the IPSMP.

7.1.3. 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, 12 metrics were selected in six different categories: cost, reliability, resilience, local environment, land use, and climate. Figure 44 shows a breakdown of the main categories of metrics into sub-metrics.

Figure 44: 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 25.

Table 25: 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 energy**	GWh	Cumulative sum of GWh of energy not served
	Meeting growing demand	**Unserved peak**	MW	Cumulative sum of MW not served of total peak demand
Resilience	Increase resilience	**Fast start/ramp generation available**	Ratio	Ratio of variable RE to fast-ramp capacity available
Resilience / Reliability	Increase resilience (energy security)	**Energy (GWh) produced using domestic resources**	%	% of GWh produced from domestic resources, including RE
Resilience / Reliability	Increase resilience	**Local reserve**	MW	Capacity of local reserve available 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

For each supply strategy-sensitivity combination, these metrics were calculated over the 10-year (2018–2027) and the 20-year (2018–2037) modelling periods. For each strategy, the average was then calculated over the entire range of sensitivities for each metric.

7.2. 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 45 illustrates the simple supply-demand balance chart that shows 2017 and 2019 net generation from existing and under-construction plants along with the projected energy forecast up until 2037. The plants under construction are all earmarked to come online at the latest by 2019 and will cumulatively add about 1200 MW of installed capacity to the grid. They are Trojan 3, Karpowership 2, Cenpower, Amandi, and Early Power. The simple analysis shows that additional capacity is only needed by the late 2020s, under the reference demand forecast.

Although it is a rather simplistic approach to assessing the supply-demand balance, it still clearly shows the need for additional generation capacity 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 resources to be developed earlier than indicated by the simple analysis seen in Figure 45.

Figure 45: Supply-Demand Balance in Ghana

The subsections below discuss the capacity expansion plans for the various strategies discussed in section 7.1.1. 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 26 and Table 27.

Table 26: Summary of Generating Capacity Additions (MW) for the 10-Year and 20-Year Periods

	BAU		Indigenous Resources		Diversified Resource		Enhanced G-NDC		Export-Oriented	
Capacity Type	**2018–27**	**2028–37**	**2018–27**	**2028–37**	**2018–27**	**2028–37**	**2018–27**	**2028–37**	**2018–27**	**2028–37**
Oil/Gas Combined Cycle	0	700	40	1600	0	0	265	685	0	855
Gas Combustion Turbine	0	0	0	0	0	0	0	0	0	0
Biomass Combustion	0	0	60	0	60	0	95	0	0	0
Oil Combustion	0	0	0	0	0	0	0	0	0	0
Oil/Gas Combustion	0	0	0	0	0	0	0	0	0	0
Hydro	60	0	80	0	0	0	55	0	60	0
Solar PV*	560	730	345	730	475	635	1095	1460	560	730
Solar PV + Storage	0	185	0	0	0	60	190	140	0	185
Coal Steam Turbine	455	550	0	0	485	570	115	0	480	590
Wind	300	250	445	500	300	250	450	500	300	250
Nuclear	0	0	0	0	0	1000	0	460	0	0
Biogas	0	0	0	0	5	0	0	0	0	0
Conventional Thermal	455	1250	40	1600	485	1570	380	1145	480	1445
% RE	67%	48%	96%	43%	63%	38%	83%	65%	66%	45%
TOTAL	**1375**	**2415**	**970**	**2830**	**1325**	**2515**	**2265**	**3245**	**1400**	**2610**

Notes: * The solar PV penetration shown here is consistent with the analysis conducted in 2018 (see section G of IPSMP Volume 3) indicating that under steady-state conditions, Ghana's 2020 grid is not at risk of reliability criteria violations, even at penetration levels of 30% of off-peak demand, or 790 MW of solar PV. However, the transient stability and contingency analysis indicates that solar PV up to 10-15% of off-peak demand is reasonable.

Table 27: Total Generation (GWh) at the End of the 10-Year and 20-Year Periods

	Current	BAU		Indigenous Resources		Diversified Resource		Enhanced G-NDC		Export-Oriented	
Capacity Type	**2017**	**2027***	**2037***	**2027***	**2037***	**2027***	**2037***	**2027***	**2037***	**2027***	**2037***
Oil/Gas Combined Cycle	8,260	12,070	17,330	14,740	23,810	11,690	8,760	12,560	16,590	12,620	18,040
Gas Combustion Turbine	420	-	20	100	10	-	-	-	-	-	20
Biomass Combustion	-	-	-	450	450	450	450	710	710	-	-
Oil Combustion	60	-	-	-	-	-	-	-	-	-	-
Oil/Gas Combustion	80	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080	3,080
Hydro	5,070	6,190	6,190	6,270	6,270	5,980	5,980	6,190	6,190	6,190	6,190
Solar PV	30	790	1,760	520	1,540	680	1,530	1,510	3,460	790	1,760
Solar PV + storage	-	-	230	-	-	-	80	240	420	-	230
Coal Steam Turbine	-	3,370	7,460	-	-	3,590	7,850	860	860	3,590	7,970
Wind	-	700	1,280	1,040	2,210	700	1,280	1,050	2,220	700	1,280
Nuclear	-	-	-	-	-	-	8,320	-	3,830	-	-
Biogas	-	-	-	-	-	40	40	-	-	-	-
Conventional Thermal	8,820	18,520	27,890	17,920	26,900	18,360	28,010	16,500	24,360	19,290	29,110
Renewable (w/L. Hydro)	5,100	7,680	9,460	8,280	10,470	7,850	9,360	9,700	13,000	7,680	9,460
Renewable (w/o L. Hydro)	30	1,710	3,500	2,310	4,490	1,870	3,380	3,730	7,010	1,710	3,500
% RE (w/o Small Hydro)	0.2%	6.5%	9.4%	8.8%	12.0%	7.1%	9.0%	14.2%	18.8%	6.3%	9.1%
TOTAL	**13,920**	**26,200**	**37,350**	**26,200**	**37,370**	**26,210**	**37,370**	**26,200**	**37,360**	**26,970**	**38,570**

*Note that due to the mapped year approach using the IPM modelling, 2027 is represented by the run year 2026, and 2037 is represented by the run year 2035.

7.2.1. Business-as-Usual (BAU) Strategy

Generation Capacity

The BAU Strategy does not have any specific technology constraints, as indicated in Table 23. 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. New renewable power plants are only needed in the short term primarily to meet the 10% RE generation target by 2030.

Hence, the results indicate that up to 2027, the additional capacity required for generation will be primarily dominated by new renewables, which accounts for about 67% of the total additional capacity added by the mid-2020s.

Large thermal power plants, such as coal or gas-fired plants, need to be only added to the generation mix by the mid-2020s. In the Reference Case assumption, indigenous natural gas volumes are limited by the expected production (see Figure 36 in Section 6.7.2) and the prices of additional gas from LNG are increasing over time (see Figure 40 in Section 6.7.4). As such, the model decides to build a coal plant of about 455 MW in the SouthWestGH zone in 2025. An additional 550 MW of coal-based generation would be built in the late 2020s and gas-fired combined cycle plants (CCs) are only selected in the late 2030s. Figure 46 shows the new generation capacity addition required in the BAU Strategy. It also shows that some plants retire in the early to mid-2020s and also in the early 2030s. The retirement of these plants only reflects current contractual retirement arrangements since IPM's economic retrofits and retirements functionality was not yet implemented in this version of the model (*GH-IPM 2018v1*). Table 28 is a list of the specific power plants with their respective online and firm retirement dates as input in the model.

Table 28: Contractual Firm Power Plant Retirement Dates in *GH-IPM 2018v1*

Plant Name	Online Date	Firm Retirement Date
CENIT	03/10/2013	10/03/2033
Trojan 1	10/09/2015	10/09/2020
KarpowerShip 1	14/12/2015	30/04/2017
BXC Solar	15/01/2016	15/07/2036
Ameri_2016	01/02/2016	01/02/2021
Trojan 2A	15/02/2016	15/02/2021
Trojan 2B	15/02/2016	15/02/2021
KarpowerShip 2	01/01/2018	31/12/2025
Trojan 3	01/01/2018	31/12/2022

As shown in Figure 47, the existing hydro and oil and gas units will continue to significantly contribute to the generation of electricity and, by 2027, existing units would contribute about 21 TWh annually. As new units are built, they begin to steadily increase their contribution to generation and by the end of the 10-year period in 2027, the new builds contribute about 5 TWh, which increases to 16 TWh by the end of the 20-year planning period— representing almost 45% of the total generation in that period.

Figure 46: Capacity Additions for Business-as-Usual Strategy

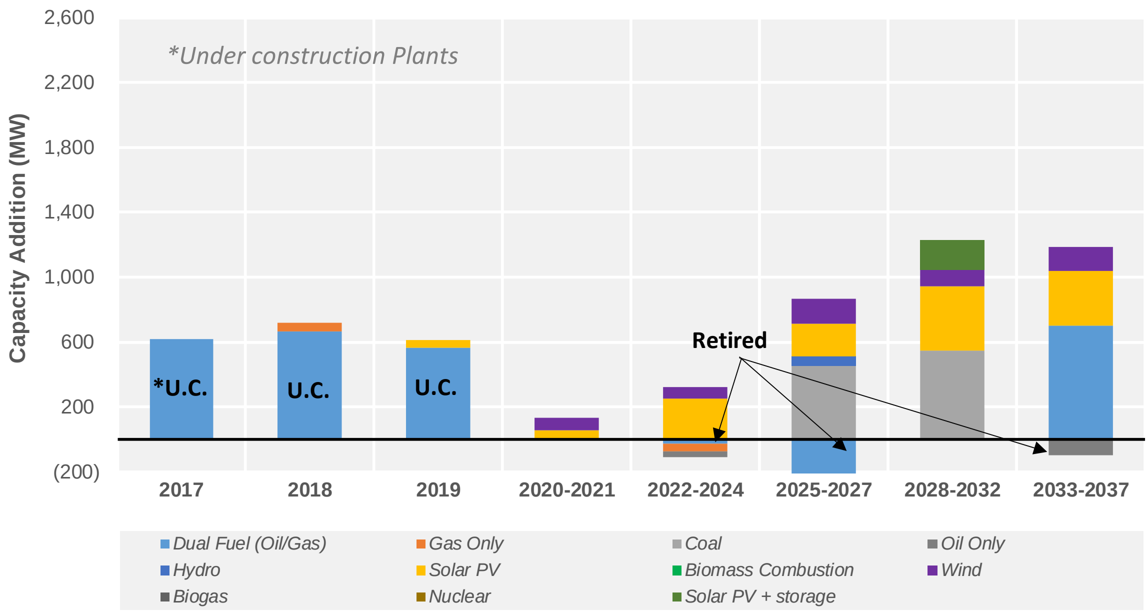
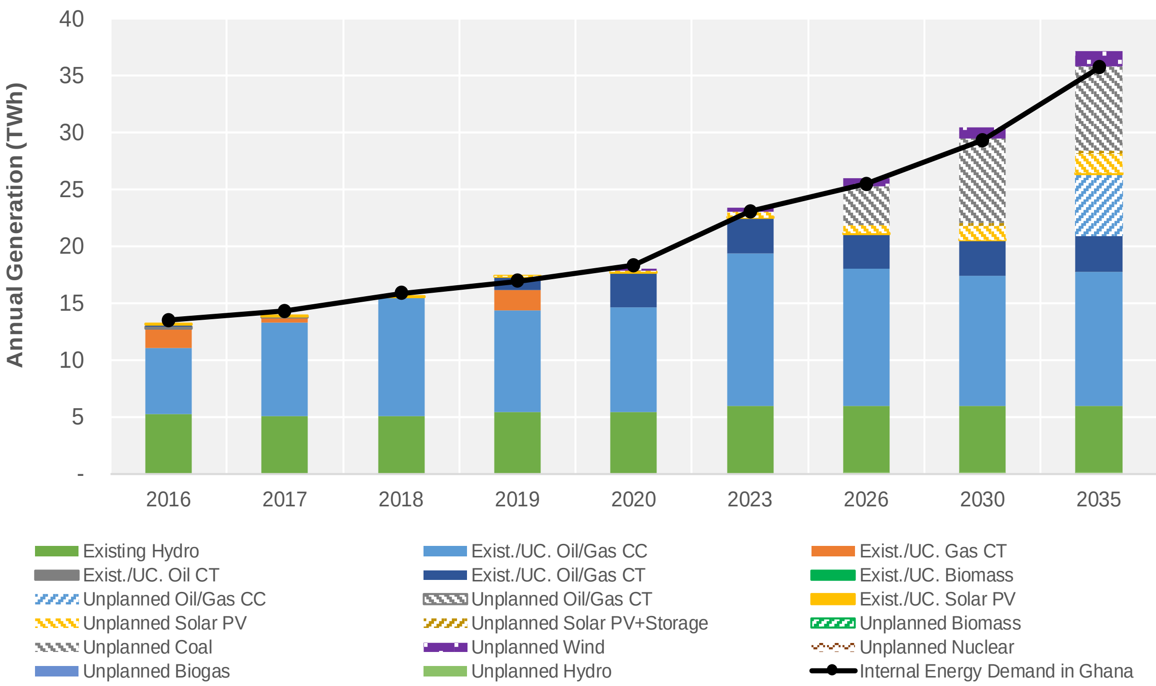


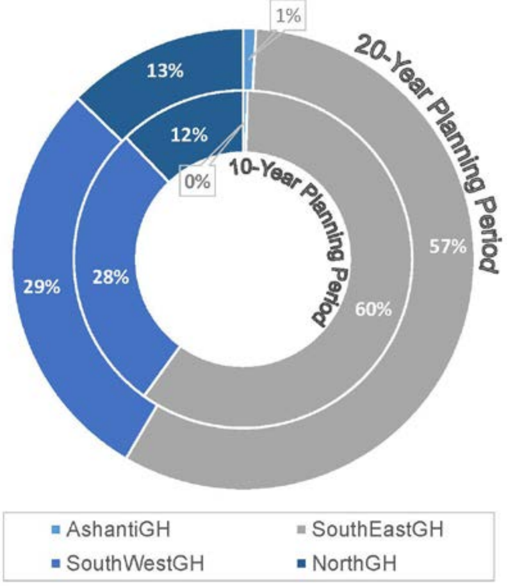
Figure 47: Annual Generation Profile for Business-as-Usual Strategy



The SouthEast GH zone has the highest share of installed generation capacity in the Ghana zones as shown in Figure 48. By the end of the 10-year period, the share of total installed capacity in the zone is about 60%. It decreases, however, to 57% in the 20-year period (longer term) due to the addition of more plants in the SouthWestGH—primarily, an additional 550 MW of coal and the over 400 MW of solar PV plants in the early to mid-2030s. This increases the share of installed capacity in the SouthWestGH from 28% in the 10-year period to 29% in the longer term. The North also sees a slight 1% increase in the share of installed capacity due to the addition of solar PV plants in the longer term.

The Middlebelt has less than 1% of the share of installed capacity both in the 10-year and 20-year period. By the end of the 10-year period it has only 25 MW of solar PV. The only existing generating capacity in this zone, the Trojan 2A plant, retires in the early 2020s. Beyond 2027, the capacity in this zone increases to 75 MW (solar PV)—although most of it does not contribute to reserve margin, unless it has some associated battery storage.

Figure 48: Distribution of Installed Capacity by Zones for BAU



Fuel Consumption

As shown in Figure 49, natural gas is the primary fuel consumed in this strategy in the early years up until the mid-2020s when coal comes online. Domestic gas takes a larger share of the volume, until early the 2020s when more gas is needed to make up for the limited domestic gas volumes (see Figure 36 in section 6.7.2). Liquid natural gas (LNG) in the Tema region is consumed starting by the mid-2020s; however, LNG is simply a proxy for additional gas needs, which can be met by additional domestic gas supply and/or WAGP supplies.

The total annual volume of natural gas needed by the end of the 10-year period is about 117 TBtu per year. In the BAU Strategy, gas consumption declines subsequently, however, due to the coal plant coming online and goes back up in the early 2030s as demand grows and the need for more generation from combined cycle plants increases. By the end of the 20-year planning period (2037), natural gas requirements rises to about 155 TBtu per year as shown in Figure 50.

Consumption of coal commences in the mid-2020s, when the 455 MW coal plant comes online, and an additional 550 MW is added on in the early 2030s. This sees a rise in the yearly coal consumption from about 700 million tonnes (Mt; 30 TBtu) in 2027 to about 1,500 Mt by 2037.

Transmission Capacity

The BAU 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 29.

Figure 49: Fuel Consumed by Type in the Business-as-Usual Strategy

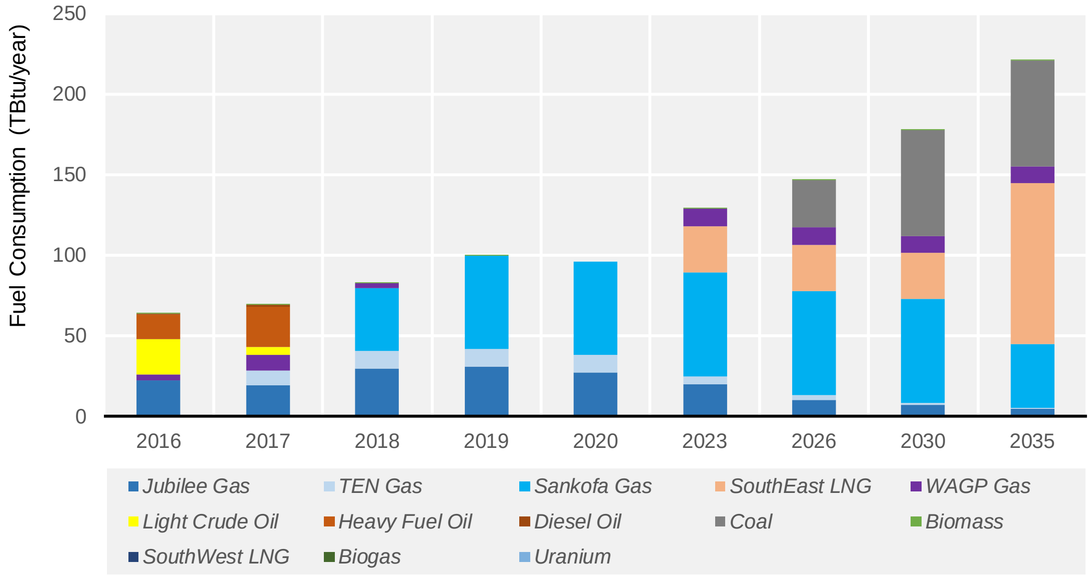


Figure 50: Comparison of Natural Gas Consumption for Reference Case Results of the Five Strategies

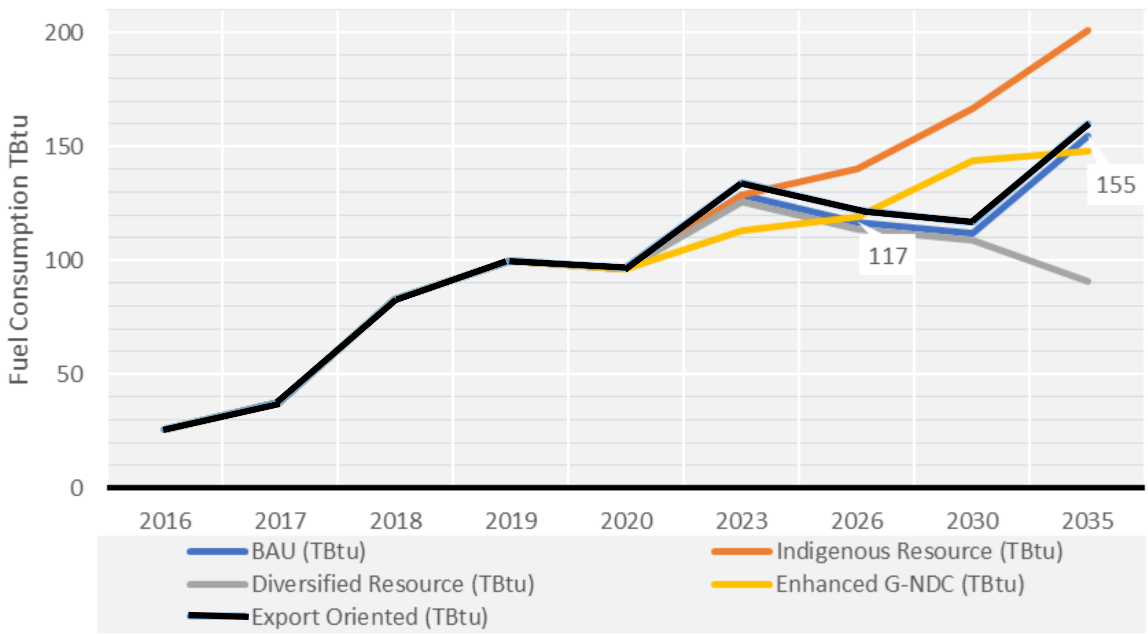


Table 29: Firm Transmission Upgrades Required for BAU

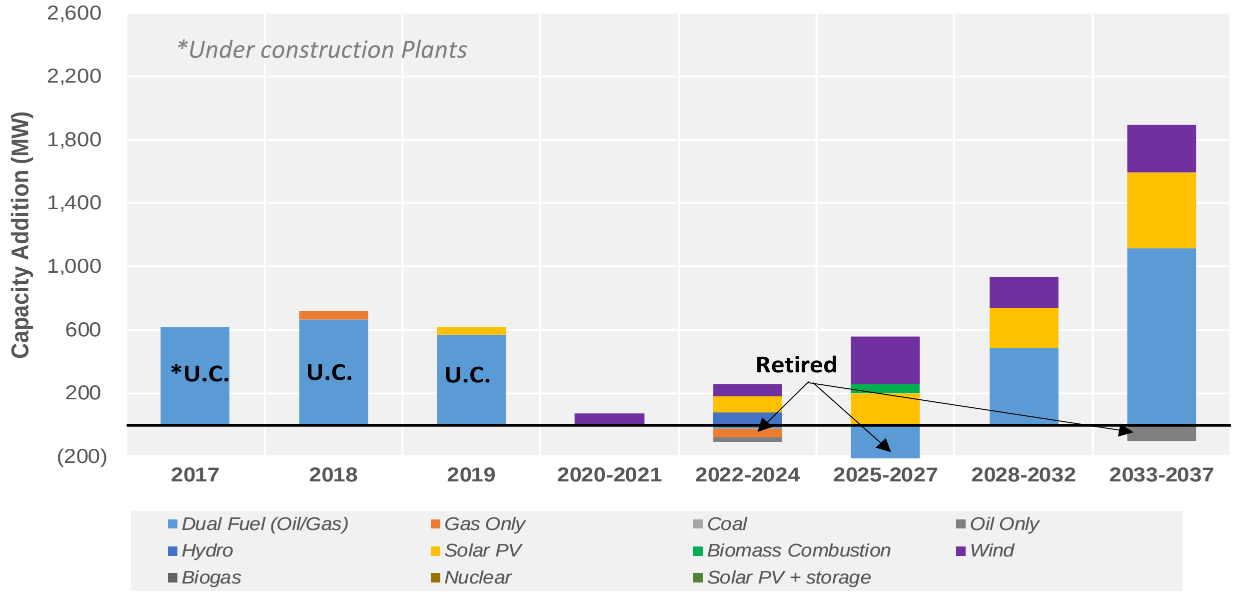
Origin Transmission Region Group	Destination Transmission Region Group	Firm Transmission Upgrade (MVA)	
		10-year	20-year
SouthEastGH	NorthGH Zone	220	330
SouthWestGH	AshantiGH Zone	-	240
SouthWestGH Zone	NorthGH Zone	-	360

7.2.2. Indigenous Resources Strategy

Generation Capacity

This strategy emphasises the use of Indigenous Resources, and as such the 10-year planning horizon sees more renewable units being built, relative to the BAU Strategy. As shown in Figure 51, in the medium term (2022–2027), two small hydropower plants (e.g., Pwalugu and Hemang) and a 60 MW biomass plant are built, which reduces the need for large conventional thermal plants. In the longer term, more solar PV and wind power are built from 2028 onward, with the need for increased investments in RE grid integration. Renewable energy penetration reaches about 9% by end of the 10-year period and about 13% by the end of the 20-year period. In the later years, however, more combined cycle plants are built.

Figure 51: Capacity Additions in the Indigenous Resources Strategy



In this strategy, the existing hydro and oil and gas units continue to contribute significantly to the total on-grid generation. By the year 2027, existing units would have contributed about 24 TWh yearly, higher than the 18 TWh of generation in 2020. New power plants will begin to steadily increase their contribution to generation and by the end of the 10-year period, they contribute about 2.6 TWh. Their contribution continues to increase to about 17 TWh by the end of the 20-year planning period, representing almost 47% of the total generation in that year. See Figure 52.

Generally, the capacity factors of existing oil and gas plants are relatively higher in the Indigenous Resource Strategy than the other strategies in the short-to-medium term as shown in Table 30. This is due to the fact that this strategy makes use of relatively higher volumes of natural gas. See Figure 50. Therefore, under this strategy, existing power plants are better utilised, which implies that this approach could be a low-cost option, as gas prices in Ghana moderate.

Figure 52: Annual Generation Profile in the Indigenous Resources Strategy

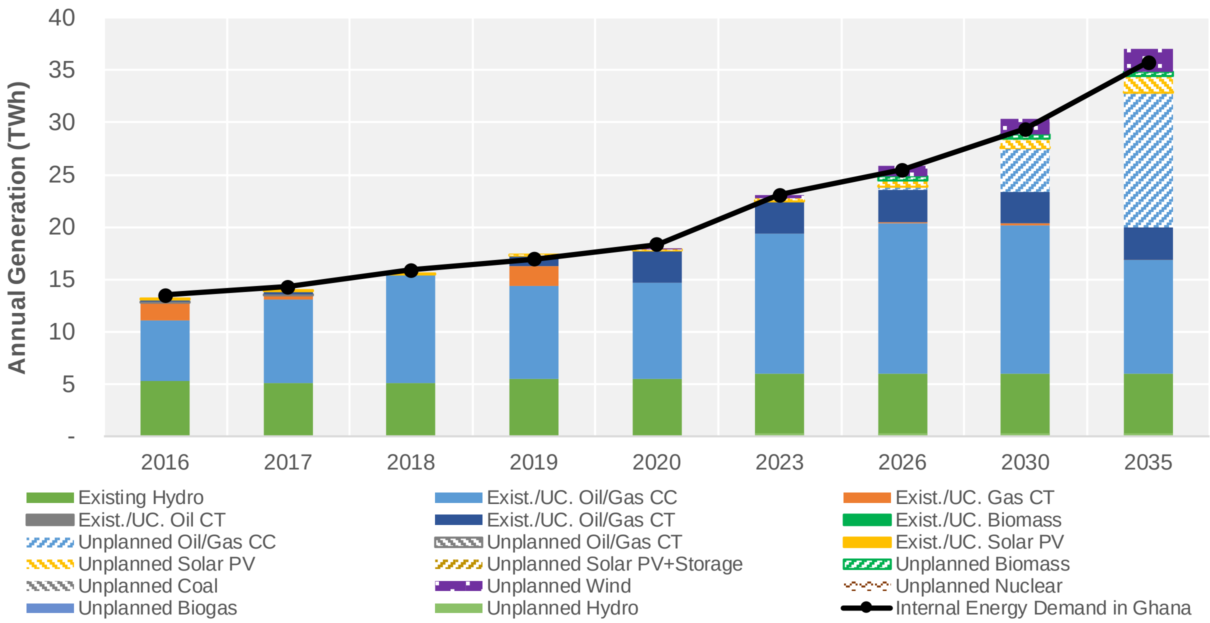


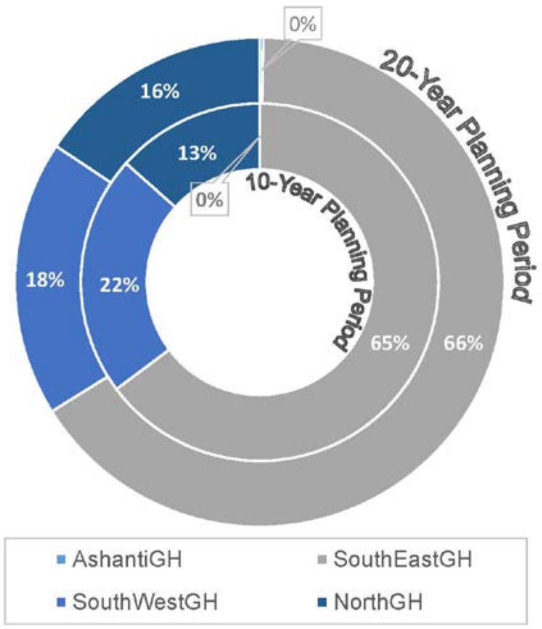
Table 30: Capacity Factors of Existing Natural Gas-Based Power Plants

	2017	2018	2019	2020	2023	2026	2030	2035
Business-as-Usual	39%	36%	35%	36%	50%	53%	50%	53%
Indigenous Resource	39%	36%	35%	36%	50%	61%	60%	50%
Diversified Resource	39%	36%	35%	36%	49%	51%	49%	42%
Enhanced G-NDC	39%	36%	35%	36%	39%	47%	57%	44%
Export-Oriented	39%	36%	36%	37%	52%	54%	52%	52%

Figure 53 shows that the SouthEastGH zone continues to have the highest share of installed generation capacity in this strategy. By the end of the 10-year period, the share of total installed capacity in the zone is about 65%, which increases in the longer term to 66%. This is due to more builds coming online in the later years, which are primarily combined cycle. In the SouthWestGH zone, a small hydro plant and some CCs are built in the late 2020s and to mid-2030s. The share in the SouthWest therefore decreases in the longer term. The NorthGH, however, sees an increase in the share of installed capacity from 13% in the 10-year period to 16% in the 20-year period. This is because this strategy builds large quantities of solar PV plants, which increases to about 900 MW at the end of the 20-year period.

There is no generation capacity in the Middlebelt zone by the end of the 10-year period because the only existing generating capacity in this zone, the Trojan 2A plant, retires in the early 2020s. This continues to be so until the mid-2030s when a 20 MW PV plant comes online. Nearly all of the electricity demand for the Middlebelt area is met through transmission from SouthEastGH and SouthWestGH zones.

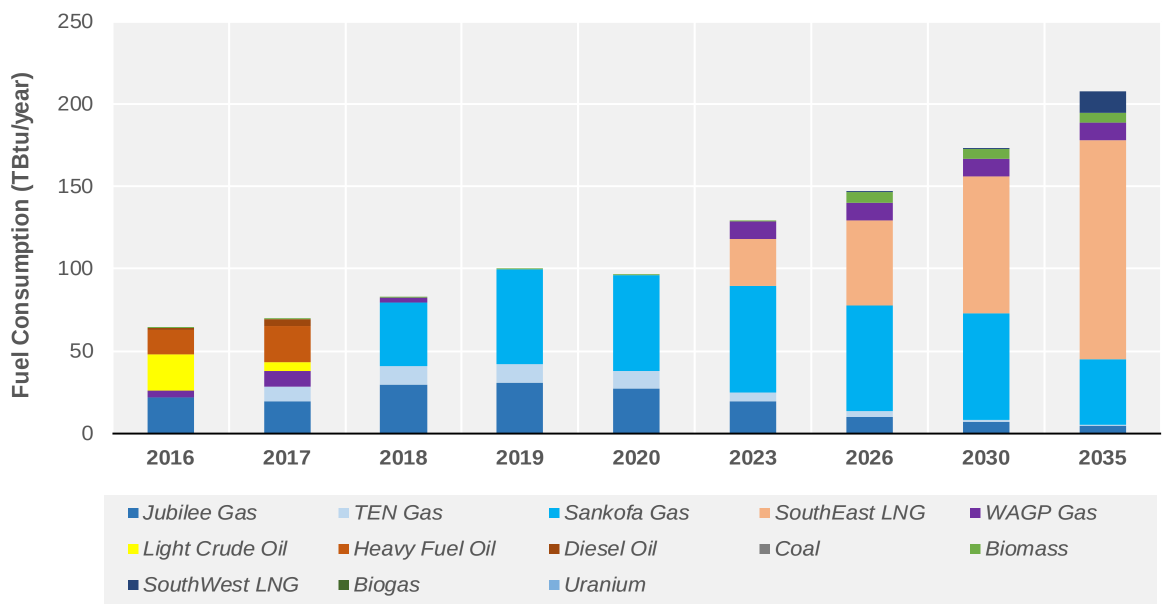
Figure 53: Distribution of Installed Capacity by Zones for the Indigenous Resources Strategy



Fuel Consumption

Due to the new combined cycle plants coming online in the mid-2020s in this strategy, more natural gas will be consumed in the Tema region. Although Figure 54 shows higher LNG consumption, it should be understood that LNG is simply a proxy for new gas needs for the power sector, and it can also come from WAGP and/or potential new fields yet to be discovered in Ghana.

Figure 54: Fuel Consumed by Type for the Indigenous Resources Strategy



The total annual volume of natural gas needed by 2027 is about 140 TBtu and this steadily increases to about 200 TBtu by 2037. This strategy makes the most use of natural gas resources, as shown in Figure 50. Similar to the BAU Strategy, it is made up of gas from the TEN, Sankofa, and the Jubilee fields up until 2023, when additional gas supply is needed from WAGP and other supplies (more WAGP, new domestic gas resources or LNG). There is no consumption of coal and uranium since this strategy focuses on development of indigenous energy resources and explicitly does not include coal and nuclear plants.

A small volume of biomass, about 7 TBtu per year, is consumed throughout the planning period, once the plant is built.

Transmission Capacity

The Indigenous Resources Strategy also requires more upgrades in the transmission network compared to the BAU Strategy. The upgrades are for only the SouthEastGH to NorthGH zones and the SouthWestGH to AshantiGH zones. The estimated transmission upgrades needed for both the 10-year and 20-year period are indicated in Table 31.

Table 31: Firm Transmission Upgrade Required for Indigenous Resources Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Firm Transmission Upgrade (MVA)	
		10-year	20-year
SouthEastGH	NorthGH	190	710
SouthWestGH	AshantiGH	-	210

7.2.3. Diversified Resources Strategy

Generation Capacity

This supply strategy emphasises fuel diversity by building:

- A 60 MW biomass plant in the early 2020s,
- A coal plant in the mid-2020s, similar to the BAU Strategy, and
- A 1000 MW nuclear power plant in early to mid-2030s.

Given all of this additional “forced” capacity, the amount of solar capacity installed is reduced by 80 MW in the 10-year period, relative to the BAU Strategy, with additional reduction of 170 MW in the next 10 years. This reduction is primarily due to the biomass plant that meets the RE generation target. There are no new combustion nor combined cycle gas-based power plants in this strategy over the next 20 years, as the nuclear and coal plants are sufficient to meet peak demand and energy demand. Figure 55 shows the capacity additions for this strategy. See also Table 26.

Existing hydro and thermal (oil and gas) units also significantly contribute to the total on grid generation in the country in this strategy. By the 2027, existing units contribute about 26 TWh to the total annual generation. New units begin to steadily increase their share by the end of the 10-year period with an annual contribution of about 5.5 TWh. This increase to about 20 TWh by the end of the 20-year planning period, representing about 52% of the total generation in that year. Refer to Figure 56.

Figure 55: Capacity Additions for the Diversified Resources Strategy

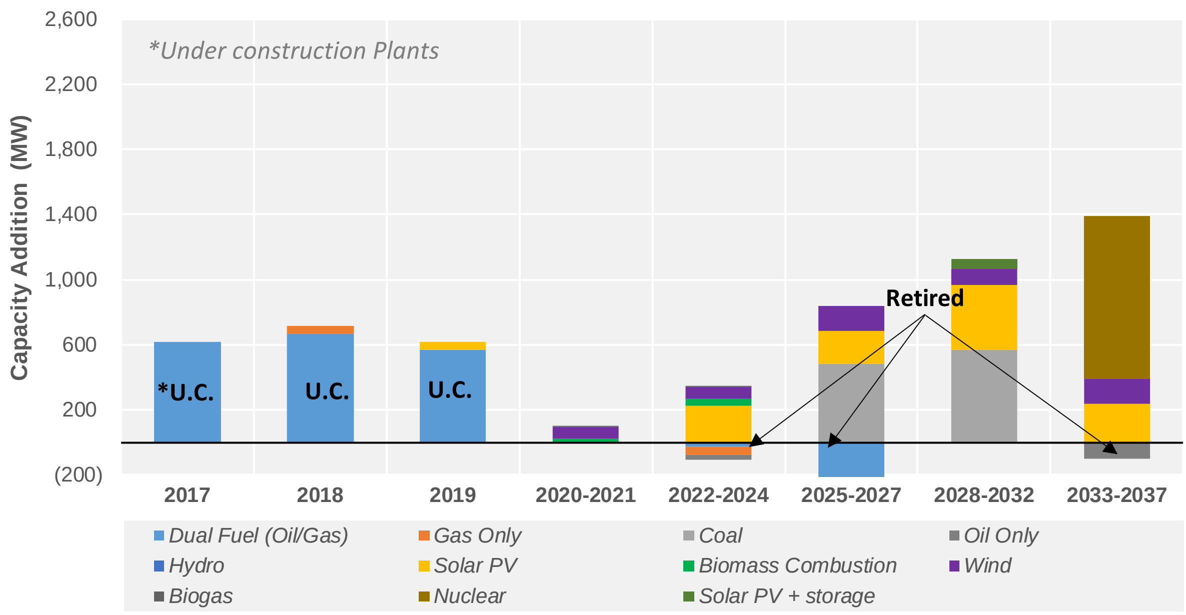
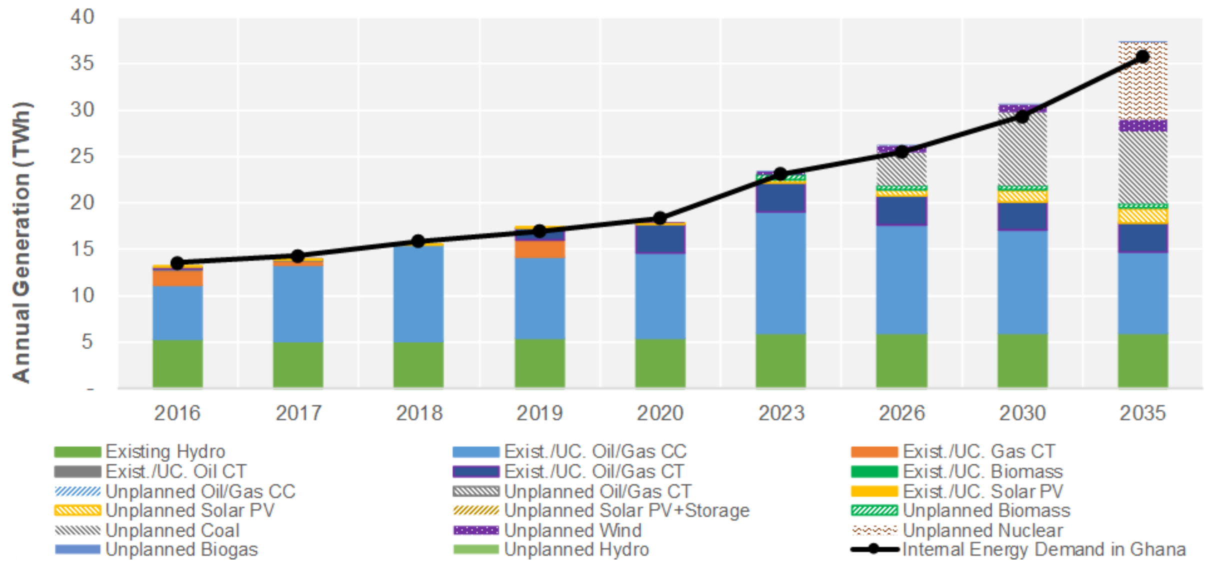


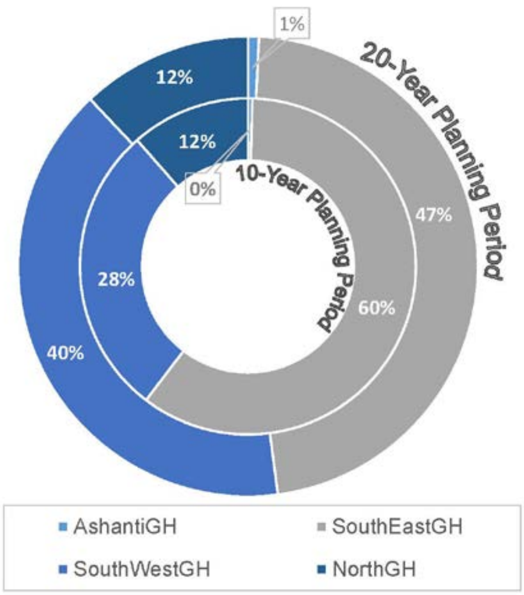
Figure 56: Annual Generation Profile for Diversified Resources Strategy



Similar to the BAU and the Indigenous Resources Strategy, the SouthEastGH zone has the highest share of installed generation capacity, as shown in Figure 57. By the end of the 10-year period, the share of total installed capacity in the SouthEastGH zone is about 60%, and it decreases to 47% in the longer term due to the addition of relatively more capacities in the SouthWestGH zone—namely, the additional 570 MW of coal which comes online in the early 2030s, the 1000 MW of nuclear power plant, and 350 MW of solar PV in the early to mid-2030s. This increases the share of installed capacity in the SouthWestGH zone from 28% in the 10-year period to 40% in the longer term. The NEDCO area maintains its share since relatively less capacity is added in the longer term.

The Middlebelt also has less than 1% of the share of installed capacity both in the 10-year and 20-year period. By the end of the 10-year period, it has only 30 MW of solar PV. The only existing generating capacity in this zone, the Trojan 2A plant, retires in the early 2020s. However, by the end of the 20-year period, the capacity in the Middlebelt increases to 60 MW, which comprises about 50 MW of solar PV and 10 MW of solar PV with storage. Of this capacity, only about 3 MW contributes to the reserve margin.

Figure 57: Distribution of Installed Capacity by Zones for the Diversified Resources Strategy



Fuel Consumption

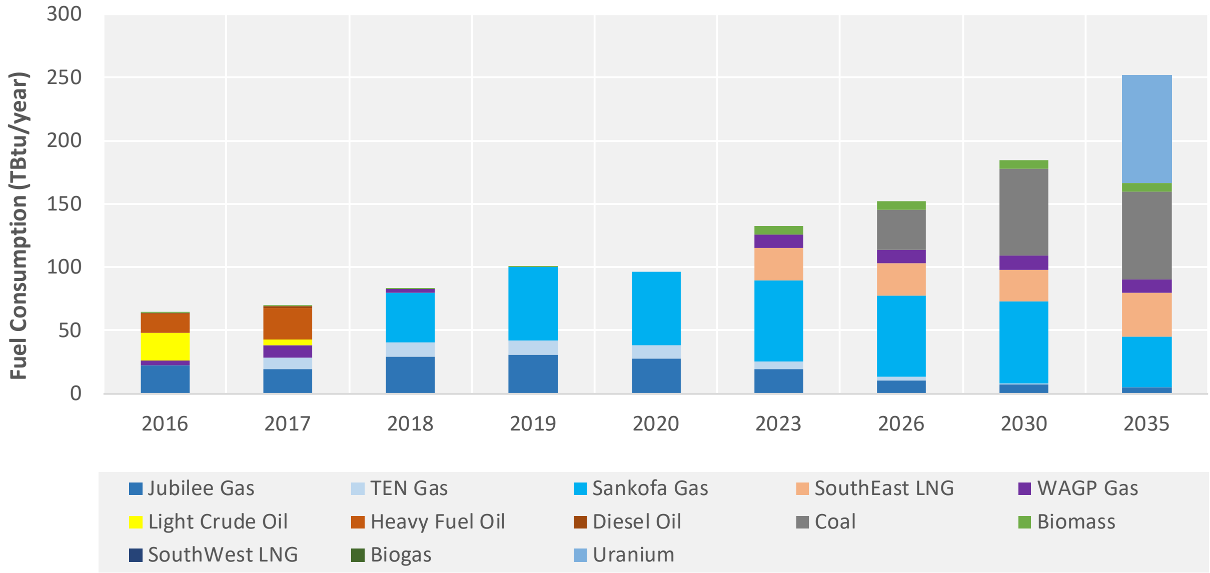
The total annual volume of natural gas needed in this strategy by 2027 is about 114 TBtu. This sees a steady decline in the ensuing years due to consumption of coal and nuclear fuel from the coal and nuclear plants that comes online. By the end of 2037, the volume of natural gas reduces to about 91 TBtu. Consumption of additional gas begins in the early 2020s with an annual average volume of about 25 TBtu from the Tema region.

Consumption of coal commences in the mid-2020s with an approximately 1055 MW coal plant coming online in the 2026. This sees a rise in the yearly coal consumption from about 750 Mt (32 TBtu) in 2027 to about 1,640 Mt (70 TBtu) by 2037.

When nuclear power comes online in the mid-2030s, about 85 TBtu per year of Uranium is required for power generation.

Consumption of gas from Nigerian gas from WAGP will be about 11 TBtu per year. Refer to Figure 58 for a detailed breakdown of the fuel type consumed by year.

Figure 58: Fuel Consumed by Type for the Diversified Resources 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 both the 10-year and 20-year period are indicated in Table 32.

Table 32: Transmission Upgrades Required for Diversified Resources Strategy

		Firm Transmission Upgrades (MVA)	
Origin Transmission Region Group	**Destination Transmission Region Group**	**10-year**	**20-year**
SouthWestGH	AshantiGH	25	440
SouthWestGH	NorthGH	190	760
SouthWestGH	SouthEastGH	-	120

7.2.4. Enhanced G-NDC Strategy

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 260 MW combined cycle plant to come online in the early 2020s, which was not needed in the BAU strategy.

Compared to the BAU strategy, a small thermal plant (i.e.115 MW of coal plant) is built in the mid-2020s for this strategy, which is significantly less than the 450 MW provided by coal plant built in the same period for the BAU. The small (unrealistic) amount of coal plant could be replaced by a gas-based plant, but coal plant is now being selected due to the increasing price of natural gas used in the analysis (see Figure 40 in Section 6.7.3). Also, if more stringent emissions constraint were to be enforced in the mid-2020s, the coal plant would not be selected to be built.

Additionally, a 460 MW nuclear plant is built in the mid-2030s, because of the avoidance of GHG emissions of nuclear plants, which supports the Enhanced G-NDC strategy. A 95 MW of biomass plant is also built by 2022, and relative to BAU, an additional 150 MW of wind and 720 MW of solar PV (which are emissions free generations) are added within the 10-year IPSMP horizon; 190 MW (out of the 720 MW of solar PV) is combined with battery storage. From 2028 to 2037, relative to the BAU, an additional 250 MW of wind and over 685 MW of solar capacity is added.

Existing hydro and oil and gas units significantly contribute to the total on grid generation in this strategy. By the 2027, the existing units contribute about 20 TWh, representing about 75% of total generation. New units begin to steadily increase share of generation and by the end of the 10-year period, they contribute about 7 TWh per year. This increases to 19 TWh per year by the end of the 20-year planning period, constituting about 51% of the total generation.

This strategy has the lowest total CO_2 emissions and CO_2 intensity as shown in Figure 61 and Figure 62. This is due to the presence of nuclear plants and the relatively higher mix of renewables in the generation mix.

Figure 59: Capacity Additions for the Enhanced G-NDC Strategy

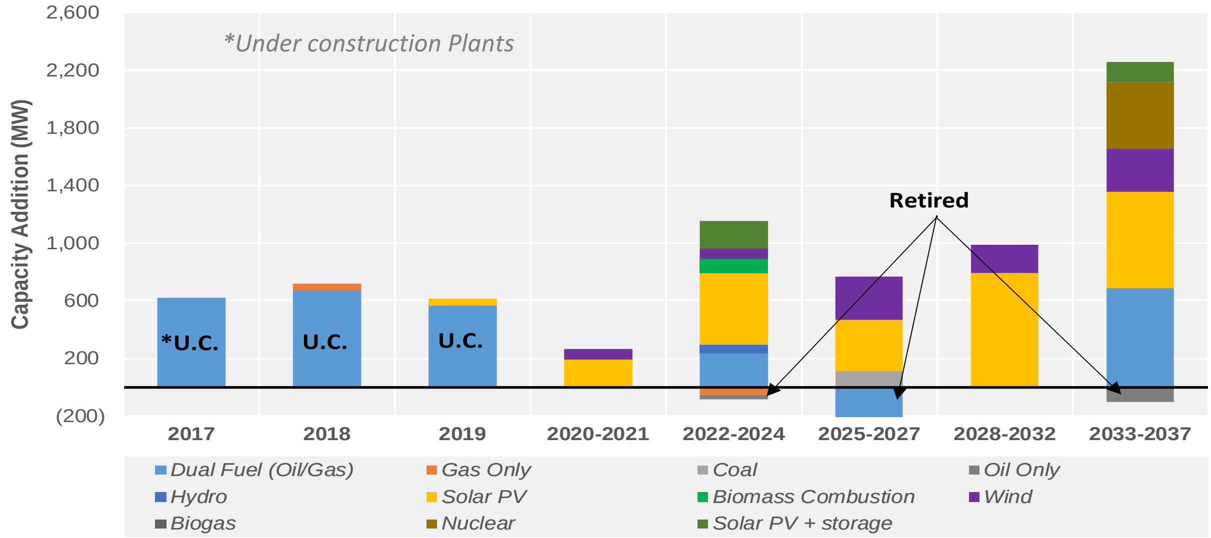


Figure 60: Annual Generation Profile for the Enhanced G-NDC Strategy

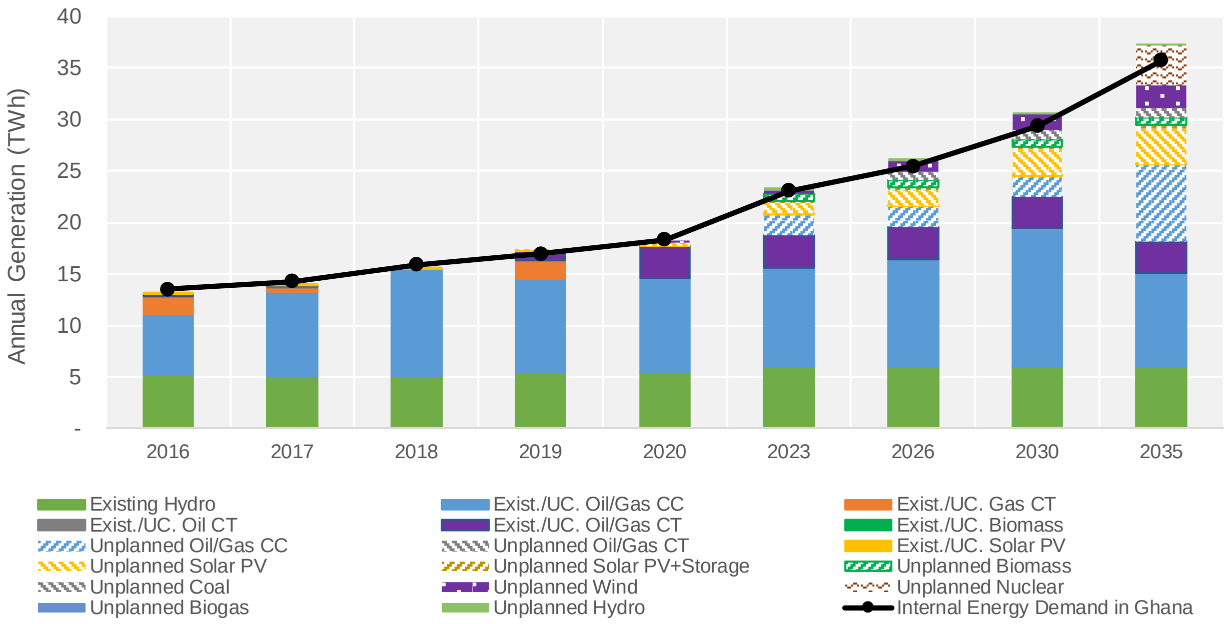


Figure 61: Total CO_2 Emission for the Strategies

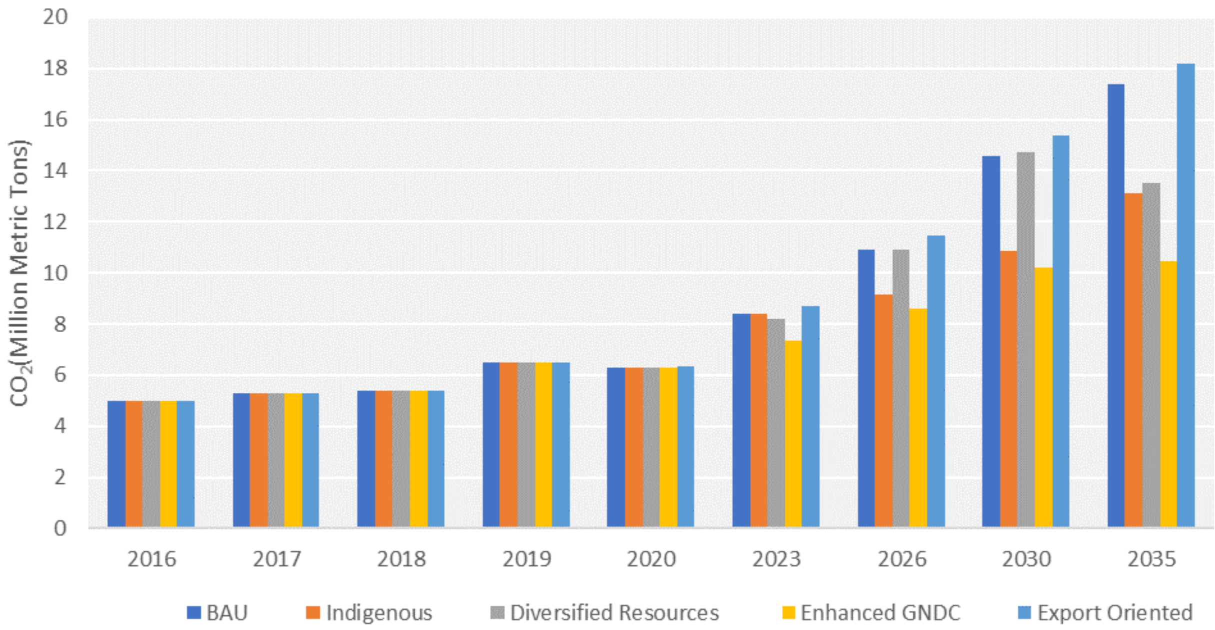
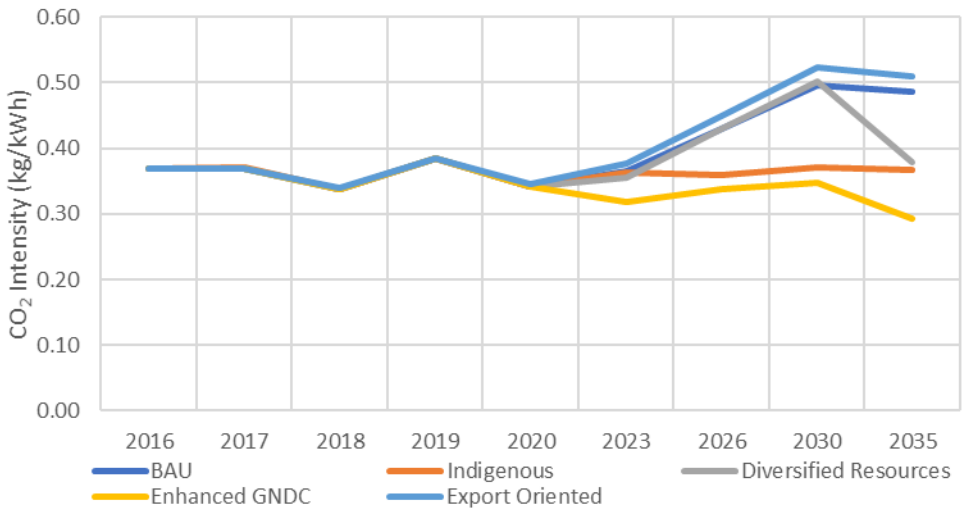


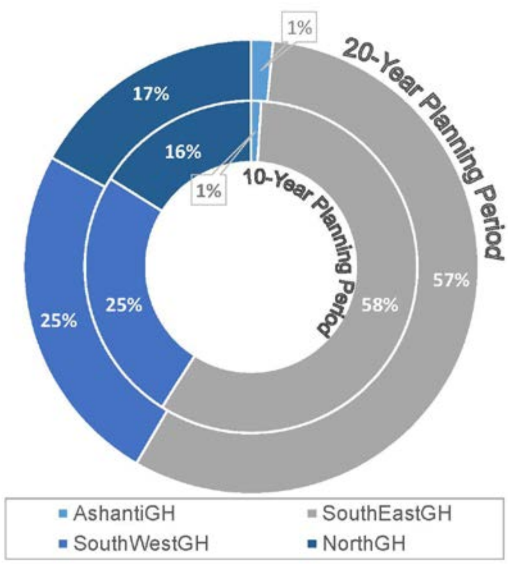
Figure 62: Comparison of CO_2 Intensity for Strategies



The SouthEastGH zone continues to have the highest share of installed generation capacity in this strategy for both the 10-year and 20-year period as shown in Figure 63. By the end of the 10-year period, the share of total installed capacity in the SouthEastGH zone is about 58%, and it essentially remains the same by the end of the 20-year period.

The Middlebelt moves from having more than 70 MW of total capacity (biomass, solar PV, and solar PV with storage) by the end of the 10-year period to about 160 MW by the 20-year period. With this increase, the amount of capacity in Middlebelt remains at about 1% of total capacity in Ghana. The share of the installed capacity for the SouthWestGH zone also remains the same throughout the 10-year and 20-year periods, with about 300 MW of combined cycle and the small hydro unit coming online.

Figure 63: Distribution of Installed Capacity by Zones for the Enhanced G-NDC Strategy



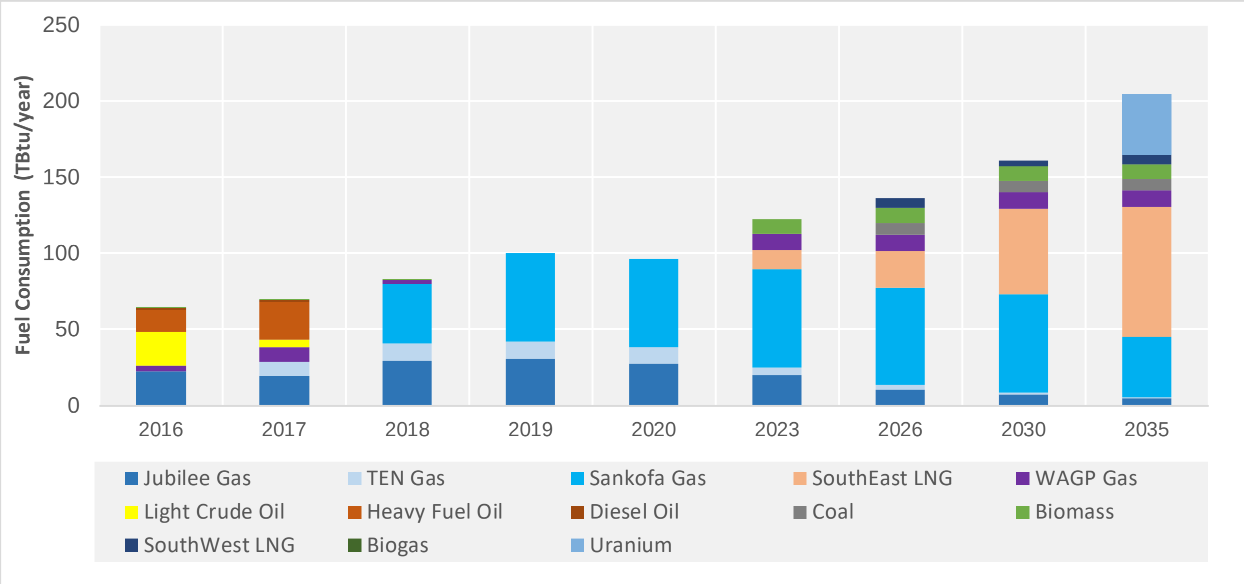
Fuel Consumption

The total annual volume of natural gas needed in this strategy by 2027 is about 120 TBtu which increases to about 150 TBtu by 2037. The natural gas consumed is primarily gas from the TEN, Sankofa, and the Jubilee fields up until 2023, when additional gas volumes are needed to meet demand, starting off with an annual volume of about 13 TBtu that increases to about 92TBtu.

About 40 TBtu per year of uranium is consumed annually when the nuclear plant comes online in the mid-2030s.

Figure 64 details the fuel consumption by type and by source for natural gas in the Enhanced G-NDC strategy.

Figure 64: Fuel Consumed by Type for the Enhanced G-NDC Strategy



Transmission Capacity

This strategy also requires upgrades in the transmission network from the SouthEast to NEDCo area and the SouthWestGH to Middlebelt and NEDCo areas. The details for the estimated total transmission upgrades for the 10-year the 20-year period are indicated in Table 33.

Table 33: Transmission Upgrades Required for Enhanced G-NDC Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Firm Transmission Upgrade (MVA)	
		10-year	**20-year**
SouthEastGH	NorthGH	170	460
SouthWestGH	AshantiGH	-	270
SouthWestGH	NorthGH	-	150

7.2.5. Export-Oriented Strategy

Generation Capacity

This strategy is the same as the BAU, with the exception of increased demand for exports. Therefore, the build portfolio is very similar to the BAU, with an additional 155 MW of combined cycle and a slight increase in coal capacity by about 65 MW relative to the BAU. Figure 65 shows the new capacity additions for the Export-Oriented Strategy and Figure 66 shows the generated electricity in this strategy.

Figure 65: Capacity Additions for the Exported-Oriented Strategy

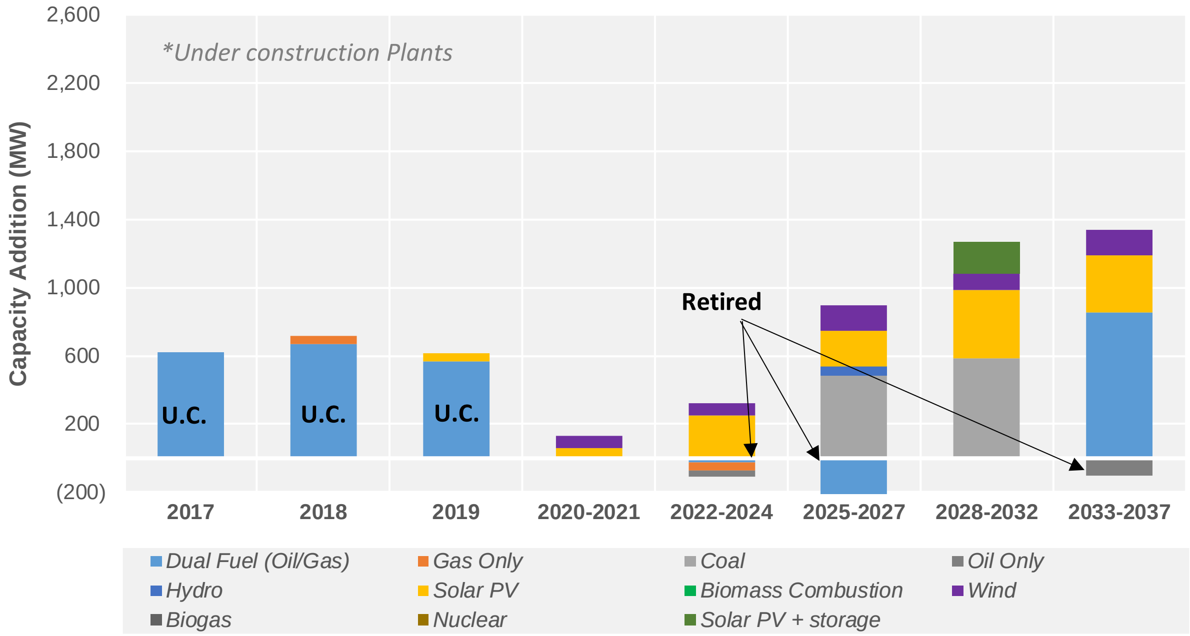
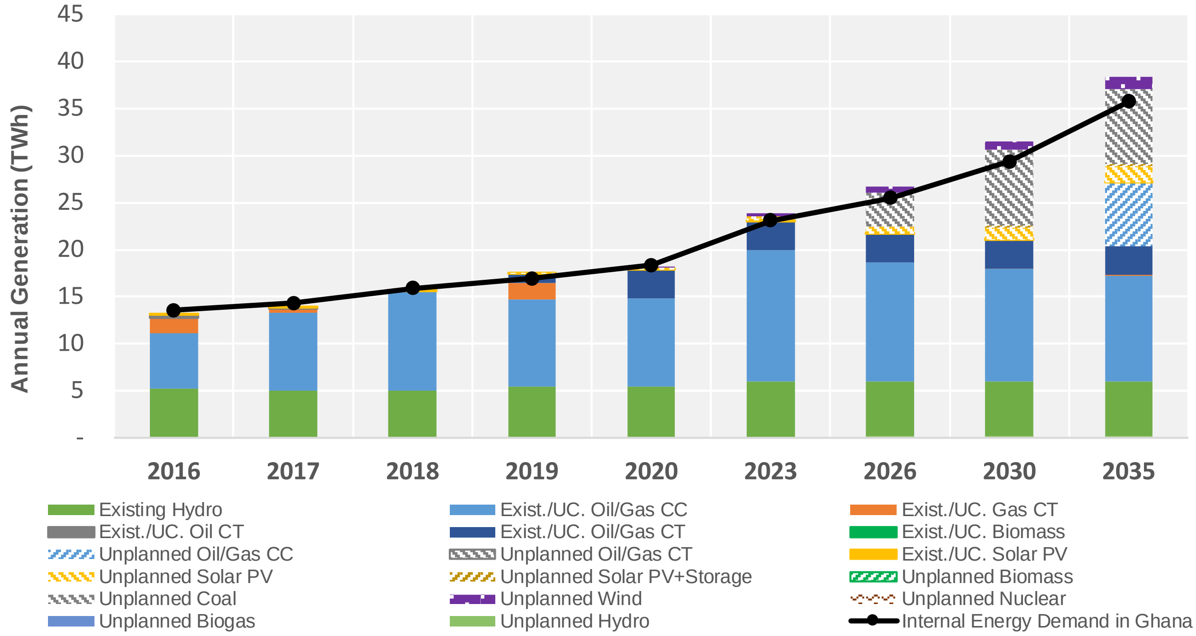


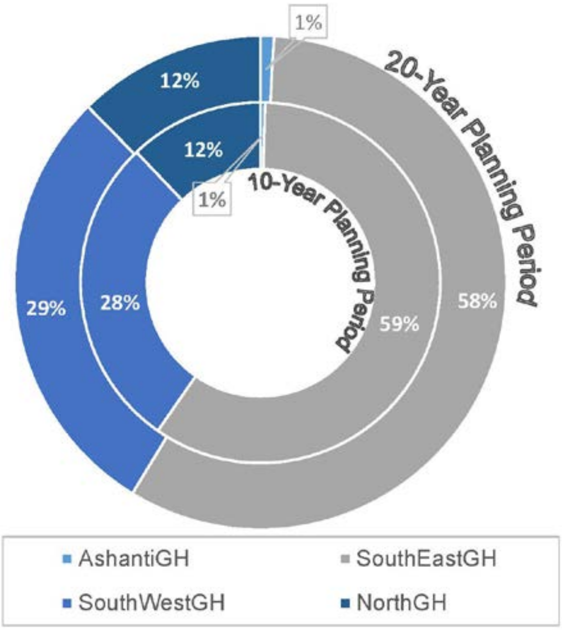
Figure 66: Annual Generation Profile for the Export-Oriented Strategy



The share of installed capacities across the zones is similar to that of the BAU. However, this strategy has a slightly lower share of installed capacity in the SouthEastGH zone of about 59% by the 10-year period, which reduces to 58% in the longer term due to the addition of more plants in the SouthWestGH zone—primarily, an additional 590 MW of coal power plant in addition to the 480 MW that come online in the mid-2020s.

The NorthGH builds more than 700 MW of solar PV and about 60 MW of small hydro units by the end of the 10-year period. It adds an additional 300 MW of solar PV plants with some storage options in the longer term, however its overall share does not change much in the longer term.

Figure 67: Distribution of Installed Capacity by Zones for the Export-Oriented Strategy

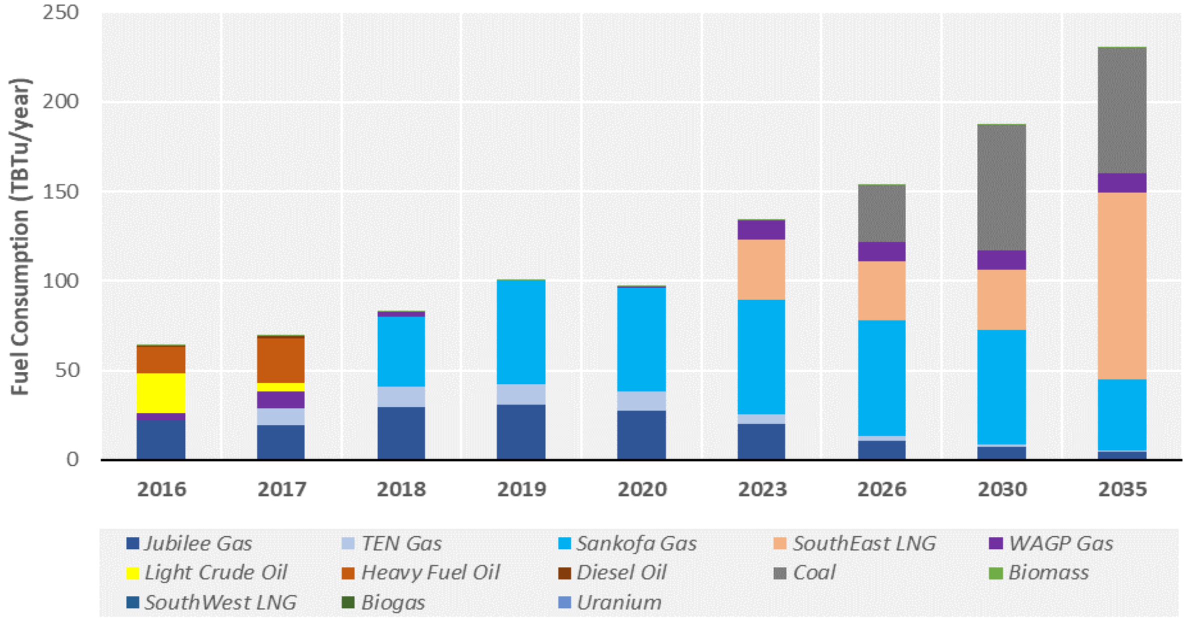


Fuel Consumption

As shown in Figure 68, the fuel consumption pattern is very similar to the BAU; domestic gas is consumed primarily in this strategy until early 2020s when more gas is needed than is in the Reference Case production volumes. Relatively more gas is consumed in this strategy than the BAU, and by 2027 about 120 TBtu per year is consumed. This consumed volume, similar to the BAU, declines subsequently due to the coming online of the coal plant and goes back up in the early 2030s as demand increases and other new gas units comes online. By the end of the 20-year planning period (2037) the consumption increases to about 160 TBtu. Refer to Figure 50.

Similar to the BAU, consumption of coal commences due to the 1070 MW coal plant in mid-2020s. It commences with about 750 Mt per year (32 TBtu) in 2026 and increases to about 1600 Mt per year (70 TBtu) by the end of the 20-year planning period.

Figure 68: Fuel Consumed by Type for the Export-Oriented Strategy



Transmission Capacity

This strategy requires a significant upgrade in transmission network for only the SouthEastGH to NorthGH zone, and the SouthWestGH to the Middlebelt.

The estimated transmission upgrades for the various transmission paths are indicated in Table 34.

Table 34: Transmission Upgrades Required for the Export-Oriented Strategy

Origin Transmission Region Group	Destination Transmission Region Group	Firm Transmission Upgrade (MVA)	
		10-year	20-year
SouthEastGH	NorthGH	300	410
SouthWestGH	AshantiGH	-	240
SouthWestGH	NorthGH	-	430

7.3. 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 23 of Section 7.2) were fixed for the entire planning period, and these results were then “tested” over the full range of sensitivities (see Table 24). So, for each strategy, there were 14 run results including the reference assumptions, and a total of 70 run results for the entire strategy-sensitivity combinations. The metrics for each of the sensitivities for the BAU and Indigenous Resources strategies are shown in Table 35 and Table 36, respectively. Similar tables for all the other strategies are in the Appendix of this report.

Cost Metric

Results for the cost metrics 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 show the cumulative overnight investment costs for each strategy, across all of the sensitivities, over the 10-year and 20-year periods, respectively. For each strategy, the average of all the sensitivities is also shown (as red diamonds 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 37 for a summary of all the strategies for both 10- and 20-year periods.

The Enhance G-NDC portfolio seems to be the worst performing strategy under the cost metric, given the relatively high cost and wide variation of the investment cost under the various sensitivities. However, in the 20-year planning period, the Diversified Resource portfolio becomes more expensive with a total investment of about $3.9 billion (in real 2016$). The Indigenous Resources Strategy, on the other hand, represents the strategy with the lowest cumulative investment cost with about $952 million and $2.4 billion for the 10-year and 20-year planning horizon, respectively.

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 system cost can increase by as much as 20% to 60% depending on specific sensitivity. However, on average, the lowest cumulative total system cost is recorded by the Indigenous Resources Strategy with an average system cost of about $7.77 billion, which was about $11 million USD lower than the BAU over the 10-year period. The total system cost for the BAU portfolio is slightly cheaper in the longer term due decreased consumption of high-price natural gas. However, if there is sufficient low-priced indigenous natural gas or if imported LNG is priced at long-term contract prices, then total system cost of the Indigenous Resources Strategy continues to be better than BAU even in the longer term.

In general, the Indigenous Resources and the BAU strategies have relatively lower costs across both cost metrics.

Table 35: Metrics for 10 Years (2018–2027) for BAU Strategy

METRIC	Unit	RefCase	High Demand	Low Demand	High Fuel Cost	Low Fuel Cost	Limited Fuel Supply	High Fuel Supply	Limited Water Availability	Higher RE Capital Costs	Lower RE Capital Costs	High Demand, High Resource Cost, Low Fuel/Water Availability	Low Demand, High Resource Cost, Low Fuel/Water Availability	Lower RE Capital Costs and Higher Fuel Costs	Lower Capital Cost for Conventional Resources	AVERAGE
Total Investment / Capital Cost	M USD	1394	1394	1394	1394	1394	1394	1394	1394	1489	1216	1489	1489	1216	1326	**1384**
Total System Cost	M USD	7511	9617	6499	7862	5856	7902	8250	7578	7571	7441	12075	5471	7793	7490	**7780**
Unserved Energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Unserved Peak	MW	217	1629	213	217	217	217	217	217	217	217	1629	213	217	217	**418**
Transmission Congestion	%	21%	28%	20%	20%	22%	23%	21%	20%	21%	21%	28%	16%	20%	21%	**22%**
Resource Type Diversity [Dom vs. Imported]	% GWh	84%	71%	89%	84%	82%	76%	70%	83%	84%	84%	62%	91%	84%	84%	**80%**
Fast-Ramp/Variable RE Capacity	Ratio	18	18	18	18	18	18	18	18	18	18	18	18	18	18	**18**
Local Reserve	MW	354	354	354	354	354	354	354	354	354	354	354	354	354	354	**354**
Air Quality (So_x, No_x)	Thousand Tonnes	59	77	53	59	59	57	71	59	59	59	68	36	59	59	**59**
GHG	Thousand Tonnes	8247	10545	6570	8247	8257	8865	8907	8330	8247	8247	12116	5371	8247	8247	**8460**
Ash Production	Thousand Tonnes	73	73	0	73	73	73	0	73	73	73	73	73	73	73	**63**
Land Requirements	Acres	113736	113736	113736	113736	113736	113736	113736	113736	113736	113736	113736	113736	113736	113736	**113736**

Table 36: Metrics for 10 Years (2018–2027) for Indigenous Resources Strategy

METRIC	Unit	RefCase	High Demand	Low Demand	High Fuel Cost	Low Fuel Cost	Limited Fuel Supply	High Fuel Supply	Limited Water Availability	Higher RE Capital Costs	Lower RE Capital Costs	High Demand, High Resource Cost, Low Fuel/Water Availability	Low Demand, High Resource Cost, Low Fuel/Water Availability	Lower RE Capital Costs and Higher Fuel Costs	Lower Capital Cost for Conventional Resources	AVERAGE
Total Investment / Capital Cost	M USD	967	967	967	967	967	967	967	967	1077	700	1077	1077	700	960	**7.72**
Total System Cost	M USD	7606	9790	5621	8063	5789	8019	7517	7683	7682	7508	12502	5413	7965	7604	**952**
Unserved Energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Unserved Peak	MW	217	2205	213	217	217	217	217	217	217	217	2205	213	217	217	**501**
Transmission Congestion	%	23%	29%	17%	22%	22%	22%	23%	22%	23%	23%	27%	17%	22%	22%	**22%**
Resource Type Diversity [Dom vs. Imported]	% GWh	84%	72%	99%	84%	82%	76%	98%	84%	84%	84%	62%	94%	84%	84%	**84%**
Fast-Ramp/Variable RE Capacity	Ratio	20	20	20	20	20	20	20	20	20	20	20	20	20	20	**20**
Local Reserve	MW	367	367	367	367	367	367	367	367	367	367	367	367	367	367	**367**
Air Quality (So_x, No_x)	Thousand Tonnes	62	81	44	62	62	59	66	62	62	62	70	38	62	62	**61**
GHG	Thousand Tonnes	7716	10132	5545	7716	7805	8460	8216	7811	7716	7716	11883	4843	7716	7716	**7928**
Ash Production	Thousand Tonnes	2.91	2.91	0.01	2.91	0.01	2.91	2.91	3	3	3	3	2	3	3	**2**
Land Requirements	Acres	156084	156084	156084	156084	156084	156084	156084	156084	156084	156084	156084	156084	156084	156084	**156,084**

Table 37: Average across Sensitivities for 10- and 20-Year Planning Horizon

10-Year	COST METRICS		RELIABILITY METRIC			RESILIENCE METRIC			LOCAL ENVIRONMENT METRIC		LAND USE	CLIMATE METRIC
	Total Investment Cost	Total System Cost	Unserved Energy	Transmission Congestion	Unserved Peak	Local Reserve	Fast-Ramp/Variable RE Capacity	Resource Type Diversity [Dom vs. Imported]	Air Quality (SO_x, NO_x)	Ash Production	Land Requirements	CO_2
	M USD	*M USD*	*GWh*	*%*	*MW*	*MW*	*Ratio*	*% GWh*	*Thousand Tonnes*	*Thousand Tonnes*	*Acres*	*Thousand Tonnes*
Business-as-Usual	1,384	7,780	0	22%	418	354	18.3	80%	59	63	113,736	8460.4
Indigenous Resources	952	7,769	0	22%	501	367	20.3	84%	61	2	156,084	7928.0
Diversified Resource	1,425	7,869	0	21%	413	377	19.5	83%	58	72	2,545	8401.0
Enhanced G-NDC	1,969	7,849	405	25%	407	398	16.3	88%	50	19	115,685	6974.2
Export-Oriented	1,435	7,814	0	22%	348	354	18.3	81%	61	66	113,756	8690.4
20-Year												
Business-as-Usual	3,101	13,341	0	25%	418	380	9.8	65%	60	274	118,031	11649.0
Indigenous Resources	2,398	13,475	0	23%	501	389	10.8	69%	63	6	160,051	9645.2
Diversified Resource	3,927	13,511	0	25%	413	392	10.4	67%	56	295	6,087	10958.7
Enhanced G-NDC	3,844	13,652	203	32%	407	419	8.5	73%	52	44	121,905	8404.1
Export-Oriented	3,225	13,451	0	25%	348	380	9.8	66%	61	291	118,121	12076.3

Figure 69: Performance of Strategies under the Various Sensitivities for the Total Investment Cost Metric for 10-Year Planning Horizon

Figure 70: Performance of Strategies under the Various Sensitivities for the Total Investment Cost Metric for 20-Year Planning Horizon

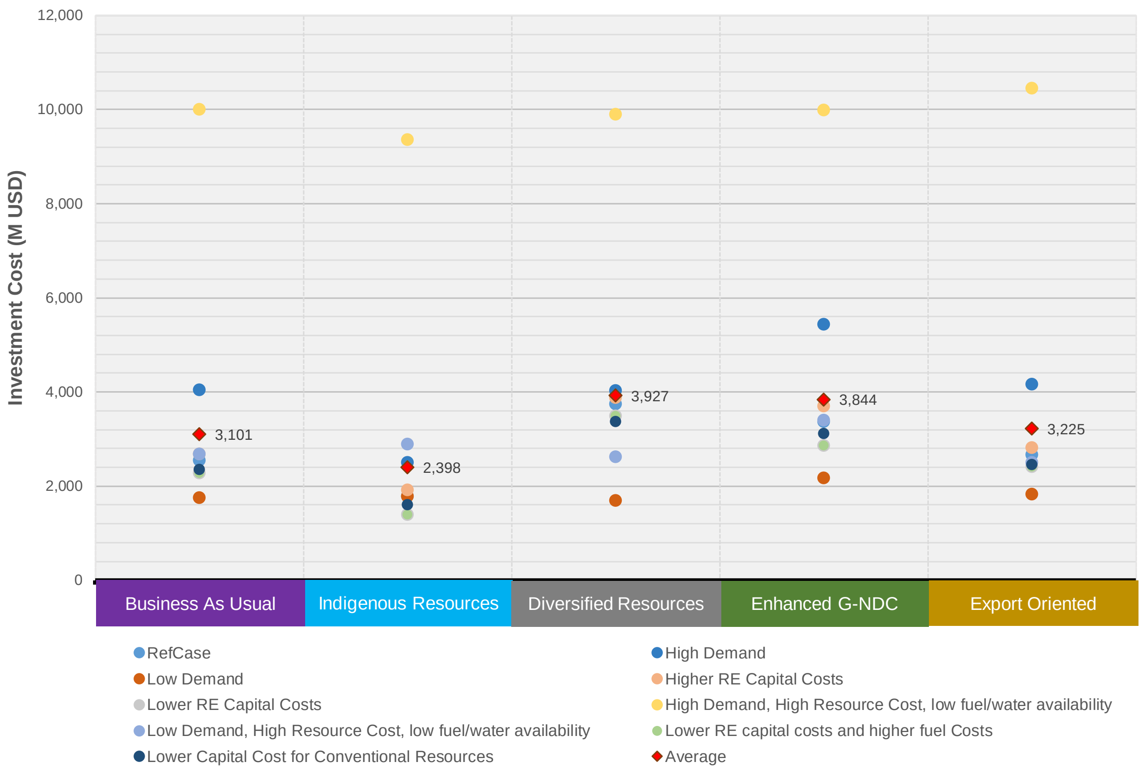


Figure 71: Performance of Strategies under the Various Sensitivities for the Total System Cost Metric for 10-Year Planning Horizon

Figure 72: Performance of Strategies under the Various Sensitivities for the Total System Cost Metric for 20-Year Planning Horizon

Other Metrics

An average (across all sensitivities), about 407 MW of unserved peak was realised across all the strategies in the Enhance G-NDC Strategy, making it the worst strategy under this metric. This was mainly because of the inability of the plants to fully serve the projected energy demand due to the constraints on CO_2 emissions in the high-demand scenarios. See Table 37.

However, for the other reliability metrics, such as the transmission congestion and the unserved peak, there were just very minor differences among the strategies—although the Diversified Resource and the Export-Oriented strategies are the best for these metrics over the 10-year period. In the 20-year period, however, the Indigenous Resources and the Export-Oriented strategies have the lowest transmission congestion and the lowest unserved peak demand, respectively.

For the broader theme of resilience, the metrics are local reserve capacity, fast-ramp capacity, and fraction of domestic resources for generation. The Enhance G-NDC performs very well under the local reserve metric since it is the strategy with the highest share of generation in the NEDCo and Middlebelt areas in both the 10-year and 20-year period; the Enhanced G-NDC Strategy records the highest ratio of about 88% followed by the Indigenous Resource Strategy. The fast-ramp capacity ratio indicates the share of fast-ramp capable power plants that can provide grid support for variable renewables. The Indigenous Resources Strategy has the highest ratio in both the 10-year and 20-year periods.

The best performing strategy under the air quality metric is the Enhanced G-NDC Strategy in both the 10-year and the 20-year period due to the greater renewable energy mix and nuclear in build portfolio.

Under the land use metric, the Diversified Resource Strategy performs the best due to the fact that it builds more conventional plants, such as nuclear and coal, with relatively lower footprints than hydropower and solar PV.

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.

7.4. 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). These strategies were then further evaluated against the other metrics to test their overall performance.

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 38, which shows the ranking for the various strategies across all the metrics for the 10- and 20-year period. 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 39.

Similar rating and rankings were conducted for each strategy for both the 10- and 20-year time periods using the average of the respective metrics across all the sensitivities—see Table 38 to Table 41.

The analysis shows that the Indigenous Resources performs relatively well under all the other metrics, with the exception of the land use metric. On this land use metric, the Indigenous Resources Strategy scores the worst because of the 600+ square kilometres of land required to build the two hydropower units. However, the IRRP Steering and Technical Committees were comfortable with the decision to build hydropower plants, as indicated in this strategy.

Therefore, the Indigenous Resources Strategy was deemed the most favorably ranked strategy in terms of cost and performance of all other metrics, relative to the other strategies, and there qualifies as the *Least-Regrets* Strategy for the IPSMP. The Indigenous Resources Strategy is largely characterised by development of renewables and combined cycle plants, with some appreciable level of transmission upgrades. The specific build portfolio for the 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.
- Coal and nuclear plants are not considered in this strategy because their fuels are not indigenous.
- Overall investment cost required is low, due to the assumed declining cost of solar and wind, and the fact that this strategy best uses the existing natural gas plants.
- Natural gas is the primary conventional fuel used in this strategy, and if the cost of natural gas is down, the total system cost of this strategy will drop considerably lower than shown in the current analysis.
- 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.
- In the long run, when new conventional plants come online, the capacity factor of existing plants will go down. If for contractual reasons, existing plants need to be run with higher capacity factors, the system cost will increase, which might have implications on tariffs.
- As new capacities are added in the NEDCo area, transmission losses will go down.
- In this strategy there is still relatively low generation capacity in the Middlebelt, 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 38: Ranking of the Strategies for 10-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC			RESILIENCE METRIC			LOCAL ENVIRONMENT METRIC		LAND USE	CLIMATE METRIC
	Total Investment Cost	Total System Cost	Unserved energy	Transmission Congestion	Unserved Peak	Local Reserve	Fast Ramp/Variable RE Capacity	Resource type diversity [Dom vs. Imported]	Air Quality (Sox, Nox)	Ash Production	Land requirements	CO_2
Business-As-Usual	4.3	1.1	0.0	2.1	4.6	10.0	4.9	10.0	8.7	8.6	7.2	8.7
Indigenous Resource	0.0	0.0	0.0	3.6	10.0	7.1	0.0	5.4	10.0	0.0	10.0	5.6
Diversified Resource	4.6	10.0	0.0	0.0	4.2	4.9	2.0	7.1	7.9	10.0	0.0	8.3
Enhanced G-NDC	10.0	8.0	10.0	10.0	3.9	0.0	10.0	0.0	0.0	2.4	7.4	0.0
Export Oriented	4.7	4.5	0.0	2.4	0.0	10.0	4.9	9.5	9.9	9.0	7.2	10.0

Table 39: Combined Ranking of the Strategies across the Various Metrics for the 10-Year Planning Period

	Cost Metric	Reliability Metric	Resilience Metric	Local Environment Metric	Land Use Metric	Climate Metric
Indigenous Resources – Strategy II	0.0	5.2	1.7	4.6	10.0	5.6
Business as Usual – Strategy I	3.0	2.0	10.0	9.0	7.2	8.7
Export Oriented – Strategy V	5.1	0.0	9.7	10.0	7.2	10.0
Diversified Resources – Strategy III	8.1	0.9	2.7	9.4	0.0	8.3
Enhanced G-NDC – Strategy IV	10.0	10.0	0.0	0.0	7.4	0.0

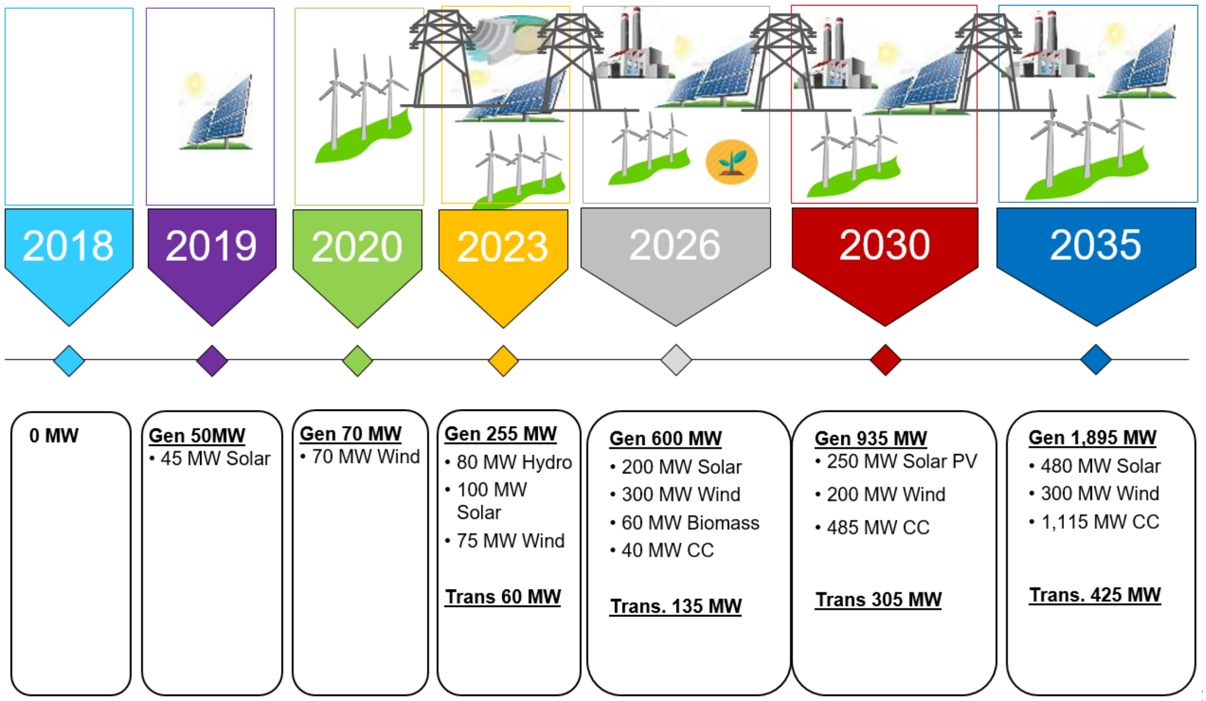
Table 40: Ranking of the Strategies for 20-Year Planning Horizon

	COST METRICS		RELIABILITY METRIC			RESILIENCE METRIC			LOCAL ENVIRONMENT		LAND USE	CLIMATE METRIC
	Total Investment Cost	Total System Cost	Unserved energy	Transmission Congestion	Unserved Peak	Local Reserve	Fast Ramp/Variable RE Capacity	Resource type diversity [Dom vs. Imported]	Air Quality (Sox, Nox)	Ash Production	Land requirements	CO_2
Business-As-Usual	4.6	0.0	0.0	2.2	4.6	10.0	4.5	10.0	7.5	9.3	7.3	8.8
Indigenous Resource	0.0	4.3	0.0	0.0	10.0	7.8	0.0	5.1	10.0	0.0	10.0	3.4
Diversified Resource	10.0	5.5	0.0	1.8	4.2	7.0	1.6	7.9	3.5	10.0	0.0	7.0
Enhanced G-NDC	9.5	10.0	10.0	10.0	3.9	0.0	10.0	0.0	0.0	1.3	7.5	0.0
Export Oriented	5.4	3.5	0.0	2.3	0.0	10.0	4.5	9.4	8.4	9.8	7.3	10.0

Table 41: Combined Ranking of the Strategies across the Various Metrics for the 20-year Planning Period

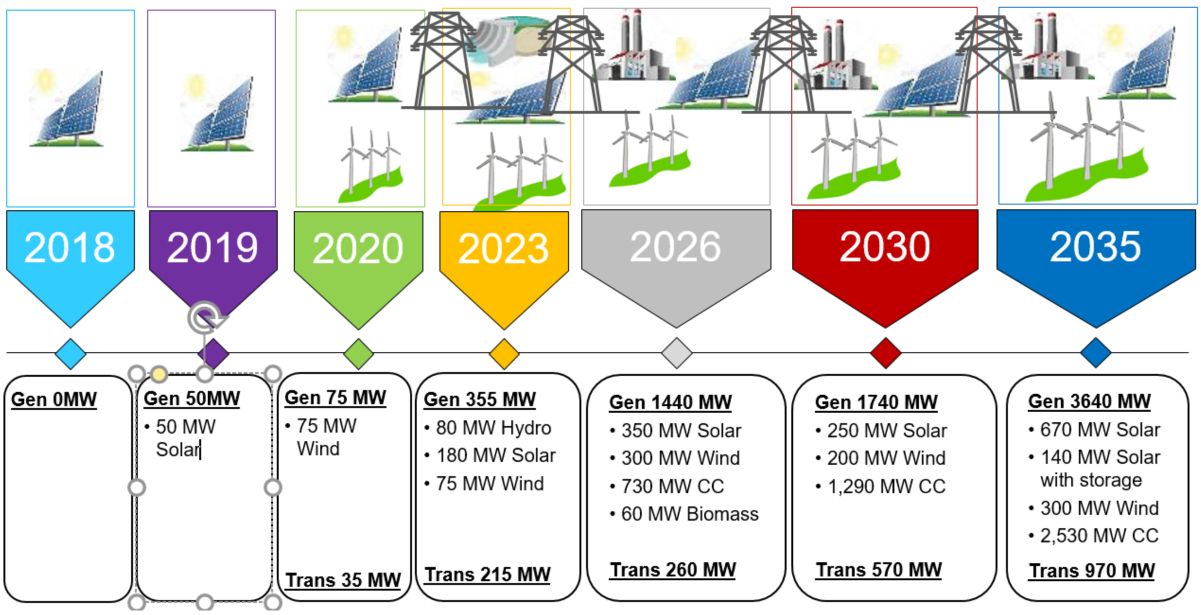
	Cost Metric	Reliability Metric	Resilience Metric	Local Environment Metric	Land Use Metric	Climate Metric
Indigenous Resources Strategy II	0.0	3.6	2.0	5.1	10.0	3.4
Business as Usual Strategy I	0.2	2.1	10.0	9.1	7.3	8.8
Export Oriented Strategy V	3.1	0.0	9.6	10.0	7.3	10.0
Diversified Resources Strategy III	7.4	1.8	4.5	7.2	0.0	7.0
Enhanced G-NDC Strategy IV	10.0	10.0	0.0	0.0	7.5	0.0

Figure 73: Least-Regrets Build Plan



The Least Regret Portfolio discussed above is optimised under the reference demand assumptions, and all of the other reference assumptions discussed in chapter 6 and section 7.2.2. 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 21 and Figure 22 in Chapter 6.3.3). The results of the Least Regrets strategy optimized under the High Demand case is shown in Figure 74.

Figure 74: Least Regret Build Plan Under High Demand



A comparison of Figure 74 and Figure 73 shows that build profile for both the Reference and High Demand cases are the same until 2023. Starting 2023, there is more renewable energy being built starting in 2023, and a much larger combined cycle plant (730 MW) is needed by 2025-2026.

Beyond the 10-years timeframe, significantly higher number of new plants are needed to meet the High Demand case than the Reference Demand case, as expected. 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, then the updated IPSMPs in the future will show the need to build more new plants.

7.4.1. Gas Demand in the Least Regret Strategy

Reference Electricity Demand Case

With increasing electricity demand, the demand for natural gas from power plants in both the Takoradi and Tema enclaves increase gradually from 2018 through to the end of the planning period. See Figure 75.

The demand for gas for power plants in Takoradi rises from about 155 MMcfd (annual average) in 2018 to about 180 MMcfd by 2019, following which the gas demand decreases in Takoradi such that it is about 130 MMcfd by 2027 (particularly as Karpowership ends its contract with ECG). 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 starts from about 60 MMcfd in 2018 and rises to about 260 MMcfd by 2027.

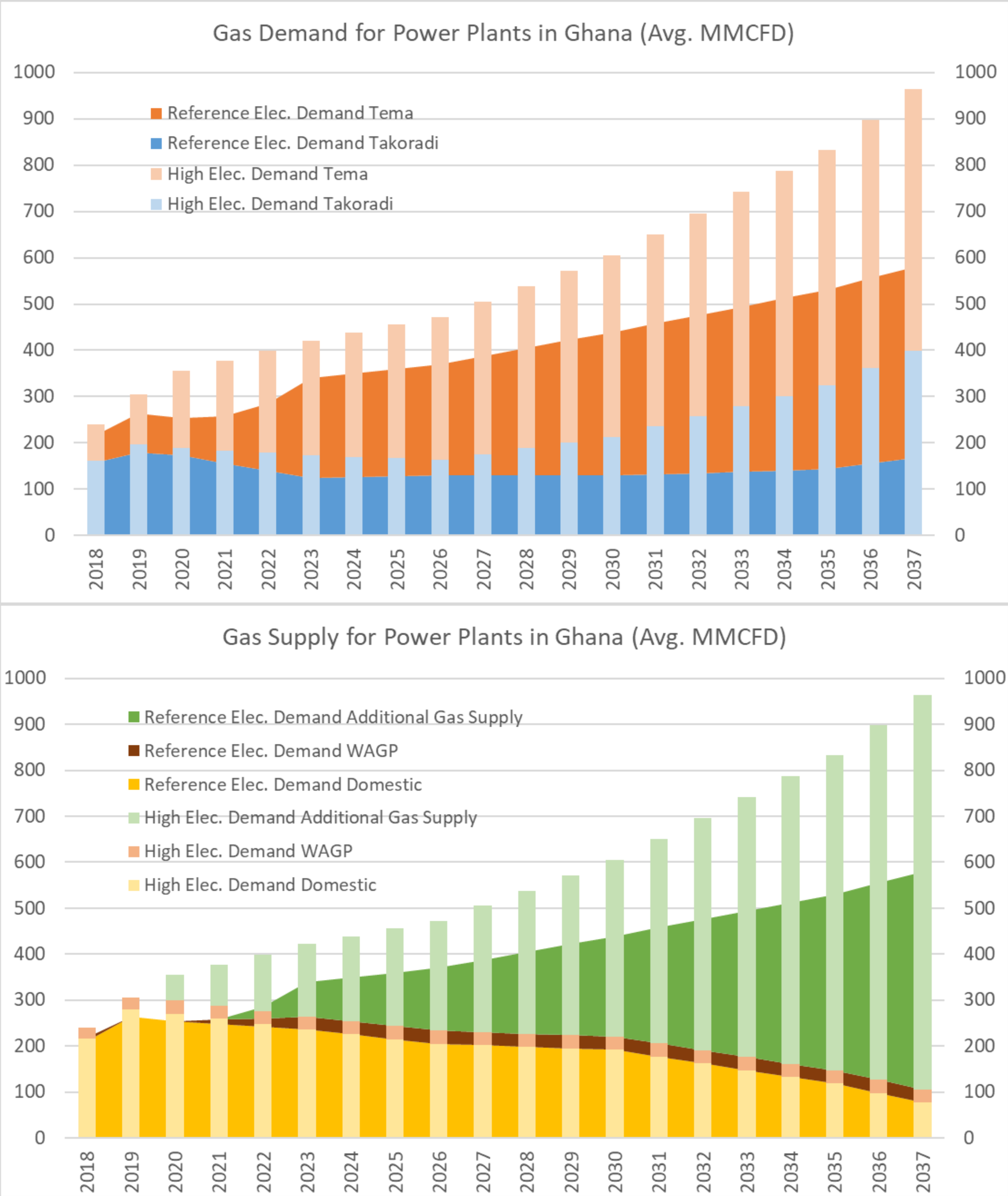
The total gas demand in Ghana continues to rise in the Least Regrets run from about 215 MMcfd in 2018 to 390 MMCfd MMcfd in 2027 and 580 MMcfd in 2037.

As noted earlier, the gas supply is primarily from domestic gas production, WAGP and LNG. LNG volumes are a proxy for additional supply from WAGP or greater domestic production.

High Electricity Demand Case

Under a high electricity demand case, the total gas demand in Ghana rises from 240 MMCfd in 2018 to 500 MMcfd in 2027 and 900 MMcfd in 2037. If the electricity demand is very high (as discussed in Figure 21 and Figure 22 in Chapter 6.3.3), then gas demand in both Tema and Takoradi continues to rise over time. Tema demand is about 65% of total demand in 2027, and 60% in 2037. See Figure 75.

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



7.4.2. Variable Renewable Energy Capacity 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.

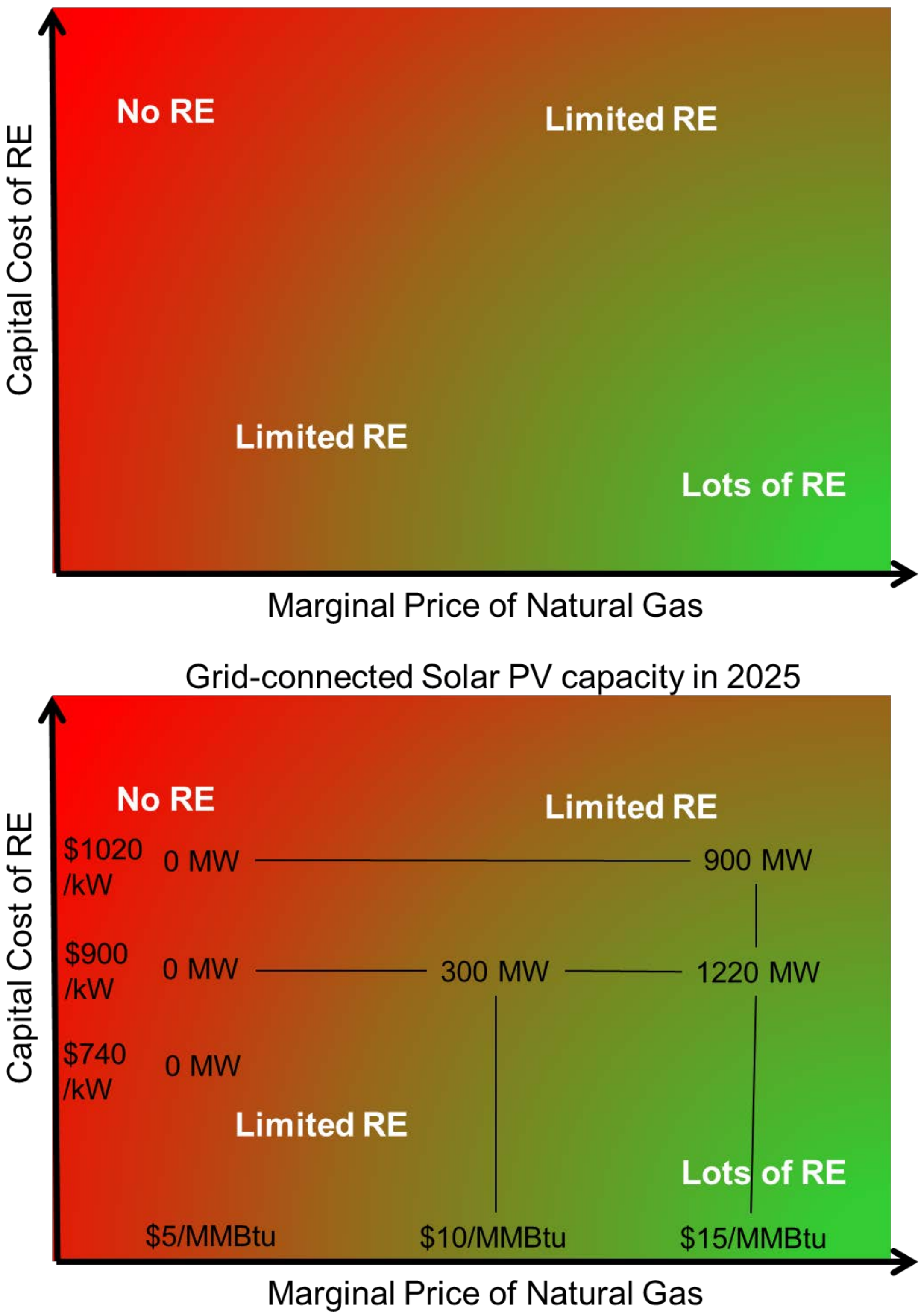
If the marginal cost of the delivered natural gas is high, this then presents a greater opportunity for vRE capacity to come into the generation system on a pure economic basis, especially if the capital cost of the vRE technologies are also low. On the other hand, if the cost of gas is low and/or capital 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.

Figure 76 illustrates this behavior. The x-axis of the graph is marginal cost of the delivered natural gas in $/MMBtu, and the y axis is the capital cost of solar plants. The green and red colors in the graph show the areas of the graph that favor vRE (green) on an economic basis, and the areas that do not favor vRE (red).

As an illustration, the total new solar PV capacity of 300 MW from the least-regrets strategy at 2025 is shown in the bottom graph of Figure 76, where the marginal cost of natural gas (from LNG, as shown in Figure 38) is around $10/MMBtu. If the price of gas is significantly higher ($15/MMBtu, as shown in Figure 40), then the model suggests that nearly 1220 MW of solar PV could be built by 2025, in order to reduce the total system cost. On the other hand, if the price of gas is quite low (at $5/MMBtu, as shown in Figure 40), no solar PV plants can be built on a pure economic basis. At the low gas prices, even if the solar PV cost were to decrease by about 20%, no solar PV plants can be built. This indicates that solar PV capital costs have to decline significantly at low gas prices in order to become economic.

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. Therefore, there is uncertainty about the cost of natural gas supply to power plants in the future. **Therefore, 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.

Figure 76: Economically driven RE-builds as a function of RE capital cost and Marginal Price of Natural gas: Top: General schematic; Bottom: 2025 Grid-based Solar PV builds



7.4.3. Update of the Least-Regrets Strategy for the 2018 IPSMP Build Plan

In November 2018, the Least-Regrets strategy (i.e., Strategy II) was updated to account for specific changes that have happened since the IRRP project finalized the assumptions for the modelling by the middle of 2017:

- **No Renewable Energy Penetration targets** are imposed, although as in Strategy II, a small amount of biomass and small hydro plants are forced in by policy. See Table 23.
- **Sankofa production** delayed till November 2018.
- **Maximum gas volume from WAGP** is limited to 60 MMCFD in 2018, rising to 84 MMCFD from 2019 onwards. However, the model is allowed to choose how much WAGP can be consumed based on gas demand from the power sector.
- **West-to-East gas** flow starts in 2019 instead of latter part of 2018 (because Takoradi-to-Tema gas reverse-flow project has been delayed until 2019.
- **AKSA:** Changed the total installed capacity to 370MW with a net dependable capacity of 350MW (initially, the net dependable capacity was assumed to be 375MW—see Table 10). AKSA Phase 1 installed capacity was kept at 250 MW until 01/01/2019, when the Phase 2 comes online for a total installed capacity of 370 MW. All of the AKSA units retire on 1 November 2023, based on discussions with ECG.
- **Karpowership** remains in the Southeast zone with an increased net dependable capacity of 450 MW, from 1 October 2017 onwards.
- **Karpowership** then moves to Southwest zone by middle of 2019, and is retired on 1 August 2027.
- **Early Power**: Phase 1 of Early Power comes online at 1 September 2019 at 140 MW (combustion turbine or simple cycle), and then increase to 190 MW (combined cycle or steam add-on) on 1 January 2021. The Phase 2 of Early Power (which increases the total capacity to 390 MW) comes online on 1 December 2023.
- **Cenpower:** Online date changed 1 January 2018 to 1 February 2019
- **Amandi:** changed online date from 30 April 2019 to 1 December 2019
- **Trojan:** Trojan 1, 2A and 2B were retired on 31 December 2018
- **TAPCO:** As before, TAPCO units are expected to be re-licensed and they continue to operate throughout the modelling period.

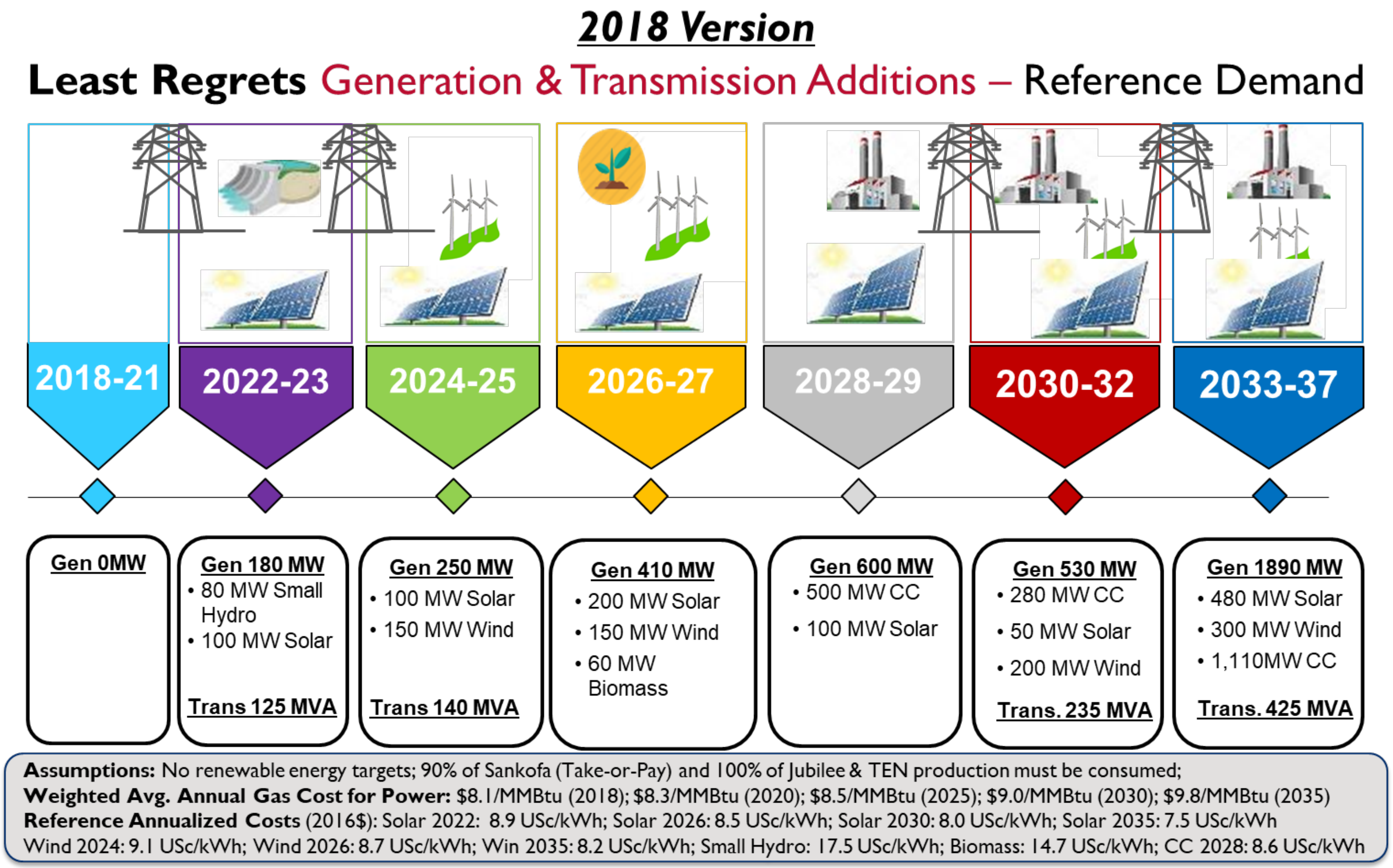
The rest of the assumptions remained the same, including the demand, total reference case gas production from 2019 onwards (Figure 36), the 90% Sankofa take-or-pay obligation, the fuel prices (Figure 38), and the new build cost and performance (Table 14).

With the changes listed above, a new build plan was developed as is shown in Figure 77 and is also reproduced in Volume 1. The key takeaways from the 2018 IPSMP Build Plan are:

- Do not build any new plant until 2022-23.
- New gas-based power plants (beyond the ones under construction) are **only** required by 2028, when Karpowership is removed from the system.
- If TAPCO is retired early, then a new replacement gas plant would then be needed to replace the retired TAPCO plant by the mid-2020s.
- Small hydro plants and biomass plants in the mid-2020s can be supported, based on a policy decision to deploy them. However, as shown in Figure 77, the reference cost of generation from these plants are high.
- Given the high and increasing price of natural gas and demand growth, solar and wind energy plants are economically feasible starting in 2023. The projected vRE capacity increases over time due to rising costs of natural gas (Figure 77 shows the weighted average cost of natural gas for conventional plants, as modeled).

- Demand growth allows for full consumption of Jubilee and TEN gas, and the 90% take-or-pay obligation of Sankofa production, assuming that the projected production volumes are consistent with Figure 36. If there is more production from Greater Jubilee, then there is no need for vRE in early 2020s.
- There is time (given the no build recommendation until 2022-23) for the modelling inputs to be updated in 2019 to better determine the specific timeframe when new vRE plants are needed.

Figure 77: Updated 2018 Version of Least-Regrets Build Plan



8. KEY FINDINGS AND RECOMMENDATIONS

8.1. 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.

8.1.1. Generation and Demand

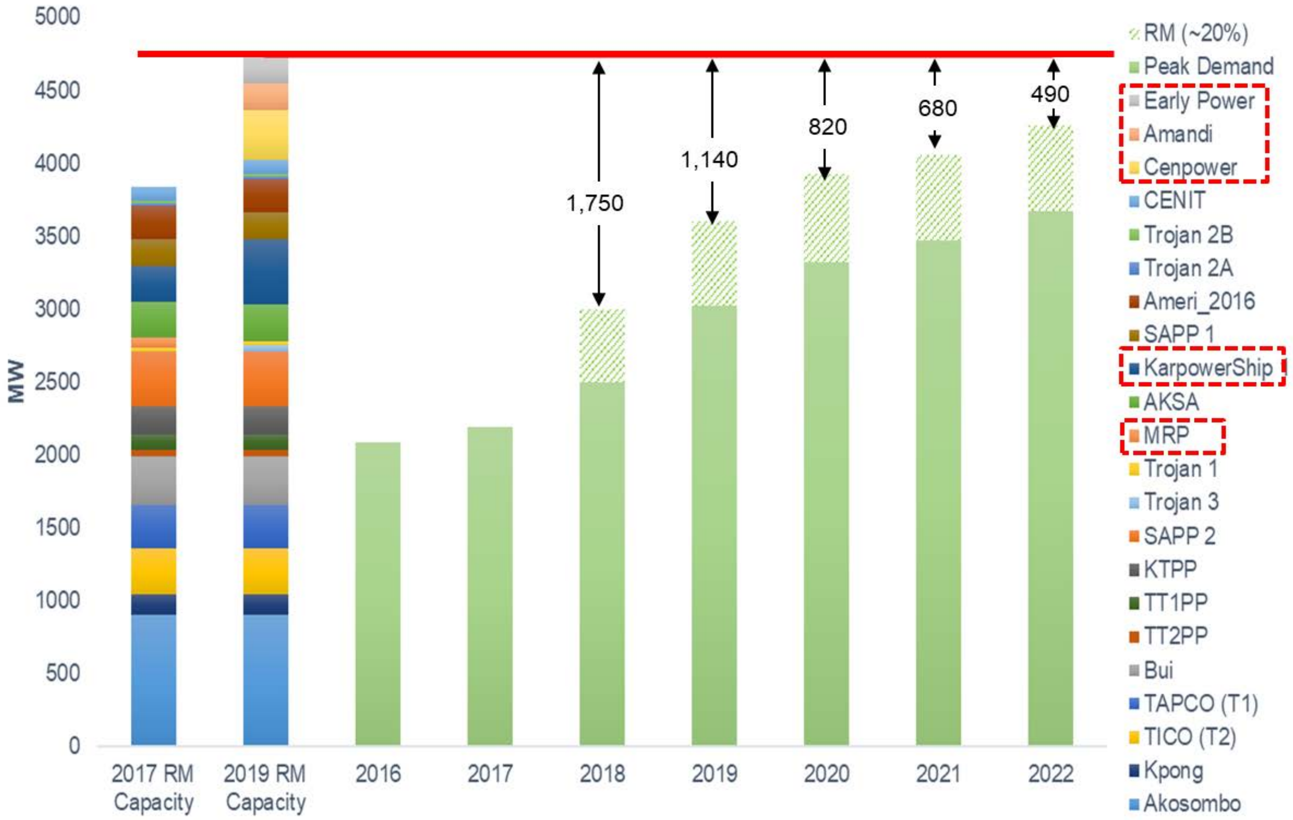
1. The modelling results confirm that there is significant overcapacity in Ghana, at present, and that this overcapacity is expected to continue for the next 5–7 years as the power plants currently under construction (see Table 11 in Section 6.4.1) are commissioned in 2018 and 2019. The net dependable capacity, as of December 2017, was 3971 MW[63], but expected peak demand in 2018 could be between 2450 and 2600 MW.[64] Therefore, the reserve margin in 2018 is significantly higher than the planned reserve margin of 20%.[65] Furthermore, the overcapacity challenge situation is expected to continue into the mid-2020s. See Figure 78.
2. Additional conventional, thermal generation will not be needed until the mid-2020s in Ghana, due to the three combined cycle gas-fired plants (Cenpower, Early Power, and Amandi) that are already under construction. These plants will add a combined net dependable capacity of 700 MW when they are fully commissioned by the end of 2019.
3. It is important to recognise that having sufficient installed capacity does not, by itself, equate with energy security; availability of natural gas, the ability to purchase liquid fuels, and the utilisation of the power exchange with Ghana's neighbours are necessary for ensuring operational success. Sufficient reservoir capacity in the Akosombo Dam is another metric for assessing security. Therefore, adding more imported fuel-based capacity will only make Ghana's electricity system less secure, in the longer run.
4. Fixed capacity charges for existing and under-construction plants will have to be paid by utilities (through consumer tariffs), whether or not these existing plants are dispatched, and therefore dispatch decisions need to be solely based on cost of generation.
5. Utilising Ghana's indigenous resources (i.e., small hydropower, renewables, and indigenous natural gas) is the ***Least-Regrets*** Strategy, primarily because it is the least-cost option 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. See Figure 77 in Section 7.4, which show the generation and transmission builds for the updated 2018 version of the Least-Regrets Strategy, under the Reference Case Demand projections.

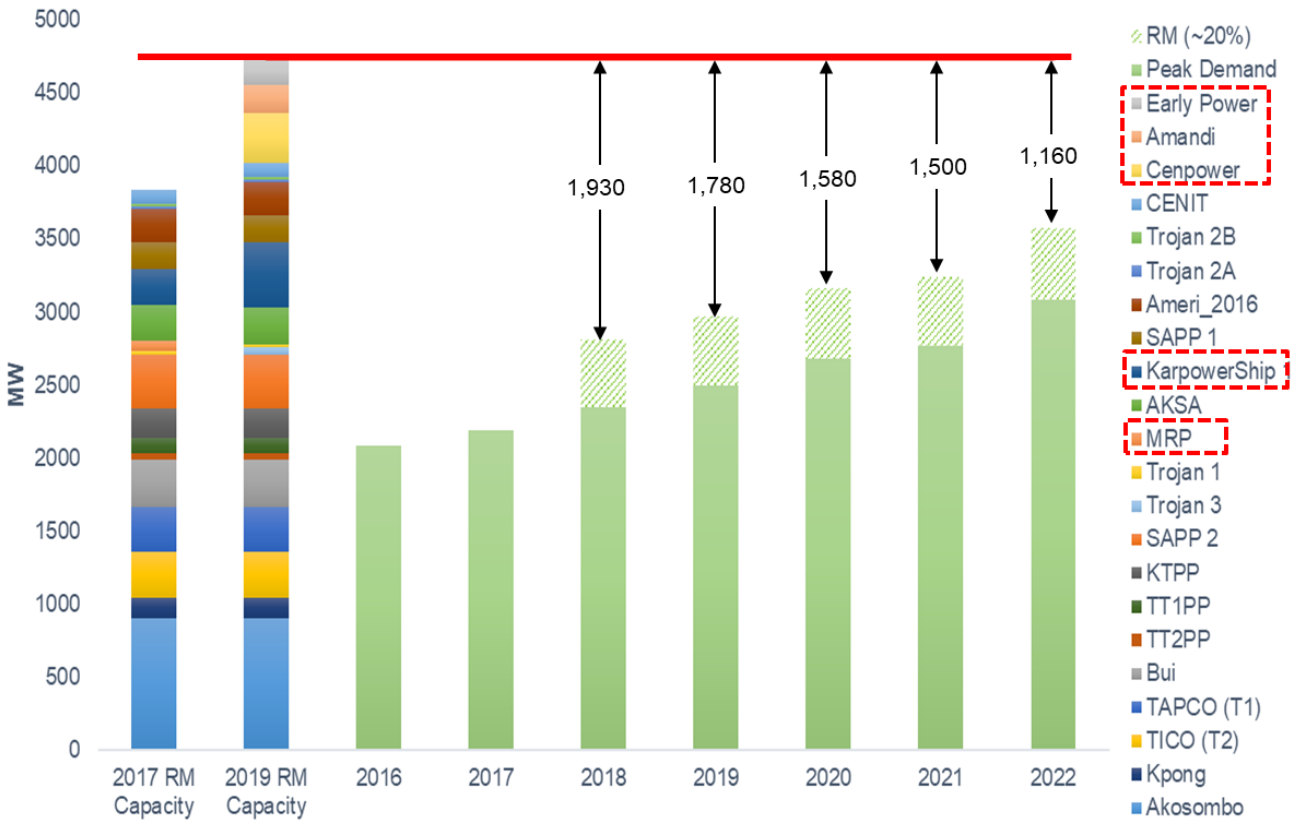
[63] Energy Statistics. 2018. Page 6, Table 3.1 (compiled by Energy Commission).

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

[65] 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 78: Medium-Term Supply-Demand Balance for Reference Electricity Demand (top) and High Case Electricity Demand (bottom)





6. Over the next 10 years (2018–2027), based on the updated 2018 Least-Regrets Strategy under the Reference Case demand projection, a total of about 800 MW of renewable energy (solar PV, wind, biomass, and small hydropower) and combined cycle capacity is only needed in 2028.

   - The builds for renewables and conventional thermal plants for the next 10 years and the following 10 years for both the Updated 2018 Least-Regrets strategy, the Least-Regrets and the Business-as-Usual (BAU) strategies are shown in Table 42. The updated Least-Regrets strategy has significant renewable builds because the generation costs from existing power plants rise over time. Under the High Demand Case, conventional builds are higher in the Updated Least Regrets case.

Table 42: Unplanned Builds in MW for Least-Regrets and BAU Strategies

Unplanned Builds (MW)	Reference Demand Case					
	Updated 2018 Least-Regrets (w/o RE target)	Updated 2018 Least-Regrets (w/o RE target)	Least-Regrets (with RE target)		BAU (with RE Target)	
	2018–2027	2028–2037	2018–2027	2028–2037	2018–2027	2028–2037
Renewable	840	1130	935	1230	920	1170
Conventional Thermal	0	2030	40	1600	450	1250
Unplanned Builds (MW)	High Demand Case					
	Updated 2018 Least-Regrets (w/o RE target)	Updated 2018 Least-Regrets (w/o RE target)	Least-Regrets (with RE target)		BAU	
	2018–2027	2028–2037	2018–2027	2028–2037	2018–2027	2028–2037
Renewable	990	1250	1160	1560	1300	1240
Conventional Thermal	870	4055	730	3820	760	3740

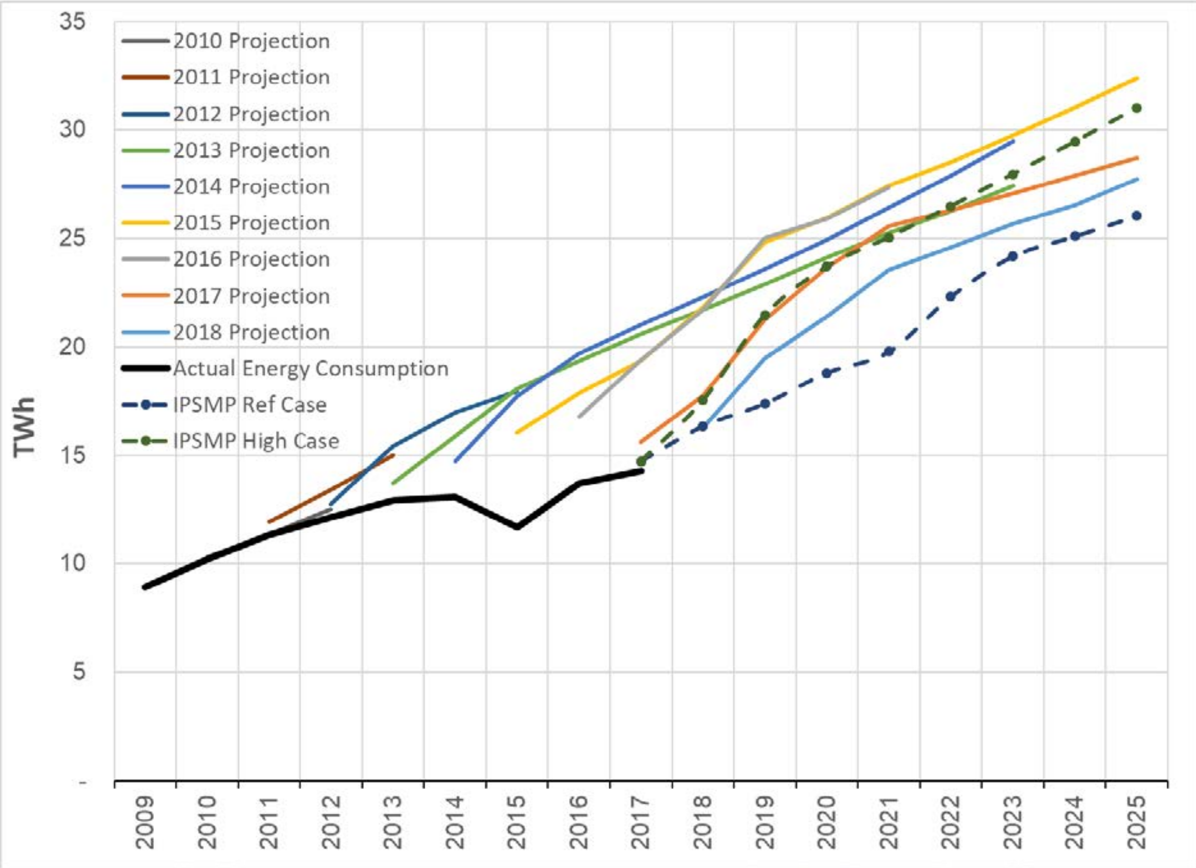
7. Demand growth is the major factor that determines how much new capacity is needed in the future. Therefore, a focused effort to better understand what the underlying factors are that determine demand growth (e.g., temperature-dependency, price-elasticity, granularity of sectoral and regional economic 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 79 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 GRIDCo estimated in the past. The reference case IPSMP forecasts are closer to the actual consumption. 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 79: Comparison of Annual Supply Plan forecasts over time, with IPSMP Forecasts



Source: Various Ghana Annual Supply Plan (from GRIDCo)

8.1.2. Renewable Energy

8. 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.
9. 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.
10. 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.

11. 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.
12. 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.
13. 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 have additional benefits such as irrigation and flood control.
14. In terms of land requirements, 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 purposes depending on the design of the mounting structures.

8.1.3. Conventional Power Plants

15. 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 42 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).
    - 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 BAU 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.

8.1.4. Transmission

16. 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.

8.1.5. Fuel Supply

17. Contractual requirements of the Sankofa take-or-pay agreement makes it essential for west-to-east flow of gas (through West African Gas Pipeline [WAGP] reverse flow) to be implemented mainly because of limitations in the capacity of the plants in the west (i.e., Aboadze power enclave) to fully utilise the region’s available gas. 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 utilise the Sankofa gas.

    - Reference production estimates of gas supply from Sankofa, TEN, and Jubilee is not sufficient to fully meet gas demand for power generation beyond 2023, considering gas demand in both the Eastern and Western power enclaves together. Consequently, additional gas is needed to support power plants in the Tema power enclave. This additional gas demand can be met by increased supply from WAGP, additional indigenous production, or LNG imports.
    - By 2035, demand for gas in the Aboadze power enclave alone increases beyond projected gas supply in the IPSMP Reference Case assumptions. Hence, additional gas supply would be necessary, and this supply could come from WAGP, additional domestic gas production, regasified LNG piped from the east to the west (subject to transportation costs), or a new LNG terminal in the west. It is expected that increasing supply from domestic resources or an existing LNG terminal will be cheaper than building a brand new terminal.

8.2. Recommendations for Implementation

8.2.1. 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, especially in the areas of end-use activities such as lighting, space cooling or air conditioning, refrigeration, water heating, and more generally, motors and compressors. Just as the massive exchange of 6 million compact fluorescent lamps (CFLs) for incandescent bulbs in 2007 and 2008 lowered the peak electricity demand in July 2008 by 124 MW[66], the use of light-emitting diode (LED) lamps, more efficient air conditioners and fridges/deep freezers can decrease the growth rate of electricity demand, keep carbon footprints down, and help businesses and homes to save money.
   – Recent analysis by the IRRP Project shows that nearly 30% of electricity consumption can be saved in commercial buildings through cost-effective improvements in lighting and cooling.
   – Substandard or non-energy-efficient appliances should no longer be permitted at the country's 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 could support distribution utilities by facilitating energy efficiency programmes that are revenue neutral.

   – Tariff-setting that is transparent and cost-reflective also facilitates the adoption of energy efficiency measures with minimal incentives.

4. The EC should expedite and expand the energy efficiency labelling programme for more appliances.

   – This will lead to broader implementation of energy efficiency and DSM programmes across a wider range of appliances.

8.2.2. Transmission

5. Expedite the review of the 2011 Transmission System Master Plan and its subsequent implementation. In the interim, preliminary results (see Appendix on Transmission Report in Volume 3) indicate the need to reinforce some sections of the grid.

   – The model assumptions behind the study for the 2011 Transmission Master Plan have changed. Developing new modelling assumptions is therefore needed to reassess the current configurations of the grid, and examine options for evacuating the additional generation from the new and planned generating plants to the load centres.

[66] Final Report – CFL Exchange Programme Impact Assessment, Jan 2009, Energy Commission Report.

6. Adopt a policy measure to double-circuit the high-voltage transmission line configurations to address future right-of-way (ROW) constraints in all new high-voltage transmission and sub-transmission lines.
   - By planning for double-circuiting of the new transmission lines, the ROW constraints in transmission expansion programmes will be mitigated. 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. Upgrade the lines from the Western region (Aboadze) to the Middlebelt area to address current transmission reliability constraints. Similarly, the link between Tema/Akosombo and Aboadze must be upgraded to increase the firm TTCs between the SouthEastGH and SouthWestGH zones.
   - Both the Eastern (Tema/Akosombo) and the Western (Aboadze) regions in Ghana are the major generation zones in the country. Hence, additional grid infrastructure upgrades are necessary to adequately transmit power during contingencies back and forth between these zones. This will also allow an increase in the TTCs to supply the Middlebelt and the NEDCo areas.
8. Close the eastern corridor loop from Kpandu-Kadjebi to Yendi through Juale (with or without the Juale hydropower plant).
   - Reliability of the transmission system would increase if the loop connecting the existing corridor in the Volta region is connected and closed with the transmission system in the northern part of Ghana. This will strengthen the NEDCo system by providing an alternate route to supply electricity to the region. The voltage-related losses in the NEDCo region would also decrease. In addition, the existing lines are already being upgraded to 161 kV, and this line upgrade project should be expedited.
9. Construct a substation around Pokuase to reduce losses.
   - 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 assist in determining the composite effect of proposed power plants on the grid, and with recommended mitigation measures for variable renewable energy projects that can help alleviate impacts on an aggregate level. Over time, as new solar power plants are built in the north, there will be changes in system losses for the NEDCo region. A study on the aggregate impact will provide an indication of 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.
    – Additional data from the weather systems 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.

8.2.3. Distribution Planning

12. Utilise information from smart meters and automatic meter readers (AMR) to implement options to reduce commercial losses.
    – Analysis of existing data collected by the AMR system used for the Electricity Company of Ghana's (ECG's) special load tariff (SLT) customers, boundary meters, and other smart meter data will support the development of options to reduce losses and improve the collection rate of the distribution companies. Such analyses will also provide the most recent data from these customers for future demand forecasting.
13. Coordinate the connection of new customers more effectively to avoid unmetered customers.
    – In the past, some communities were connected to the grid without proper metering arrangements and when the bills accumulate it becomes very difficult to settle. Better coordination is necessary between the agencies doing the grid expansion or rural electrification projects, and the distribution companies that are in charge of the operation and maintenance of the newly added network. Such coordination of new connections will help prevent unmetered customers.
14. Limit situations where customers are put on flat rates.
    – Some customers are put on flat rates due to shortage or under-stocking of metres. Better inventory management can prevent this situation. Further, when it takes more than a year to provide a meter, it is advisable to review the consumption pattern of the customer to arrive at a more realistic "flat rate".
15. Use higher voltages for sub-transmission lines to reduce technical losses. As GRIDCo upgrades its 69kV network to 161kV, ECG should be allowed to operate some of its sub-transmission networks at 69kV in addition to 33kV where these lines traverse long distances.
    – 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. Extend ECG's reliability assessments to more regional capitals and ECG service areas.
    – ECG has conducted reliability assessments for Accra as reported in the 2017 ECG Accra Reliability Assessment (Sub-Transmission and Distribution) report. This is commendable and should be extended to more regional capitals. By extending the

reliability assessment to more cities, the distribution planning in those towns and cities will be improved.

17. NEDCo needs to conduct load flow analyses in heavy load centres like Sunyani, Techiman, Wa, and Bolgatanga.
    – NEDCo has carried out load flow analysis for Tamale in 2016. Similar studies should be carried out in other major load centres, as this will improve distribution planning in other towns and cities.
18. Develop an integrated SCADA system across all utilities in Ghana.
    – An integrated SCADA system will help ECG monitor the distribution network more closely, thereby reducing outage times and times for restoration. An assessment for the potential of a SCADA system for NEDCo should be carried out, with an initial pilot in Tamale, to improve the monitoring of the distribution network so as to reduce outage durations. NEDCo currently has no SCADA or distribution automation systems (DAS). Implementation of both the SCADA and DAS have faced funding constraints. NEDCo has, therefore, recommended a pilot in Tamale and also included a SCADA system in the funding request to the Millennium Challenge Corporation (MCC).
19. Coordinate the deployment of solar PVs at the 33-kV and 11-kV voltage levels with GRIDCo from the planning stage to operation and maintenance.
    – Uncoordinated planning and installation of solar PVs in the past created unexplained variations in loads at substations to which these solar PVs were connected.
20. Carry out studies to determine localities where rooftop solar PVs installations can result in significant loss reduction.
    – This could be one of the non-wires alternatives in addressing low voltages and high losses and even grid extensions.
21. Coordinate the use of GIS data for planning, operations, and maintenance of distribution service assets, in order to save costs and avoid duplication of effort.
    – GIS capabilities not only enhance operations and maintenance of distribution systems, but will also assist in the expansion planning or upgrades and in loss reduction programmes. This can help in capturing consumption data that is key to load forecasting and expansion planning. A GIS system can be incorporated into an asset management and inventory system to transform the distribution network. This can be further improved with a SCADA monitoring system—at least in the urban centres—to improve efficiency.

8.3. OTHER ISSUES

Emission Control

22. EPA 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 have sufficient and secure funding to be able to carry out their mandate and support recruitment and training of the required manpower as well as the provision of tools and equipment.

Rates/Ratemaking

24. PURC must exhibit transparency 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), to minimise public outcry at times of tariff reviews and quarterly adjustments.
    - These quarterly adjustments should be strictly and transparently followed 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. All subsidies should be explicitly specified.

Financing

25. The Ministry of Finance should consider whether it is prudent to continue to offer government support to new power plant developers in a situation of overcapacity.
    - When the situation changes and there is the real need to attract investment to carry out capacity expansion, the need for a put-call-option agreement (PCOA) or any other suitable form of guarantee/government support should be considered on a case-by-case basis. Such support can be part of the procurement process.

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, 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).

9. 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.

Hence, 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 43: Recommended Membership of Power Planning Technical Committee

Energy Commission (Co-Chair)
GRIDCo (Co-Chair)
VRA, BPA (Hydro)
ECG, NEDCo, EPC
PURC, MoEn
EPA, MESTI, MoF
GNPC, GNGC, NPI
Co-opted members, as needed (e.g., GSS, Ghana Me)

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

This new **PPTC** (to be formed by the Ministry of Energy, in coordination with the EC) should retain the same membership composed of representatives from various sector agencies (see Table 43). In addition, additional members can be invited into the PPTC, as needed, for specific activities.

This standing PPTC should be **jointly chaired** by EC and GRIDCo. 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.

The PPTC, as part of its mandate, 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 theAnnual 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 44: 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)

9.1. 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 2018, the various institutions in the energy sector are expected to follow an integrated and collaborative, rather than silo-type, approach in undertaking energy planning activities. This will require a shift in the traditional planning roles that the various sector institutions play currently.

9.1.1. 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.

9.1.2. 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 renewable energy penetration targets for planning, as the grid becomes more resilient and intermittency gets moderated as a result of new developments in renewable energy technologies.

9.1.3. 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, 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.

9.1.4. 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.

9.1.5. 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 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.

9.1.6. 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.

9.1.7. 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.

10. Recommended Framework for Future Procurement

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[67] and higher electricity prices.[68]

10.1. Recommended Procurement Plan

30. Future procurements of additional generation capacity to meet increasing demand should be based mainly on the 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.

10.1.1. 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

---

[67] Current installed generation capacity is about twice the country’s peak demand.

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

Procurement of Electric Power Generation from Wholesale Suppliers of Electricity" (June 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.
    - The EC can also direct the regulated off-taker 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).

10.1.2. 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.

10.2. Institutional Roles in Procurement for Additional Capacity

10.2.1. 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.

10.2.2. 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.

10.2.3. 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.

10.2.4. 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.

10.2.5. 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.

10.2.6. Funding of New Power Projects

The financial plan for funding capacity expansions or new capacity additions should be open to all funding sources including export credit funds and private investors (whose main incentive will be to achieve an agreed rate of returns on their investment).

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.

10.2.7. Credit Enhancement for New Power Projects

As a result of the current situation of excess generation capacity, there is no need for the Government of Ghana to bear any risks in terms of sovereign guarantees or PCOAs. Instead, more effort should be focused on making sure that the off-takers remain credit worthy to enable them pay off all their debts. The ongoing power sector debt restructuring measures coupled with the proposed establishment of escrow accounts to apportion payments to suppliers should help address credit risk issues.

11. 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.

11.1. 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 it to collect more granular data (e.g., heat rates, prices of fuels, plant availability, emissions rates) from the 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 the general impacts of solar PV installations and net-metering (currently being piloted) 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. Integrate time-of-use rates into planning.

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

12. 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.

12.1. 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 45 summarizes the various risks that have been considered in the IPSMP modelling and the relevant mitigation measures.

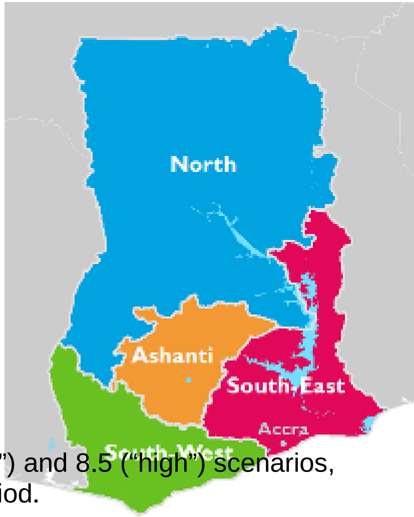
Table 45: Risks and Mitigation Options for Ghana's Power Sector

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.

12.2. 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 80. 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 80: 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.[69] Change in annual precipitation is more uncertain, as models disagree on the 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

[69] 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.

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.[70]

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 81). 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.[71] Types of 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

[70] 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.

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

sectors.[72] 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 46. 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.[73]

Figure 81: 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 46: 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.

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

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

[73] UNEP and UNDP 2016.

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 47, Table 48, and Table 49, show some of the illustrative adaptation options for generation, transmission and distribution, and DSM.[74] Table 50 shows the estimated costs of several adaptation strategies that could be relevant for Ghana's power sector.

[74] 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.

Table 47: 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
		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 48: Transmission and Distribution 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 49: 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

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

Table 50: Estimated Cost of Adaptation Strategies

12.3. 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 ICF for technical support
11. Cost of renewal of software licenses

Table 51 summarises the potential mitigation options to deal with the various internal and external risks that could affect the implementation of the IPSMP recommendations.

Table 51: 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 ICF	▪ Sustain capacity building for power sector agencies from ICF before the IRRP Project ends. ▪ Ensure post-IRRP relationship between ICF and Ghana Power sector agencies is mutually beneficial.
8	Software licence renewal costs	▪ USAID could cover the costs of the 2020-2022 license renewal for IPM. ▪ GRIDCo and EC, on behalf of the PPTC, could procure future annual renewals.