



INVESTIGATING THE USE OF SHORT-TERM ELECTRICITY TRADING TO
ENCOURAGE VARIABLE RENEWABLE ENERGY DEVELOPMENT IN THE
EASTERN AFRICAN ELECTRICITY MARKET

Dissertation Manuscript

Submitted to Unicaf University in Zambia
in Partial Fulfilment of the requirements
for the degree of

Doctor of Philosophy (PhD)

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December 2025

Approval of the Thesis

INVESTIGATING THE USE OF SHORT-TERM ELECTRICITY TRADING TO ENCOURAGE VARIABLE RENEWABLE ENERGY DEVELOPMENT IN THE EASTERN AFRICAN ELECTRICITY MARKET

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Doctor of Philosophy (PhD)

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Abstract

INVESTIGATING THE USE OF SHORT-TERM ELECTRICITY TRADING TO ENCOURAGE VARIABLE RENEWABLE ENERGY DEVELOPMENT IN THE EASTERN AFRICAN ELECTRICITY MARKET

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The Eastern Africa Power Pool (EAPP) encompasses thirteen member countries with substantial but largely untapped Variable Renewable Energy (VRE) potential. Electricity trade currently relies on long-term bilateral power purchase agreements between state utilities. These arrangements are not suited to the short-term variability of wind and solar generation and are unable to provide the pricing signals needed to attract private investment. With the EAPP scheduled to launch a day-ahead wholesale market in 2026, this study provides timely quantitative and qualitative evidence to inform its design.

Three research questions were addressed: how electricity is traded globally and in Eastern Africa; how a wholesale market would be affected by increasing VRE penetration; and how accurately the simulation models EAPP short-term trading dynamics.

A sequential explanatory mixed-methods design was used. Agent-based simulations using the AMIRIS model modelled five EAPP countries, Kenya, Uganda, Tanzania, Ethiopia, and Rwanda, for 2025. They compared the base scenario (5.5% wind and solar share of installed capacity) against a high-VRE scenario (24.2%). Three sensitivity scenarios examined geothermal dispatch priority, intermediate VRE penetration, and the capacity threshold at which mean market prices turn negative. Eleven key informants from regulators, utilities, generators, and the EAPP Secretariat validated model assumptions and findings through semi-structured interviews.

Market structures across the five countries range from vertically integrated monopolies to partially unbundled frameworks. The simulation found that a day-ahead market would reduce average dispatch costs. Under the base scenario, the average clearing price was 67.5 EUR/MWh with VRE supplying 85% of energy. In the high-VRE scenario, the mean price collapsed to -295.57 EUR/MWh, with VRE supplying 99% of energy, and prices negative in 77% of hours. The optimal-VRE scenario identified 18.6% of the planned high-VRE increment as the ceiling beyond which mean annual prices turn negative. Quantitative validation against Kenyan 2023 grid statistics achieved a 0.58% energy deviation. Qualitative review identified the infinite transmission assumption as the principal model limitation.

The study found that short-term trading would lower prices and expand VRE dispatch, but rapid unmanaged expansion produces sustained negative pricing and suppresses investment signals. Price floors, contracts for difference, geothermal dispatch guarantees, and staged capacity planning are necessary to sustain investment whilst delivering consumer welfare gains. This study contributes the first agent-based market simulation for the EAPP and a replicable methodology for identifying VRE absorption capacity in emerging wholesale markets.

Declaration

I declare that this thesis has been composed solely by myself and that it has not been submitted, in whole or in part, in any previous application for a degree. Except where stated otherwise by reference or acknowledgment, the work presented is entirely my own.

AI Acknowledgment

I acknowledge that I have not used any AI tools to create or produce any text or ideas related to any draft or final versions of the thesis. The AI tool Paperpal was however used to proofread the manuscript for grammatical and flow soundness.

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Dedication

To accept that we are just a speck in the universe, an existence in a fleeting moment, a passing cloud, and to do what we can whilst we can.

This work is dedicated to a better, self-driven livelihood for the people of Africa. In my own way I am contributing to bringing brighter days sooner.

To colleagues in the African power sector working to better supply, earn from the trade, and inspire better livelihoods.

To added value in our efforts to improve the electricity sector in Eastern Africa.

Acknowledgements

This research has benefited immensely from the support of my supervisor Prof. Jairo Montoya Torres. I acknowledge the time spent reviewing manuscripts and giving feedback to my work. I also acknowledge the support from the various sector experts that agreed to participate in interviews and gave feedback to the study.

My appreciation also goes out to Christoph Schimeczek of the DLR for the support in handling the modelling and simulation in AMIRIS the backbone of this research.

I acknowledge my parents who made the sacrifices and laid the foundation for my education. My father Alfred Oduor Otieno, whom we lost over the course of this work, and my mother Ruth Anyango Otieno who formed much of who I am.

I acknowledge the support of my wife Ruth and children Nadezhda, Kwame, and Taye over the course of the research. The support through the many long nights of modelling, drafting and writing were invaluable.

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LIST OF ABBREVIATIONS

ABMS	Agent-Based Modelling and Simulation
AfSEM	African Single Electricity Market
AS	Ancillary Services
AU	African Union
CfD	Contracts for Differences
CH ₄	Methane
COMESA	Common Market for Eastern and Southern Africa
DRC	The Democratic Republic of Congo
DRES	Distributed Renewable Energy Sources
EAPP	Eastern Africa Power Pool
EEP	Ethiopian Electric Power Company
EPRA	Energy and Petroleum Regulatory Authority
ESKOM	Electricity Supply Commission of South Africa
EUR	Euros
ET	The Federal Democratic Republic of Ethiopia
FERC	The Federal Energy Regulatory Commission of the US
FiT	Feed-in-Tariff.
GWH	Gigawatt Hour
HFO	Heavy Fuel Oil
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IPP	Independent Power Producers
KE	The Republic of Kenya
KenGen	Kenya Electricity Generating Company
KETRACO	Kenya Electricity Transmission Company
KPLC	Kenya Power and Lighting Company
kWh	Kilowatt Hour
LCOE	Levelized Cost of Electricity
LNG	Liquified Natural Gas
LRMC	Long Run Marginal Cost
MWH	Megawatt Hour

MUSD	Million United States Dollars
MWH_Th	Megawatt Hour Thermal
NERC	North American Electric Reliability Corporation
NTCSA	National Transmission Company of South Africa
PPA	Power Purchase Agreements
RE	Renewable Energy
REG	Rwanda Electricity Group
RW	The Republic of Rwanda
SADC	Southern Africa Development Community
SAPP	Southern Africa Power Pool
SDG7	Sustainable Development Goal seven
SCADA	Supervisory Control and Data Acquisition
SUD	Sudan
TANESCO	Tanzania National Electricity Supply Company
TWH	Terawatt Hour
TZ	The United Republic of Tanzania
UETCL	Uganda Electricity Transmission Company Limited
UF	Utilisation Factor
UG	The Republic of Uganda
VRE	Variable Renewable Energy
WAPP	West African Power Pool

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CHAPTER 1 INTRODUCTION

CHAPTER 1.1: INTRODUCTION

The Eastern Africa region has abundant renewable energy resources. It has some of the continent's greatest hydropower, geothermal and solar potential. Straddling the equator, the region experiences among the world's highest solar irradiance, and its wind corridors rank among Africa's best, as evidenced by Kenya's high-capacity factor, Lake Turkana Wind Farm.

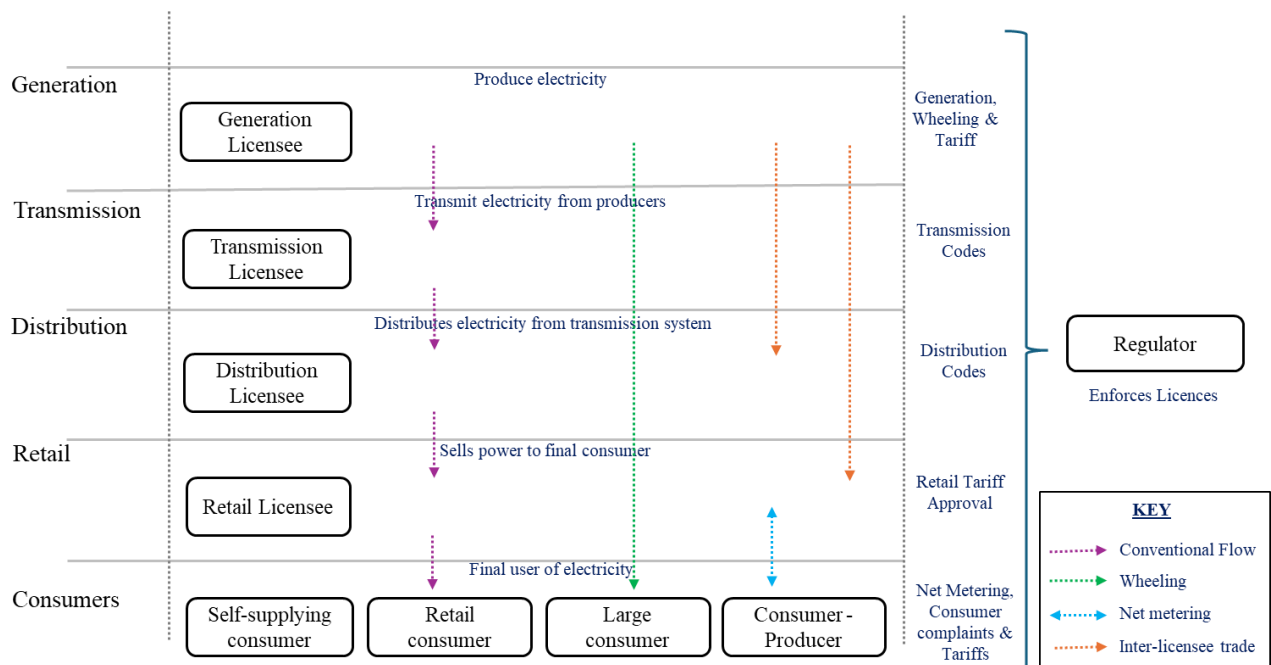
Eastern Africa like the rest of sub-Saharan Africa still suffers from low electricity access rates. Various actors have in the recent past started initiatives to extend electricity access for productive uses in the continent. The electricity consumption rates in the continent are also low. The gap between potential and reality is a market problem. The contracting frameworks through which electricity is traded in Eastern Africa are long-term bilateral power purchase agreements. These are negotiated between state utilities, and in some cases with independent power producers (IPPs). The fixed nature of these contracts implies that they are structurally unable to accommodate short-term variability of demand and supply. This means that short-term needs in Tanzania cannot be efficiently resolved by supply from Ethiopia. A long-term contract is required. Bilateral arrangements also do not provide transparent pricing signals that would attract private capital to the region's underdeveloped renewable resource base.

Electricity markets have evolved over the decades from vertically integrated, monopolistic structures toward unbundled, competitive wholesale arrangements (Stoft, 2015). The progression moves from a state utility controlling generation, transmission, distribution, and retail through a series of unbundling steps toward a competitive wholesale market. In the wholesale market, prices are determined by the intersection of supply and demand bids rather

than by long-term contracts overseen by a regulator (Kapika & Eberhard, 2013; Pinson, 2018). In the most advanced markets, this wholesale structure comprises sub-markets for day-ahead energy, intraday balancing, ancillary services, capacity, and transmission rights. Each of these provide price signals that guide investment decisions and allocate resources efficiently across a regional grid (Rudnick & Velasquez, 2018). An unbundled structure and its participants are illustrated in **Figure 1-1**.

Figure 1-1

Participants in an unbundled electricity market.



Note. Developed from (Stoft, 2015)

Competitive wholesale markets shift the risks of technology choice, construction cost overruns, and operational errors from consumer tariffs to the generators (Joskow, 2002). They ensure a market discipline that regulated monopolies cannot replicate (Traeger et al., 2017). Competitive markets create the pricing transparency necessary for variable renewable energy (VRE) to compete. Wind and solar, with near-zero marginal costs of generation, naturally lead

the merit order in a competitive day-ahead market. They dispatch ahead of fuel-dependent conventional generators and depressing average prices in the process. This price effect is beneficial for consumers but can damage the investment signals for all generators. This is especially so when the average market prices are below zero. Managing this tension is one of the central challenges this research addresses in the Eastern African Power Pool (EAPP) context.

Eastern African Electricity Markets

In the context of this research, Eastern Africa comprises the 13 member countries of the Eastern Africa Power Pool: Kenya, Uganda, Tanzania, Ethiopia, Rwanda, Burundi, the Democratic Republic of Congo, Sudan, South Sudan, Djibouti, Somalia, Egypt, and Libya. The electricity sectors of these countries sit at different points on the liberalisation spectrum. Uganda and Kenya have progressed furthest, having unbundled state utilities and admitted significant IPP participation. Ethiopia has separated its generator from its transmission and distribution operator. Tanzania, Rwanda, and the DRC retain more centralised structures with vertically integrated or partially unbundled utilities (Dagnachew et al., 2020; Mabea, 2020; Twesigye, 2022a). In all cases, wholesale power trade remains anchored in long-term bilateral contracts between utilities and power producers. Uganda's recent steps toward renationalising its distribution concession despite significant industry criticism illustrate the political fragility of reform progress even in the region's more advanced markets (Singh, 2025; Twesigye, 2022b).

The region's grids are small by global standards and partially interconnected. The pool's transmission infrastructure is organised into three synchronous clusters: the Kenya-Uganda-Tanzania cluster, the Ethiopia-Sudan-Egypt-Libya cluster, and the Rwanda-Burundi-DRC

cluster (Elabbas, 2023a). A non-synchronous high voltage direct current (HVDC) link connects the Kenya-Uganda-Tanzania cluster to Ethiopia, enabling bilateral hydropower imports (Gathuru et al., 2024).

Transmission line interconnections continue to be realised in the region. The 400 kV Kenya-Tanzania line was commissioned in late 2024. The 500 kV HVDC link between Ethiopia and Kenya is in service with Kenya currently importing 200 MW of Ethiopian hydropower. The Tanzania-Zambia interconnector that will join the EAPP with the Southern Africa Power Pool (SAPP) is under construction (AUDA-NEPAD, 2025; EPRA, 2025; Rubanda et al., 2024). The full envisioned interconnection network is depicted in **Figure 1-2**.

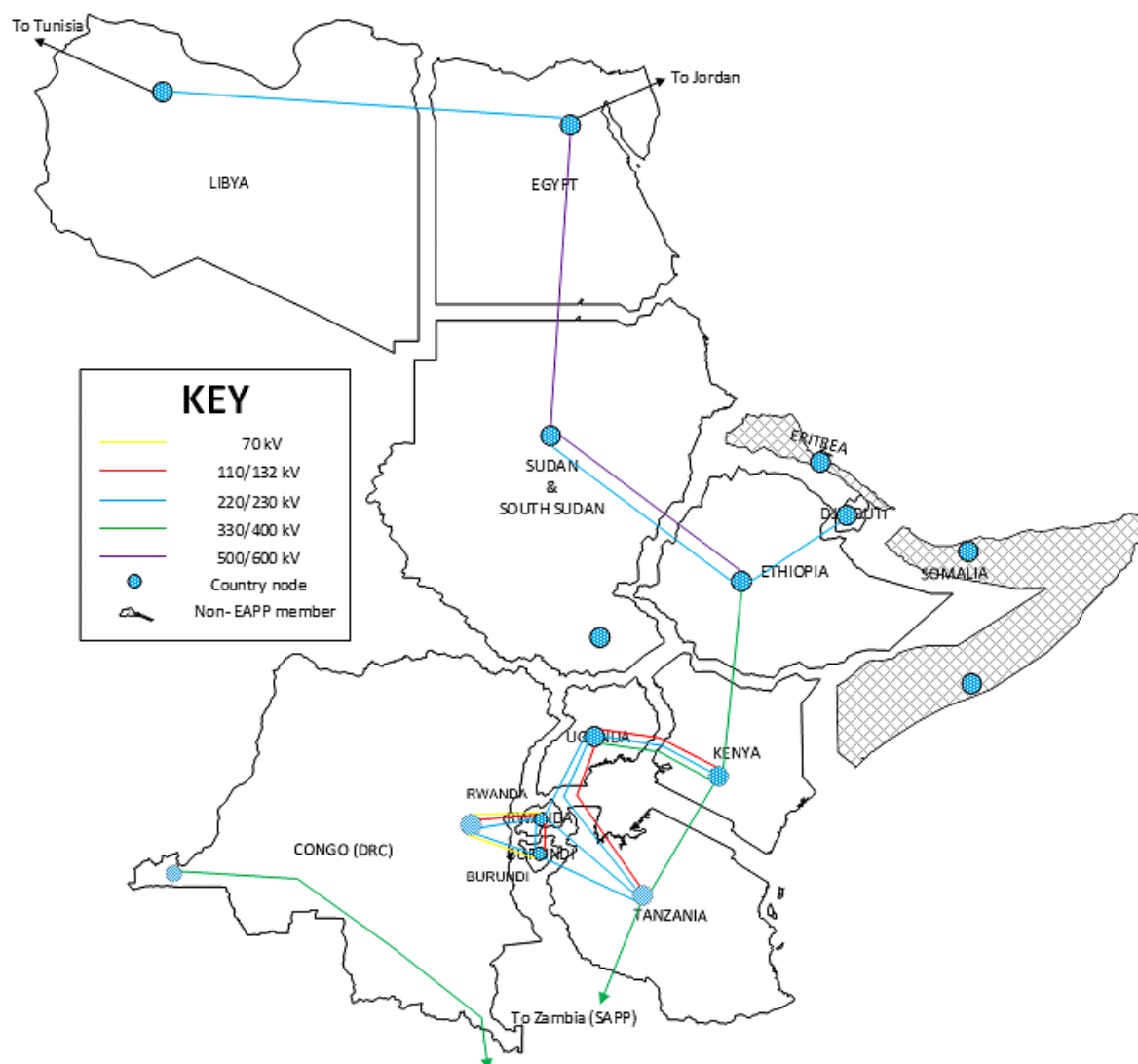
On the supply side, the region has been transformed by a wave of large generation projects. The 6 GW Grand Ethiopian Renaissance Dam (Gerd) on the Nile, the 2 GW Julius Nyerere hydropower station in Tanzania, and the 600 MW Karuma hydroelectric plant in Uganda have added thousands of megawatts to a region that previously faced perennial shortfalls (Rubanda et al., 2024). Kenya's geothermal fleet now exceeds 1,000 MW, the largest in Africa, providing reliable baseload generation regardless of weather. Wind capacity is also expanding in Kenya and Ethiopia. Solar installations are growing across all five sampled countries.

The region's renewable endowment (Kammen et al., 2015; Peters et al., 2024), combined with the new capacity now online, creates conditions for surpluses. These can only be efficiently utilised through regional trade. Under the bilateral framework, a country with excess generation must negotiate a new long-term PPA with a neighbouring utility in a process that takes years. A day-ahead market with interlinked electricity markets would resolve the

same trade-off in hours, providing the platform that this abundant renewable base requires to reach its potential.

Figure 1-2

A diagrammatic representation of the existing and expected interconnections in the EAPP.



Note. Developed from (Magochi, 2014)

Simultaneously, the costs of wind and solar generation have fallen dramatically. The global weighted average cost of onshore wind was USD 1,274/kW in 2022 and solar PV USD

857/kW. These represent declines of 69% and 89% respectively over the previous decade (IRENA, 2023). These cost reductions mean that new VRE projects in Eastern Africa can generate electricity at cheaper prices than peaking plants that currently set the marginal price during supply shortfalls. A competitive short-term market would allow this cost advantage to flow to consumers in the form of lower average electricity prices.

By the end of 2024, the thirteen EAPP member countries had agreed to launch a day-ahead market and had established an Independent Regulatory Board (IRB) (EAPP, 2024a, 2024b). The market is targeted for launch in 2026. It will initially allow state utilities to trade in the short term, with bilateral contracts coexisting alongside the day-ahead market as legacy PPAs run their course. It will be the second operational day-ahead market in Africa after the SAPP. This research is timed before the launch of the day-ahead market, adding perspective ahead of the launch.

Focus of the Research

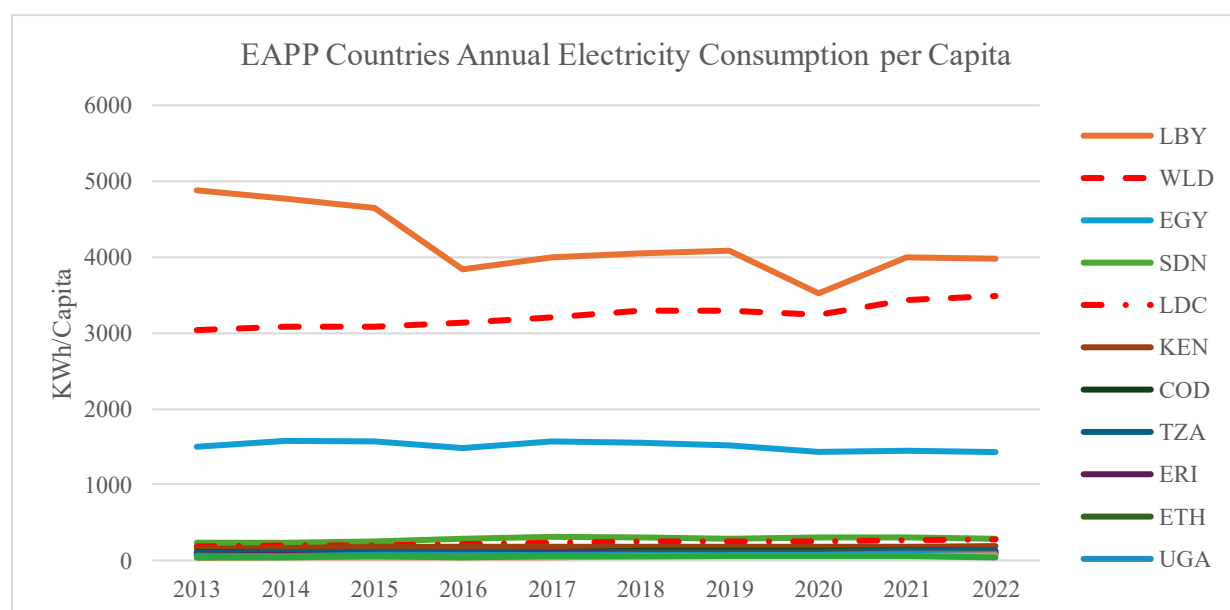
This research investigates the effects of introducing short-term day-ahead trading in the EAPP. It specifically focuses on how higher penetration levels of VRE would affect electricity pricing, the dispatch of power plants, and the stability of supply. EAPP-specific quantitative market research remains limited. Existing studies address technical grid expansion, bilateral trade economics, and institutional development (Elabbas, 2023a; The World Bank, 2022). This study provides quantitative evidence on the market outcomes that a day-ahead clearing mechanism would produce under different VRE penetration scenarios.

The EAPP region includes six of Africa's ten most populous nations, with youthful populations and high levels of unemployment and poverty. Eastern Africa's population of over 600 million is young, growing, and electricity deficient. Most EAPP countries have per capita

electricity consumption below 200 kWh per year, compared to a global average of 3,485 kWh in 2022 (The World Bank, 2025). Only Libya, Egypt, and Sudan exceed the threshold associated with the least developed countries. Sudan's position has likely deteriorated due to the ongoing conflict. The depth of this low electricity consumption rate across the region is illustrated in **Figure 1-3**. Access to reliable, affordable electricity is both an outcome and an enabler of economic development. It powers productive enterprise, manufacturing, cold chain agriculture, and the digital infrastructure that drives modern economic growth (Dagnachew et al., 2020; Ferguson et al., 2000).

Figure 1-3

Per capita consumption of electricity in the EAPP countries



Note. The data was sourced from the World Bank (The World Bank, 2025)

The research is situated within the United Nations Sustainable Development Goal 7 (SDG7) for universal access to affordable, reliable, sustainable, and modern energy by 2030 (World Bank et al., 2023).

This research investigates whether a short-term day-ahead wholesale electricity market in the EAPP would improve availability and pricing of electricity. The research additionally studies the effect that introduction of more variable renewable energy (VRE) would mean for the market's pricing, dispatch, and security of supply.

CHAPTER 1.2: STATEMENT OF THE PROBLEM

The current power trade in Eastern Africa is conducted through long-term bilateral contracts. These set the megawatt (MW) amount, time of delivery, duration, and price, typically for 10 to 20 years (Hausman et al., 2008). The EAPP is set to launch a day-ahead market that will see trade in hourly timeframes. This allows for flexibility to trade in surpluses or cover demand in the short term, as is usually necessary in markets with high VRE (Boscán & Poudineh, 2016; Rose & Perez-Arriaga, 2022). In day-ahead markets, prices are determined at the margin for each time interval. Wholesale markets are known to result in cheaper electricity prices (Leal et al., 2023; Sakaguchi & Fujii, 2021). There is a need to understand how market participants would interact within an EAPP wholesale market and the effects on pricing among other issues, considering higher VRE levels in the pool.

Competitive wholesale markets are still new to the African continent, with only the SAPP operating one and South Africa establishing one in 2025 (Elabbas et al., 2023). At the pool level, there are limited integrated market design frameworks for developing cross-country wholesale electricity markets. Recent studies have been conducted at the country level based on institutional reports (Csereklyei & Kallies, 2024; The World Bank, 2022). The EAPP market has limited focused research on market outcomes and how overall welfare will be affected by the introduction of a wholesale market, given the expanding VRE penetration (Elabbas et al., 2023).

Modelling is required to understand the outcomes of such complex systems. The modelling in the African electricity market has targeted the technical expansion of grids (voltage, power balance, and transmission limits) and not economic operations. These focus on optimal power flow modelling and not on the interactions of agents in a market. In African

market designs, agent-based modelling, an important approach for understanding interactions in a wholesale market, has been used in limited cases (Ferreira dos Santos & Tomé Saraiva, 2021; Trimarchi et al., 2025).

This study aims to characterise the electricity trade market in the EAPP under high VRE penetration. Modelling of the electricity network would be done to evaluate the operation of a short-term market and its effects on balancing demand and supply. The Agent-Based Modelling approach allows for the prediction of market participants behaviours in a short-term market regarding pricing and bidding strategies, capacity expansion decisions, and learning and adaptation (C. M. Macal & North, 2002). The model will not only aid in assessing the viability of a short-term market but also provide a platform for testing related regulations (North, Macal, et al., 2002).

As the countries of the EAPP come together to initiate short-term trading in electricity in an environment of higher VRE shares, there is a need to understand the implications for welfare and electricity supply stability.

CHAPTER 1.3: PURPOSE OF THE STUDY, RESEARCH AIMS, AND OBJECTIVES

The purpose of this research is to characterise and model a competitive wholesale electricity market in the EAPP using Agent-Based Modelling. This was undertaken to investigate the viability of using short-term trading to balance supply and demand and assess the effects of a higher penetration of variable renewable energy sources. Currently, power exchange is based on long-term bilateral contracts and inflexible transfers of electricity outside pre-agreed volumes (Rudnick & Velasquez, 2018). Power project investors in a short-term capable market would be able to directly market the electricity generated in short- and long-term markets. The EAPP will launch a competitive day-ahead market in 2026. Grids in the EAPP countries are increasingly adopting VRE for electricity supply (EPRA, 2025; Rotich et al., 2024). This study investigates the effect of higher penetration levels of varying renewable energy sources in the short-term market.

This study aimed to investigate the use of short-term trading to balance demand and supply and assess the impact of higher levels of VRE development in the EAPP. The research then aims to make recommendations relevant to theory, and policy on the EAPP. This was investigated using an agent-based model and key informant interviews. This study had three objectives, as described below.

1. To characterise the existing electricity trade market in Eastern Africa to enable an analysis of electricity trading. Market-related factors affecting the development of renewable energy projects in the EAPP and global markets are also investigated.
2. To develop a short-term trading model of the EAPP to investigate, through simulations, the effect of the introduction of short-term trading of electricity and higher penetration of varying renewable energy.

3. To validate the model assumptions, the simulation findings were compared with empirical data and experiences. The assumptions, results, and findings of the short-term modelling would be subjected to key EAPP stakeholders feedback for external validation and the addition of context.

CHAPTER 1.4: NATURE AND SIGNIFICANCE OF THE STUDY

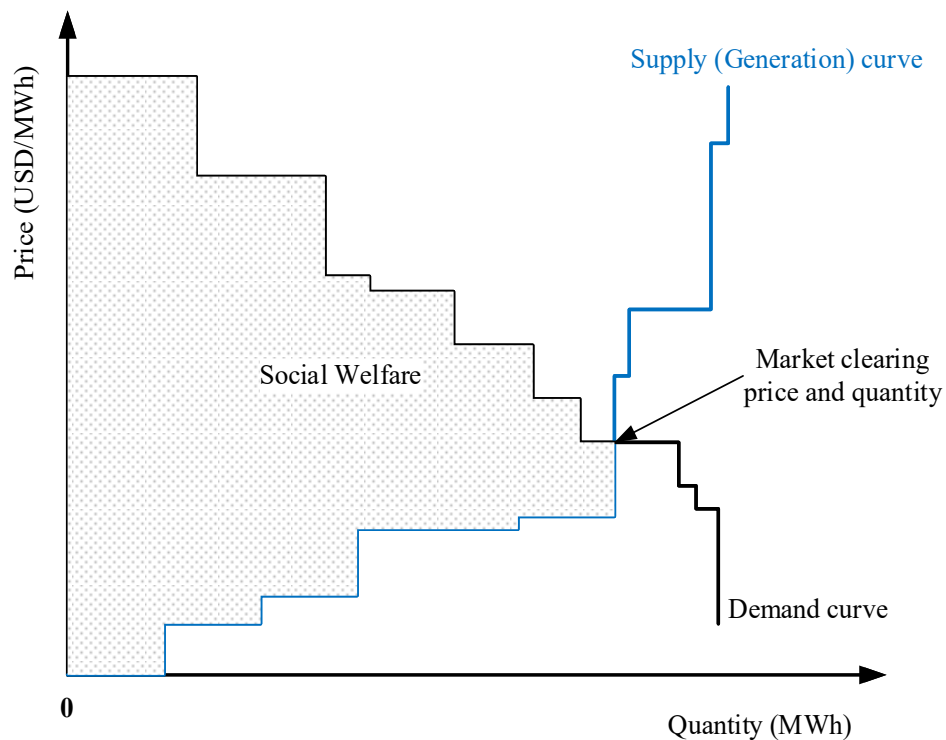
1.4.1. Nature of the Study

This study adopts a mixed-methods sequential explanatory design, beginning with a quantitative agent-based simulation and followed by qualitative key informant interviews. The interviews validate, contextualise, and extend the findings. Simulation is necessary because the EAPP day-ahead market does not yet exist and cannot be studied empirically (Kelton & Barton, 2003). The qualitative phase corrects for the simulation's structural limitations. This is mainly its single-zone, infinite-transmission assumption. The EAPP market has limited interconnection and has each country operating on their own bilateral pricing regimes. The qualitative feedback elicits expert judgement of practitioners working on the EAPP.

The AMIRIS model (version 2.0.0-alpha.33), developed by the German Aerospace Center (DLR) was the quantitative tool employed. The model was adapted for the EAPP by substituting the German 2019 reference scenario with the generation, demand, and resource data of a select five EAPP countries for 2025. The model was then used to run five scenarios: a base case reflecting confirmed operational capacity; a high-VRE case based on national expansion plans; a medium-VRE sensitivity scenario at the midpoint of the two main cases; a geothermal must-run scenario testing dispatch priority for geothermal plants; and an optimal VRE capacity scenario identifying the penetration level at which the annual mean price crosses zero. The process by which the model clears supply and demand to arrive at the settlement price and quantity is illustrated in **Figure 1-4**. The benefit the market gains from the clearing is termed social welfare. It is a combination of consumer and producer welfare. The model was validated against Kenyan 2023 grid statistics published by EPRA. The validation achieved a deviation of 0.58% in total dispatched energy.

Figure 1-4

An electricity supply and demand curve showing social welfare



The qualitative phase used semi-structured interviews with eleven key informants drawn from regulators, utilities, generators, and the EAPP Secretariat. Informants were presented with the simulation results and invited to assess the model assumptions, and findings, and their implications for EAPP market. Thematic coding produced eight themes that served to validate and contextualise the quantitative findings. Together, the quantitative and qualitative phases constituted an explanatory sequential mixed-methods design.

1.4.2 Significance of the Study

This research is significant at an empirical, theoretical, methodological, and practical level. Empirically, it provides the first agent-based simulation of a day-ahead wholesale electricity market for the EAPP. Quantitative findings on pricing dynamics, dispatch outcomes, CO₂ emissions, and battery storage economics are derived. The results provide a quantitative basis for EAPP market design decisions. The research comes at a time when the EAPP day-ahead market is about to be launched. The findings can inform the design choices that will shape the pool's operation for decades.

Theoretically, the research develops the renewable-versus-renewable framing in the market access tension between zero-marginal-cost wind and solar, and firm renewable geothermal. This framing extends VRE integration theory to the specific conditions of Eastern Africa. It also has implications for other regions where firm and variable renewables compete in emerging wholesale markets. The simulation evidence contributes to the policy debate between on regional integration and bilateral arrangements (Elabbas, 2023a; Hancock, 2024).

Methodologically, the optimal-VRE capacity scenario introduces a replicable approach for identifying the market absorption capacity of an electricity system. It computes the level of additional VRE beyond which the annual mean price turns negative. This level is essential for the provision of investment signals. The gap between national generation expansion planning targets and realistically achievable deployment levels is noted to be significant. Simulation approaches require to develop methods of moderation. This method is applicable to other power pool contexts where the gap between planned and market-absorbable VRE capacity is of relevance.

Practically, the research will advance the activities of the EAPP by providing quantitative evidence on market pricing and dispatch outcomes. Policy challenges that will affect the EAPP market in a high-VRE environment are highlighted. These include negative pricing, geothermal curtailment, and the governance requirements of real-time market operations. The research provides a basis for market participants to pre-empt solutions to these challenges thereby enabling utilisation of more RE. The AMIRIS platform adapted for this research, provides a reusable modelling foundation that can be customised for similar studies in other African power pools. This extends the methodological impact beyond the EAPP.

Broadly, the research demonstrates that the EAPP's renewable energy resources can be harnessed through a regional short-term market. Such a market would provide additional avenues for trade extending the current bilateral trade. The EAPP countries continue to experience economic and population growth that will mean more demand for electricity (AfDB, 2025). The abundant renewable energy resources can be utilised to support this growth. The ability to trade electricity regionally in short-term markets this utilisation in an efficient manner. Cheaper, and cleaner electricity will expand across the pool due to lower marginal pricing in the pool (Bird et al., 2013; Brijs et al., 2017).

Trading at pool level will also allow economies of scale in building generation projects. The additional external market will be a boon for developers looking for alternative offtake opportunities. This will also reduce the demand for state guarantees, that EAPP governments are less willing to give in recent times. The option of trading into the EAPP pool will improve project economics and diversify investment options.

This research is also significant in the context of the United Nations Sustainable Development Goal (SDG) 7, which calls for universal access to affordable, reliable,

sustainable, and modern energy by 2030. Eight of the thirteen EAPP member countries have electricity access rates between 40% and 60%, and two have rates below 10% (World Bank et al., 2023). The high cost of electricity generation remains a structural barrier to energy access at the household and productive use levels. The literature identifies competitive wholesale markets as a mechanism for reducing the cost of electricity supply (Rudnick & Velasquez, 2018). Cost reductions would directly support the affordability and access dimensions of SDG7. The connection between the research findings and SDG7 is empirically grounded in the simulation results.

CHAPTER 1.5: RESEARCH QUESTIONS

Research questions were developed to explore the complexities of competitive wholesale electricity markets. The use of research questions allowed the researcher to explore the field of electricity markets and glean knowledge relevant to refining the investigation (Barroga & Matanguihan, 2022; Purvis et al., 2024). The research was structured around three questions, each addressed through a specific methodological approach:

RQ1 How is electricity traded globally and in Eastern Africa?

This question was addressed through the literature review (Chapter 2) and key informant interviews (Chapter 4). This question establishes the theoretical and institutional context, characterising the current EAPP market structure and the gaps that short-term trading would address.

RQ2 How would a wholesale electricity market in Eastern Africa be affected by introduction of more varying renewable energy?

This was addressed through agent-based simulations (Chapters 3 and 4). This question generated the quantitative evidence on pricing, dispatch, supply security, emissions, and battery storage economics. It thus represents the primary empirical contribution of the research.

RQ3 How accurate is the simulation of short-term trading in the EAPP?

This was addressed through the key informant interviews and the Kenyan grid validation (Chapters 3 and 4). This question validated the model, identified the misalignments between simulation and operational reality, and provided the qualitative contextualisation that the simulation could not offer.

CHAPTER 1.6: STRUCTURE OF THE THESIS

The thesis is organised into five chapters. Chapter 2 reviews the literature on electricity market evolution, economic theory, short-term market design, VRE integration, developing country market approaches, the political economy of the EAPP, and links the literature to research variables selection. Chapter 3 describes the research methodology, including the AMIRIS model and its adaptation, and the quantitative phase with simulation scenarios, and the mixed-methods design.

Chapter 4 presents the quantitative simulation results and qualitative findings, including misalignments between the quantitative and qualitative findings. Chapter 5 presents the implications, policy recommendations, future research agenda, and conclusions. The references and appendices are given in Chapter 6 and Chapter 7, respectively.

The five chapters provide the first comprehensive quantitative and qualitative analysis of a day-ahead wholesale electricity market for the Eastern Africa Power Pool, a contribution timed to inform the most significant energy market transitions in Eastern Africa's history.

CHAPTER 2 LITERATURE REVIEW

CHAPTER 2.1. INTRODUCTION

This chapter reviews the literature underpinning the three research questions of this study: how electricity is traded globally and in Eastern Africa; how a wholesale electricity market in Eastern Africa would be affected by more variable renewable energy; and how accurate an agent-based model of the EAPP wholesale market can be. The chapter moves from foundational economic theory through applied market design, VRE integration, and the political economy of regional power pools, building toward variable definitions and the research design described in Chapter 3.

This study combines three bodies of literature: electricity market design theory, VRE integration theory, and political economy in regional electricity markets theory. Electricity market design theory is the conceptual basis for competitive short-term markets and the design challenges that high VRE penetration introduces. These topics include the merit order effect, negative pricing, and the missing money problem (Kirschen & Strbac, 2018; Rudnick & Velasquez, 2018; Stoft, 2015).

The political economy of regional energy integration frames the institutional and governance issues in the EAPP short-term market development. This describes the tension between national sovereignty and regional efficiency, which influences the speed of EAPP development (Barnett, 2014; Elabbas, 2023a; Elabbas et al., 2023; Oseni & Pollitt, 2014, 2016).

VRE integration theory describes the effects of increasing levels of grid-based VRE (wind and solar) on pricing, dispatch, and investment. It describes negative pricing outcomes and the role of contracts for difference in sustaining investments at high-penetration levels

(Ason & Dal Poz, 2024; Holttinen et al., 2021; Reichenberg et al., 2023). The independent variable in the research, VRE penetration, and the three dependent variables (electricity pricing, dispatch of power plants, and stability of supply) are grounded in theory, as described in Section 2.9.

The remainder of this thesis is organised as follows. Section 2.2 presents the theoretical and conceptual framework, placing the research within microeconomic theory and describing the variable relationships that structure the simulation. Section 2.3 reviews the evolution of electricity markets with specific reference to the five EAPP countries. Section 2.4 covers the economic theories governing electricity markets and concludes with a bridge to the three applied theoretical bodies. Section 2.5 reviews short-term market design elements relevant to the EAPP context. Section 2.6 reviews VRE integration, including a new section on the specific challenge of geothermal dispatch in merit-order markets. Section 2.7 covers developing country market approaches, prerequisites for wholesale markets, and the EAPP and SAPP specifically. Section 2.8 reviews the political economy of the EAPP, critically evaluating the literature and linking it to the modelling assumptions of the research. Section 2.9 explicitly links the literature to the research variable selection. Section 2.10 summarises the key learnings of the chapter and their implications for the research design.

The three theoretical approaches interlink to enable a wholesome understanding of the EAPP short-term market under high levels of VRE. Electricity market design theory provides the background theoretical grounding of markets, whereas VRE integration theory introduces the nuances related to these generation technologies. The political economy theory grounds the research in the Eastern African context.

The literature review utilised databases such as Elsevier, Google Scholar, ProQuest, ResearchGate, Wiley Online Library, ScienceDirect, and IEEE Xplore. The primary focus was on peer-reviewed publications from 2019 to 2025, supplemented by foundational works outside this range. The key search terms were wholesale electricity markets, short-term electricity markets, variable renewable energy integration, negative pricing, Eastern Africa Power Pool, power pool political economy, contracts for difference, and agent-based modelling of electricity markets.

CHAPTER 2.2: THEORETICAL AND CONCEPTUAL FRAMEWORK

2.2.1. Theoretical Framework

An analysis of electricity markets necessitates the application of economic theory to describe market operations. Specifically, microeconomic theories were applied in this study, including the theory of consumer behaviour, the theory of a firm, market theory (oligopolistic market theory), game theory, and auction theory (Kirschen & Strbac, 2018; J. Lin & Magnago, 2017; Stoft, 2015). These theories and their relevance to this study are further expounded in the next paragraphs.

The electricity market, at its most basic, involves the trade of a commodity between producers and consumers. Thus, understanding consumer behaviour is essential. Consumer behaviour theory characterizes the decision-making process of a consumer with limited resources who is looking to purchase goods and services. The utility function, which describes the satisfaction level of the consumer with the product, is the most important concept of this theory (Kirschen & Strbac, 2018). The additional benefit of consuming one extra unit of the product, marginal utility, is an important consideration for rational consumers. Other important concepts of the theory are the contextualisation of the individual and market demand, and consumer surplus (J. Lin & Magnago, 2017). In the electricity market this theory has been applied to the trade of electricity as a commodity between producers and consumers. Some controversy exists on whether this theory should be an independent discipline, definition of what should be included as consumer behaviour and whether consumer behaviour is interdisciplinary (Macinnis & Folkes, 2010).

In the EAPP context, demand is highly price-inelastic in the short term because electricity trade occurs through bilateral contracts with fixed tariffs, rather than real-time

pricing. These have fixed tariffs rather than real-time pricing. This inelasticity implies that wholesale market price signals do not immediately translate into demand responses. Consequently, the efficiency benefit of the market is concentrated on the supply side. This constraint is modelled in this study by fixing the demand in the simulation model.

Electricity producers are often organisations, and their decision-making dynamics differ from those of individuals. The theory of a firm or industrial organisation describes how decisions are made in companies. The fundamental concept in this theory is the assumption that companies will always act to maximise their profits (Toms & Wilson, 2014). A company will produce at a level that ensures the maximum positive value between revenues and production costs. There has been some controversy regarding whether it is the utility to the firm that should be maximised and not profits (Papandreou, 1952). Another important concept in this theory is producer surplus, the difference between the marginal cost of production and the market price.

The concept of social welfare combines consumers' and producers' surpluses to define the gain or loss to market participants, and its maximisation defines market efficiency, a key objective in competitive markets. In the EAPP, the dominant firms are state-owned utilities, whose objective functions may diverge from pure profit maximisation toward energy security, employment, and political objectives. This divergence between theoretical profit-maximisation and actual bidding behaviour provides a reason to examine the strategic behaviour of agents in a market. Agent-based modelling can parameterise diverse agent decision rules and is preferred over equilibrium approaches for this study.

The environment in which electricity trade occurs also affects the effectiveness of the trade. The theory of markets describes the different market structures and market power of the participants. This theory describes the types of market structures as perfect competition, pure

monopoly, monopolistic competition, oligopoly, and monopsony. The difference in these is the number of participants on either the buying or selling side and their respective market power that defines how capable they are of controlling the price according to their interests (Kirschen & Strbac, 2018). The Oligopolistic market is most typical of electricity markets. In this structure, a few companies compete against each other, and high barriers to entry limit new entrants. Interactions with other market participants can bias market outcomes. Oligopolistic markets are defined using four models: Collusion, Bertrand model, Stackelberg model and the Cournot model. The other interesting concept in general markets is market failure. This is when a market is unable to produce efficient outcomes, leading to non-optimal price and supply.

Electricity markets have seen an increasing interest in parties arriving at efficiency, which has led to the introduction of auctions for both demand and supply. The theory of auctions describes the types of auctions, possible regulations, and outcomes of the auction frameworks. In auctions, electricity is traded in a bidding process with competition among players to secure a commodity on offer. Auctions can have different formats, including bidding methods such as the traditional English auction, Dutch auction, and sealed-bid auction, or payment methods, such as pay-as-bid, uniform-pricing, and multiunit Vickrey auctions (Becker, 2001; Kirschen & Strbac, 2018; Stoft, 2015).

The presence of multiple participants and the possible effects of influencing market outcomes due to strategic interactions with the market and other participants makes electricity trade similar to a game. Game theory studies the interactions between market participants and how these affect participant returns. An important concept in game theory is the definition of the type of game, that is, whether it is cooperative or non-cooperative. In the former, companies agree on contracts that allow them to work together strategically for mutual benefit. In non-

cooperative games, such companies aim to outdo each other, as typified by auctions and electricity markets.

The non-cooperative game is the most analytically relevant framework for this study. Generators simultaneously submit sealed bids without knowledge of competitors' strategies (Fabra et al., 2006). In theory, Bertrand competition among generators should drive bids to marginal cost, achieving a competitive equilibrium.

In practice, generators in concentrated markets learn their competitors' cost structures over repeated auctions. They then develop tacit coordination strategies that sustain prices above competitive levels. This is likely in the EAPP given its small number of state-owned participants and the absence of established market monitoring (J. Lin & Magnago, 2017). With five country-level participants in the simulated market in this research, there is great potential for coordination in bidding strategies.

Game theory also informs auction design, the format of the EAPP's proposed day-ahead market. This determines the equilibrium bidding strategy and the degree to which market power can be exercised (Klemperer, 2002). Regulatory monitoring for the structural exercise of market power should therefore be an early priority for the EAPP market operator, particularly given Ethiopia's dominant capacity (Twomey et al., 2005).

The analysis and design of electricity markets require that markets be modelled using mathematical formulations to allow for programming and simulations. Electricity markets are commonly described by linear functions with various conditions or constraints representing the physical and nonphysical limitations of electric networks. Sets of linear inequalities are developed to model electricity markets and subsequently solved through programming to determine the most optimal levels of pricing and volumes of electricity in each trading framework. Concepts related to auction theory, game theory, and other microeconomic theories

are incorporated. These inequalities are used to model power system problems, such as unit commitment, economic dispatch, and optimal power flow (Kirschen & Strbac, 2018). Stochastic optimisation applied under this theory will also allow the modelling of variable renewable energy.

The theoretical framework described above brings together the necessary concepts to understand and model short-term electricity trading. The theories of the consumer and the firm provide a basis to understand the motivations and goals of interactions between electricity consumers and producers. Auction theory and the theory of markets form the basis of electricity trade globally and in Eastern Africa, providing the theoretical backing for Research Question 1. Optimisation theory will form the theoretical basis of the investigation under Research Question 2, as the electricity market is modelled as a linear optimisation problem to enable analysis and design directed by game theory. However, optimisation theory is not covered in this review as it applies to modelling that will be covered in later chapters.

2.2.2. Conceptual Framework

Conceptual frameworks describe a researcher's understanding of research variables and factors (Luft et al., 2022). They describe the presumed relationships between different concepts in the research. These frameworks combine established theory and the researcher's emergent ideas. These ideas allow a connection to be drawn with the purpose of the study. The conceptual framework describes how a researcher organises a study, from the introduction to the approach and conclusions. This makes the case for the significance of the study and how the design appropriately answers the research questions (Farrow et al., 2021; Jozkowski, 2017).

This study investigates the effect of introducing short-term electricity trading to encourage the development of renewable energy in Eastern African electricity markets. This study aims to contribute to addressing the harnessing of the potential of renewable energy in Eastern African power plants to provide more electricity for economic development in the region. Short-term markets and VREs are also seen as ways to improve reliability, increase trade among countries, and control the cost of electricity.

The conceptual framework of the research is shown in **Figure 2-1**. To undertake the study, a definition of the variables was necessary. The dependent and independent variables relevant to the research and research questions were identified. The moderating, control, and mediating variables were also defined. The relationships between these variables are summarised in **Figure 2-1** and operationally defined in Chapter 3.5.

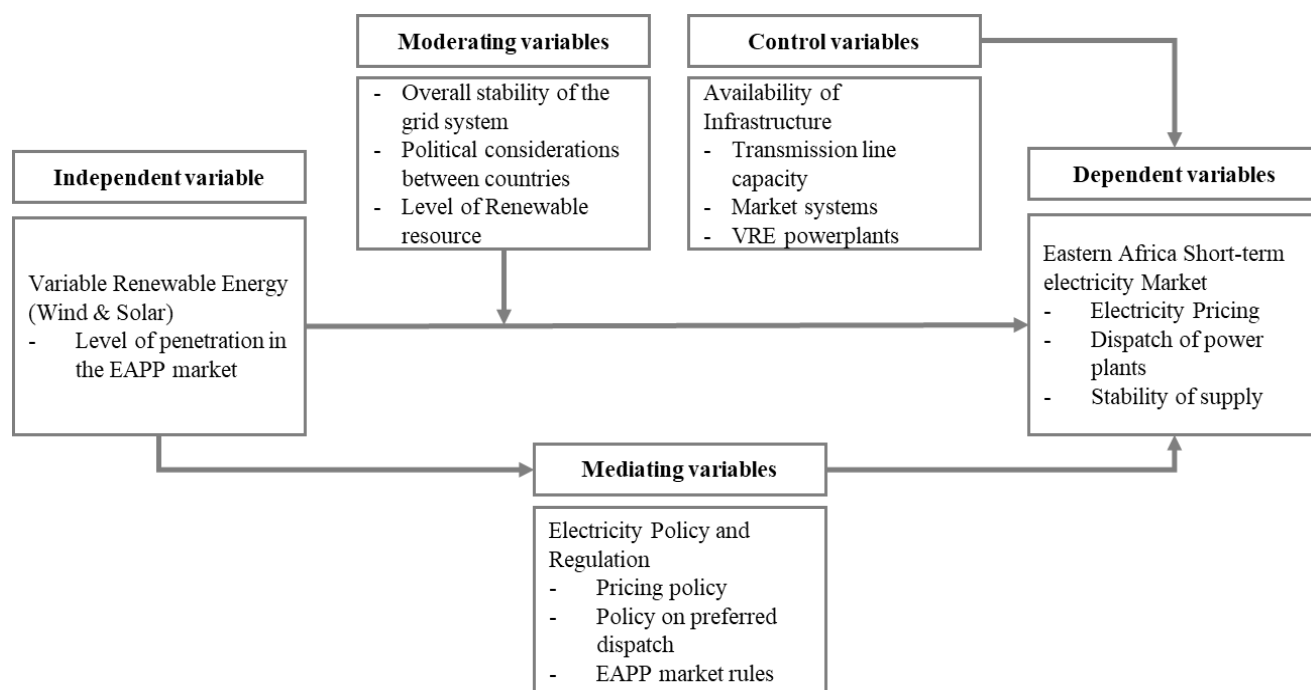
In this study, the independent variable is the level of VRE penetration in the EAPP, and the dependent variables are electricity pricing, the level of dispatch of power plants, and the stability of supply in the EAPP. The independent variable is connected to the three dependent variables through three pathways. The pricing pathway runs through market clearing. As VRE

penetration increases, zero-marginal-cost wind and solar displace higher-cost technologies in the dispatch. This drives down the average clearing price and increases the frequency of negative prices.

These interactions are however within a given political and regulatory framework. A well-designed framework will eliminate the inefficiencies of bilateral markets and shortcomings of individual country markets. In a pool setting with multiple governments with different policies on electricity the balance of these interests will affect all aspects of the market. Perceptions of dominance by one country will affect the trust levels from other countries that could stall progress on standardisation of procedures. This has been observed in the EAPP(Elabbas, 2023a).

Figure 2-1

Conceptual Framework of the research



The dispatch pathway considers power plant utilisation. VREs receive a larger share of the awarded energy, and conventional plants and firm renewables, such as geothermal, are likely to be curtailed. This reduced usage negatively affects asset utilisation and reduces the attractiveness of investments for necessary conventional generation. The supply stability pathway considers the ability to supply. A high VRE capacity reduces peak supply shortfalls by providing more generation options. However, the variable nature of VREs implies that the security of supply depends on the available transfer capacity in the transmission system. The moderating, control, and mediating variables that affect the interactions of the dependent and independent variables are described.

The research undertakes a review of the literature to identify theoretical approaches and documented experiences related to the research topic. This includes economic theories governing short-term electricity markets, experiences in short-term electricity markets with increasing levels of penetration of VREs, and approaches taken in developing country markets. The review is grounded in the extant literature by theoretically framing the research process.

The research questions were developed considering the topic, problem statement, and variables in the research. The research approach was chosen to enable a comprehensive response to the research questions. Given the need to highlight both the quantitative and qualitative aspects of VRE penetration on the grid, a mixed methods approach was chosen for the study. This began with a quantitative analysis undertaken using a simulation research design. A model of the EAPP short-term market was developed, and simulations were run to understand the effects of variations in the independent variable on the dependent variables. Simulations were necessary as the EAPP short-term market is not in place, and the research could not be undertaken on a live market.

The research further moves into a qualitative step to reveal deeper insights into the relationships between the variables and the research settings. Qualitative research verifies the quantitative findings, assumptions, moderating, control, and mediating variables against the knowledge of key informants in the region's electricity market. Key informants also bring out different concepts and themes that the researcher may have missed or that require more emphasis in the research. Views were gathered using semi-structured interviews.

The findings from the quantitative and qualitative processes are reviewed in terms of their responses to the research questions. Recommendations for industry and future research are then developed. The research concludes with conclusions describing the relationship between the dependent and independent variables.

The researcher's role in the research was to moderate the research process, run simulations, and undertake interviews in a non-biased manner. The researcher is a practitioner in the electricity market in the EAPP in the field of private power generation. It is necessary to be aware of any biases and opinions on VREs, the EAPP, and short-term markets and to ensure that they do not affect the research process and findings. The researcher also brings emerging concepts in the field of study to the research to improve the quality and relevance of the research in its setting in the EAPP.

CHAPTER 2.3: EVOLUTION OF ELECTRICITY MARKETS

Electricity markets have evolved in terms of how the commodity is traded and its definition. This section reviews the literature on how markets have evolved.

2.3.1. Organisation structure of electricity markets

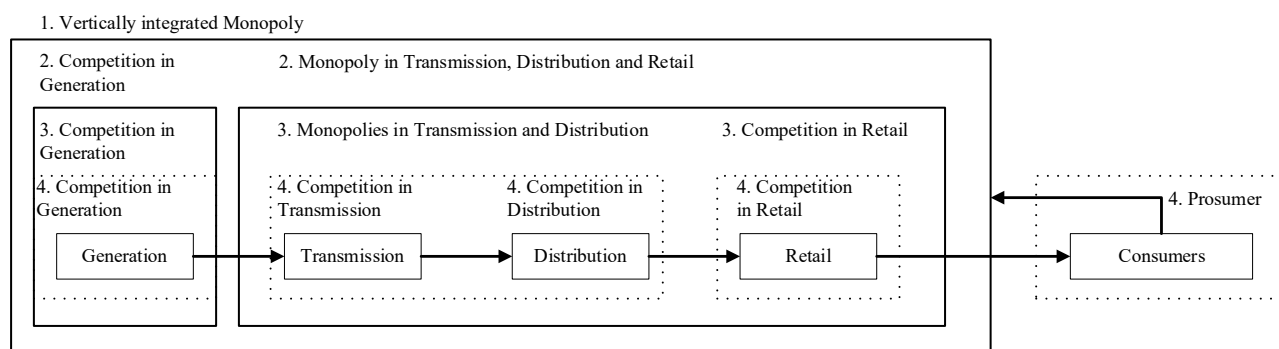
Electricity supply has been considered a natural monopoly for most of the 20th century, with vertically integrated utilities generating, transmitting, distributing, and retailing electricity to consumers (Hobbs & Oren, 2019; Kirschen & Strbac, 2018; Ranci et al., 2013; Stoft, 2015). These monopolies also have a monopoly on such supplies over the geographical spread of a country or region. These monopolies have progressively eroded in most markets. The introduction of varying degrees of unbundling and deregulation began in the early 1900s (Kapika & Eberhard, 2013; Kessides, 2012; Kirschen & Strbac, 2018; Rudnick & Velasquez, 2018). This change was motivated by a wave of liberalisation across various sectors, insufficient public funds for fund generation, and widespread withholding of multilateral funding for state projects. Technological advancements in information technology and generation plants, especially gas turbines, have also played a role. Consumer dissatisfaction due to poor service delivery and incurred costs resulting from unnecessary expenditures on new plants by monopolies have also put pressure to end monopolies (A. Eberhard et al., 2018; Meyer et al., 2018; Ranci et al., 2013). The transition to a more liberalised market was hoped to improve the quality of service and reduce prices by invoking market discipline to replace monopoly regulation and government policy (Kirschen & Strbac, 2018). In Kenya, the transition was motivated by the need to access international funding after five years of a funding freeze and by technocrats looking to embed reform in the sector (Godinho & Eberhard, 2019).

In the most advanced unbundled electricity market model, there is competition in generation, wholesale transmission, distribution, and retail. Multiple players may be present at more than one level and may or may not be state-owned.

The stages of unbundling an electricity market are shown in **Figure 2-2**. These stages are not necessarily followed stepwise but are common practice when monopolies are broken following the ‘standard model’ (Arowolo & Perez, 2020; Gore et al., 2019; Kapika & Eberhard, 2013; Kessides, 2012; Sioshansi et al., 2006). This standard approach includes corporatisation, commercialisation, passage of requisite legislation, establishment of an independent regulator, establishment of independent power producers, unbundling, divestment from generation and distribution, and introduction of competition (Dertinger & Hirth, 2020; A. Eberhard et al., 2018).

Figure 2-2

Stages of electricity market unbundling



Note. Developed from (Kapika & Eberhard, 2013), (Ritzer et al., 2016) and (Godinho & Eberhard, 2019)

First, the market is dominated by a vertically integrated monopoly that has been carved out into a separate legal entity by the government. Commercialisation is undertaken to ensure that electricity prices reflect the cost of electricity. Legislation is passed that allows private and foreign entities to participate in the sector. An independent regulatory body is

established to manage the sector fairly. In preparation for privatisation, the state-owned utility is separated into a generation and a transmission and distribution entity. Second, competition is introduced in the generation of independent power producers supported by long-term power purchase contracts. Third, competition is introduced in retail, as transmission and distribution remain monopolies owing to steep entry barriers and localisation. Fourth, competition is introduced in transmission and distribution, and wholesale and retail markets are created (A. Eberhard et al., 2018). Consumers also innovate by producing and feeding electricity back into the grid.

In African markets, reforms have progressed only partially, leading to the development of hybrid power markets (Kapika & Eberhard, 2013). In these markets, the independent regulator grapples with regulating dominant state-owned utilities that compete with independent power producers and must adapt regulatory tools meant to promote private utilities. There is a view that an incomplete reform process results in little to no competition among independent power producers. This has exposed countries to exchange rate risks owing to long-term power purchase agreements, related government guarantees, and security requirements (A. Eberhard et al., 2018).

The trajectory of African market reform warrants critical engagement beyond observation. The markets that have emerged in sub-Saharan Africa are not a failed version of the 'standard model' but a structurally distinct hybrid market form (Gratwick & Eberhard, 2008). This is characterised by partial unbundling, dominant state-owned single buyers, and a growing IPP sector financed through long-term bilateral contracts. This structure responds to different political and financial conditions from those that drove European liberalisation.

This hybrid market is not a transitional stage but may represent the long-run institutional equilibrium in the region. It is driven by financing constraints on state utilities,

political incentives for governments to retain control over strategic infrastructure, and the absence of sufficiently deep domestic capital markets. The implications for the EAPP are significant. If the bilateral PPA regime is a persistent structural feature, the design of the EAPP day-ahead market must accommodate coexistence with long-term bilateral contracts and not assume their progressive displacement (A. A. Eberhard et al., 2016; Gratwick & Eberhard, 2008).

Markets in various countries display variations in structure, as shown in **Figure 2-2**, with different degrees of unbundling (Kapika & Eberhard, 2013). African markets vary in the degree of unbundling, with Kenya and Uganda having unbundled and increased competition in generation and distribution, with Uganda having gone further. Tanzania and Senegal have liberalised only their generation subsectors. This follows a trend toward retaining control of the perceived monopoly side of the business (Godinho & Eberhard, 2019). This resistance to change also corresponds to authoritarianism in a country and the need to exercise sovereignty over decisions concerning its institutions (Urpelainen & Yang, 2019). This is symptomatic of the desire to push back on donor-led template programs to access funding. This is particularly evident in countries with historically grounded ideologies, such as Tanzania's '*ujamaa*' (Gore et al., 2019).

Further afield, some markets, such as PJM in the US, are sophisticated, with retailers, demand aggregators, and multiple financial instruments, whereas others, such as Brazil, have long-term supply auctions (Rudnick & Velasquez, 2018). South Africa was the first country in Africa to move toward market liberalisation, largely as a consequence of a crisis in electricity supply. Liberalisation has led to the opening of self-supply, wheeling, and the establishment of a wholesale market, complete with traders (Frack & Serrano, 2025; NECOM, 2024).

Researchers contend that it is difficult to prove that fully unbundled markets operate more efficiently than centralised markets (Dertinger & Hirth, 2020; Kirschen & Strbac, 2018). They cite the balance between the loss of coordination between the generating plant and transmission system in a monopoly. This is compared to the gain in the availability of plants in a competitive market. The desire for profit is a motivator for maintaining plants in good condition. They question the value of the gain in availability versus the loss of the ability to coordinate vertically. The influence of politics in planning may also persist, and an example of the Kenyan regulator and utilities is provided. The country has seen positive influences, as in the case of political commitment, leading to an increase in access to electricity in Kenya from 18% to 75%. Negative influences, such as a 30% oversupply of generation capacity in Kenya, were also observed (Godinho & Eberhard, 2019). However, reforms have been associated with increased electricity access (Dertinger & Hirth, 2020).

Although planning for demand in a monopoly has been blamed for being imprecise, leading to excess generating capacity that the consumer must pay, there is no guarantee that decisions made by profit-seeking generators to build new plants will result in more efficient supply tracking demand. This is despite the fact that the cost of overcapacity is borne by the generator and not by the consumer (Kirschen & Strbac, 2018). The unbundling of Nigeria's electricity market between 2010 and 2013 was unsuccessful in delivering better services because of economic, institutional, technical, financial, and sociopolitical challenges (Arowolo & Perez, 2020; Babatunde et al., 2023). However, market reforms in Uganda have been successful in increasing supply availability and attracting investment. The same availability has also been achieved in Ethiopia without significant reforms. Incomplete reforms have also been found to limit the effective integration of VREs (Iychettira, 2021).

2.3.2. Electricity as a Commodity and its Trade

Electricity is unique as a commodity in four ways (Ranci et al., 2013). First, electricity cannot be stored economically and is typically consumed simultaneously as it is generated. Second, the demand for electricity varies within a day and with the weather. Third, a large portion of electricity demand is price-inflexible in the short term; thus, demand cannot immediately react to a change in supply, as is the case for standard commodities. Finally, electricity is delivered through interconnected transmission lines, the capacity availability of which may affect the ability to alter supply or demand, especially where congestion occurs. These peculiarities imply special consideration for trading electricity as an economic commodity.

Electricity delivered to consumers is a bundle of services that includes generation, transmission, distribution, frequency control, and voltage support (Stoft, 2015). Each of these services has a demand and supply side and requires separate submarkets for trade. These services can be provided in the free market, by state agencies, by regulated suppliers, or by a combination of these. Each relevant submarket must be considered when evaluating wholesale electricity markets (Rudnick & Velasquez, 2018). This includes how they interact with each other and how the general sector is organised.

There are two ways to organise trade between buyers and sellers (Stoft, 2015). Trade can be direct, where a seller sells directly to a buyer in a ‘bilateral trade, or it can involve an intermediary who buys from the seller and sells to the buyer in a ‘mediated trade’. He adds that entire markets normally use a mixture of these types to cover all scenarios. Bilateral markets can be complemented by balancing markets, such as those in the European Union and the United Kingdom (Rudnick & Velasquez, 2018). Markets can also be bid-based and

driven by market clearing, such as in New Zealand, Australia, Ontario, Ireland, and Singapore. South America and Korea have, however, implemented cost-based power pools.

2.3.3. Power Market Structures

Electricity markets comprise all commercial transactions involving electrical energy and other complementary reliability products that support electricity supply (Perez-Arriaga et al., 2017). These complementary products include ancillary services and reliability products, which ensure that the supplied electricity is sufficiently secure and of adequate quality.

The wholesale electricity market structure at its most advanced stage comprises generating companies, distribution companies, retailers, a market operator, an independent system operator, transmission companies, a regulator, and small and large consumers, as shown in **Figure 2-3** (Kirschen & Strbac, 2018). Large consumers participate directly by purchasing electricity from the market and may also provide load control as a service. Small consumers lease connections to the grid and purchase power from the retailers. The regulator is a state agency that ensures fair and efficient operation of the sector.

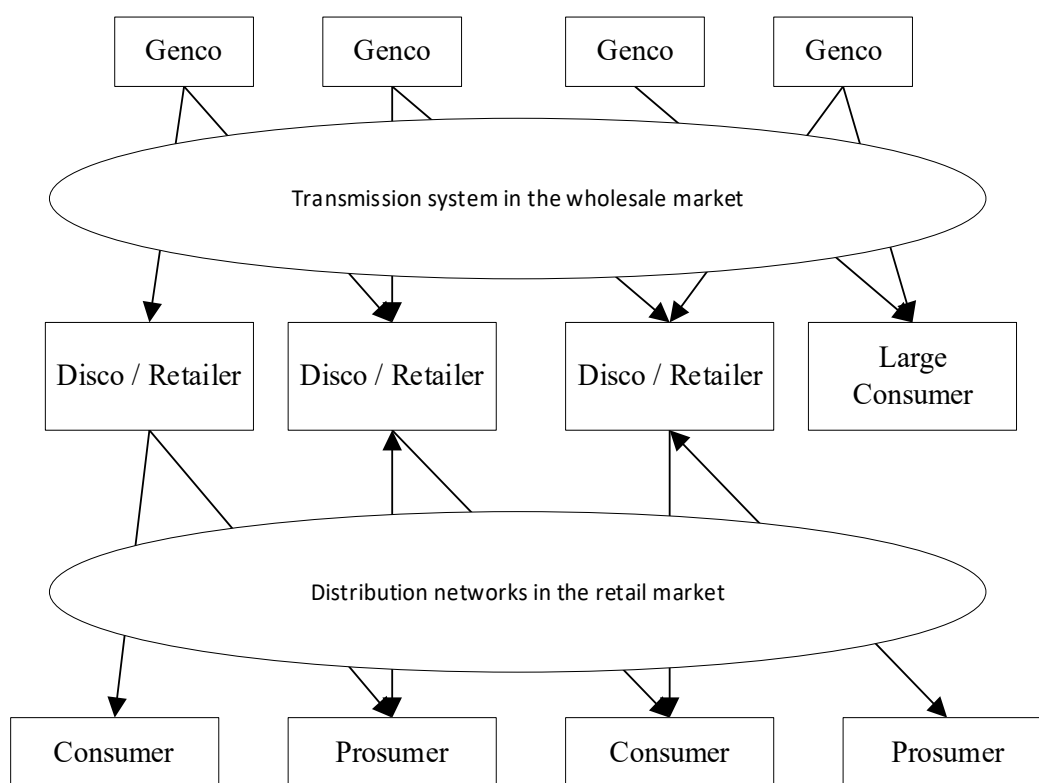
Transmission companies own interconnection facilities, including transmission lines, substations, and reactive power compensation devices. They operate the system according to the instructions of an independent system operator (ISO). The ISO primarily maintains grid quality and security. The market operator runs a market that matches bids and offers for supply and consumption. This structure may vary; for example, in the US, the ISO also performs market operations.

Generating companies produce and sell electric energy and may also sell regulation, voltage control, and reserve capacity. Distribution companies own, develop, and operate

distribution networks. Finally, retailers buy electricity from the wholesale market and sell it to consumers. Retailers can be subsidiaries of local distribution companies (Kirschen & Strbac, 2018). The electricity market has also witnessed the advent of consumers, with installed generation units selling power back to the grid at the distribution level (Perez-Arriaga et al., 2017).

Figure 2-3

Participants in the wholesale market were interviewed.



Note. Developed from (Kirschen & Strbac, 2018) and (Rudnick & Velasquez, 2018)

2.3.4. Single Buyer Model

Electricity markets worldwide are currently still dominated by single buyer models. The transition away from vertically integrated utilities to a single-buyer model was driven by

the need to improve utility performance and accommodate large demand growth in the country. Utilities have insufficient revenue to cover capital, operational, and maintenance costs. They have experienced high losses, below-production-cost tariff regimes, and low levels of revenue collection. Demand has been growing faster than the available public sector funds to build power plants. This necessitates opening the generation sector to private investments.

Single-buyer models have one, often state-run, utility licenced as the only buyer of electricity from private and public generators. This is a step away from vertically integrated utilities. These single buyers may vary, with some retaining ownership of the generation assets and others only performing the buying role and not owning the generation assets (Akcura & Mutambatsere, 2024). This model is easy to implement and offers flexible approaches to organising the power sector or mid-way before wholesale markets. The shift toward wholesale markets has been driven by the need to achieve better efficiency in terms of affordability, quality of supply, sustainability, and electricity access. The development of such a model has resulted in such efficiencies in Vietnam (Lee & Gerner, 2020).

The single-buyer model has also been viewed as a means of encouraging small private producers and prosumers to participate in the market. However, this comes with the discretionary power of the single buyer to decide from whom to buy power (Eiamchamroonlarp, 2021). It has been argued that gradual reforms and the transition to wholesale markets allow the learning of the best sector structure and enable a more effective wholesale market (Lee & Gerner, 2020). In the next section, the research reviews the literature on wholesale markets.

2.3.5. Wholesale Market Designs

Wholesale electricity markets vary from grid to grid and country to country. The design relies on the physical characteristics of each grid. Traditional markets have been defined by centralised power plants supplying electricity (including ancillary services) to a passive demand that was assumed to be inelastic, and dependent on the levels of economic growth and temperature (Perez-Arriaga et al., 2017). This has changed with the advent of distributed energy resources and the increasing penetration of variable renewable energy.

Although electrical energy and related ancillary services are produced simultaneously, they are traded separately. Market participants typically procure energy, whereas system operators procure ancillary services to secure the grid. This trade can occur in different timeframes such as intra-hour (balancing or real-time), intraday, day-ahead, and long-term contracting (Rudnick & Velasquez, 2018). Procurement can be through physical or financial contracts (Perez-Arriaga et al., 2017). These markets are coupled and not easily distinguishable. Reliability products that assure the availability of resources needed for the safe operation of the grid are typically procured long-term, with allowance for adaptation of the buying or selling positions in subsequent shorter-term markets. Capacity mechanisms and renewable energy (RE) support schemes are also considered to be traded in long-term markets.

The reference market in a power system is attributed to the short-term market, which comprises day-ahead and intraday markets (Perez-Arriaga et al., 2017). In these markets, market participants present bids and offers, and an algorithm is used to match and clear them for each settlement period, typically an hour of the next day. Operating reserves are allocated in the day-ahead market, and any variation in real-time availability is handled in the intraday markets. These adjustments to the accepted day-ahead bids and offers are made before market

gate closure. Gate closure is the last moment after which the market agents (offering supply and demand) cannot adjust their offers, and only the system operator can modify the program of demand and supply. A good market design will result in accurate price signals in the short term that allow for efficient use of resources in the market and result in efficient long-term signalling that allows for future investments.

Electricity markets are also concerned with the management of unit commitments and transmission-line congestion. Unit commitment is the service that informs generators when to turn on or off and the quantities to produce. Doubts have been raised regarding the efficiency of these decisions in a liberalised market, in which market participants can make decisions privately (Stoft, 2015). These decisions are also influenced by the start-up costs of generators and the accuracy of prevailing market prices. Another concern is congestion on transmission lines. Congestion management on transmission lines in an electricity grid refers to the management of the rights of access to transmission lines, especially where the available capacity of transfer is less than the volume required to be traded across the line. Appropriate scarcity pricing has been proposed to manage congestion in transmission lines (W. W. Hogan, 2015).

Regarding the type of market, some controversy exists between the proponents of energy-only and energy-plus capacity markets (Rudnick & Velasquez, 2018). The argument centres around how to motivate the construction of new, long-term capacity without revenue guarantees. This is especially prevalent when revenues are dictated by the marginal cost of generation, which may not fully cover the fixed and operating costs of setting up and operating power plants. This scenario is defined as the ‘missing money problem,’ and is a symptom of market failure. This may lead to the early retirement of power plants or a lack of new plants in the long term. To overcome this problem, design approaches with markets that

have both energy and capacity components have been implemented (Ranci et al., 2013). The capacity component guarantees revenues over a longer period, providing investors with long-term confidence to expend high capital costs on power plants. Another school of thought argues for energy-only markets, as in Alberta and Texas, which approximate real-time prices well and incentivise the construction of new generation capacity. This can be achieved in two ways: through scarcity-adjusted energy-only markets by allowing generators to exercise market power to withhold capacity to increase spot prices to eliminate the missing money, or by having higher scarcity prices (W. W. Hogan, 2015).

To adapt to the economic and social changes that will follow, future electricity market designs will need to embrace the principles of open access, technology neutrality, financial rewards for providing system services at the point of need, and recognition of network realities (Hobbs & Oren, 2019). The motivations for establishing a short-term market include non-discriminatory access, completeness of items under trade, reduced trading costs, publicly known prices, and transparent operations (Stoft, 2015).

Electricity market interactions are best described by classical microeconomics, which covers the behaviour of consumers and companies under different market architectures. These theories are further elucidated in the next section on classical macroeconomic theory.

2.3.6. Challenges in Wholesale Markets

The transition to wholesale markets presents its own challenges, including reduced revenues for existing conventional plants, such as coal plants (J. Lin et al., 2019). This is the case in markets with a wider penetration of VREs, which offer lower prices than existing conventional generation assets. This implies less dispatch of these plants, thereby reducing revenue (Atănăsoae et al., 2020; Seel et al., 2021).

Four challenges were identified in the US wholesale markets (Y. Sun et al., 2021). The deployment of VREs leads to a higher need for grid reliability services. The deployment of VREs leads to a higher need for grid reliability services. This would also require the participation of demand-side resources, storage systems, and hybrid systems. This would also require the participation of demand-side resources, storage systems, and hybrid systems.

The second challenge is incentivising the provision of operational-level system resources that allow for operational flexibility and supply grid services. This can be achieved by considering new reserve products, delivery approaches for reserve products, redesigning the ancillary services market, considering appropriate temporal market considerations, and ensuring the sufficiency of frequency response services (Y. Sun et al., 2021). The price formation in markets must be updated to ensure that all delivered services are appropriately compensated. Price formation in markets must be updated to ensure that all delivered services are appropriately compensated. The availability of capacity products should also be considered.

The third challenge identified in wholesale markets is ensuring that the market provides sufficient revenue for the long-term availability of capacity, while also generating price signals for short-term energy and capacity. This is exacerbated by zero-marginal-cost VRE resources that continue to share wholesale markets. Cost recovery for generators will require consideration of scarcity or shortage pricing, together with an understanding of the responsible parties for ensuring that adequate resources are available to meet demand (Joskow, 2019; Y. Sun et al., 2021).

Fourth, better coordination between transmission and distribution is required to allow active participation of consumers in the market. Enabling the visibility of consumers who provide generation or ancillary services by the grid operator is essential. Distribution and

transmission planning should be co-optimised to accommodate the characteristics and capabilities of consumers and the transmission system to ensure supply (Y. Sun et al., 2021).

Market power mitigation is a key challenge in wholesale markets. Research has been conducted to develop tools to detect market power conditions necessary for the optimal operation of wholesale markets (Graf et al., 2021).

The next section elaborates on the economic theories governing electricity markets.

CHAPTER 2.4: ECONOMIC THEORIES GOVERNING ELECTRICITY MARKETS

2.4.1. Introduction

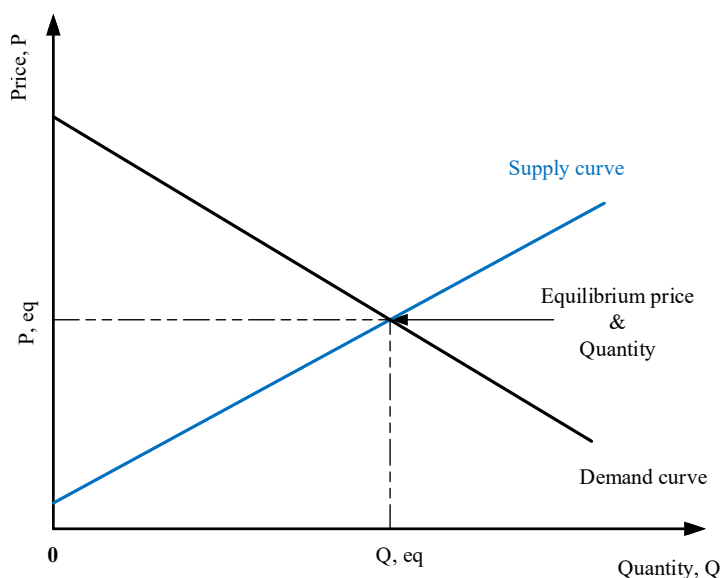
A market comprises buyers and sellers who determine the price for and trade in or exchange a product. In the electricity market, buyers and sellers are consumers and generators, respectively, and the price determined by a neutral third party is known as the market clearing price (Stoft, 2015). The determination of price is an important market objective because the price transmits information about production and consumption, provides incentives, and determines the distribution of income and products. This market-clearing price is determined by the intersection of the demand and supply of electricity (J. Lin & Magnago, 2017).

Electricity markets are defined by both product and geographical range. Segmentation by product includes markets for energy, capacity, voltage support, storage, black-start capacity, reactive power, and ancillary services (regulation, operating reserves, etc.) (J. Lin & Magnago, 2017). Geographical segmentation refers to the physical segregation of the electricity grid into areas of operation that may include entire countries or be split into several zones within a country, such as in Italy and the US.

The relationship between supply and demand is represented by supply and demand curves. Supply curves slope upward and show the relationship between the quantities that suppliers offer for sale and the corresponding prices for each quantity. Demand curves slope downward and show the quantity that consumers are bidding for and the corresponding price they are willing to pay for each quantity. Where these two curves intersect, assuming a competitive market, gives the equilibrium quantity and price (market-clearing price) of the good that is being traded, as depicted in **Figure 2-4**.

Figure 2-4

Demand-Supply curve showing equilibrium price and quantity



Note. Developed from (J. Lin & Magnago, 2017)

Elasticity is an important concept in demand and supply analysis. Elasticity is the ratio of the percentage change in one value to the percentage change in another (Goolsbee et al., 2013). In electricity markets, this relates to the sensitivity of the demand and supply of electricity to changes in another variable, such as price. Sensitivity to price is defined as the price elasticity of demand and the price elasticity of supply. These define the percentage change in the quantity demanded or supplied for every percentage change in price. The price elasticity of demand is typically negative, implying that when the price increases, the quantity demanded decreases (J. Lin & Magnago, 2017). The converse is true for the price elasticity of supply.

Three foundational microeconomic concepts form the basis of analysing electricity markets in this study. Consumer behaviour theory assumes that electricity consumers will

maximise utility subject to budget constraints. The price elasticity of demand for electricity is inelastic in the short term (Goolsbee et al., 2013; J. Lin & Magnago, 2017). The second is firm theory, that assumes generators maximise profit with fixed capital costs and variable fuel costs determining the short-term supply decision (Kirschen & Strbac, 2018). The third concept is social welfare. This is the sum of consumer and producer surpluses and is the standard metric of electricity market efficiency. These concepts are the basis the market power and marginal pricing analysis that follows and inform the interpretation of the simulation findings in Chapter 4.

2.4.2. Market Structures

Market structures can be of different types: perfect competition, pure monopoly, monopolistic competition, monopsony, and oligopoly. Market structures range from perfect competition through monopolistic competition and monopsony to oligopoly. They differ in the number of participants and their capacity to influence prices (Besanko & Braeutigam, 2010; J. Lin & Magnago, 2017). Electricity markets are typically oligopolistic, with few competing generators, high entry barriers, and significant market power potential (Stoft, 2015). In the EAPP context, the dominance of state-owned utilities means the market will initially resemble a monopsony with a single-buyer model and transitioning towards oligopolistic competition as IPPs are admitted and the day-ahead market deepens.

2.4.2.1. Oligopolistic Market Structure

An oligopolistic market is the most common type of market structure. It is characterised by a few competing companies and the limited entry of new companies. Products may be either differentiated or not, and barriers to entry are high. Consequently, some or all companies in the market earn high profits (J. Lin & Magnago, 2017). Strategic

interactions between companies require an understanding of gaming and strategy, as companies act to outsmart competing companies.

Electricity markets are typically oligopolistic, with a few firms competing and high entry barriers (Besanko & Braeutigam, 2010; Goolsbee et al., 2013; J. Lin & Magnago, 2017). Markets tend to have imperfect competition and strategic behaviour embedded in how participants interact. Some examples of oligopolistic markets include the California Independent System Operator (ISO) market in California, the Chilean electricity market, and the Nigerian electricity market (Arowolo & Perez, 2020; Kim & Knittel, 2004; H. Wang et al., 2020).

These interactions among companies in such a market determine the possible market outcomes and the strength of market power (Goolsbee et al., 2013). Firms that interact competitively push prices closer to marginal pricing, resulting in thin margins, whereas firms that interact cooperatively tend to push prices and margins higher. This type of market forces a company to consider the actions of its competitors when deciding how to behave, either by adjusting pricing or production levels at certain times. The likely reactions of competitors are also considered. The fact that other companies also consider the same decisions complicates the strategic decision-making process.

Four models are cited to examine oligopolistic competition: Cournot, Stackelberg, Bertrand, and collusion models. The Cournot model assumes that firms simultaneously set output quantities, achieving equilibrium when no firm benefits from unilaterally deviating. It applies to one-time rather than repeated interactions (Besanko & Braeutigam, 2010; J. Lin & Magnago, 2017). The Stackelberg model allows a dominant firm to set output first. In the EAPP, Ethiopia's dominant generation capacity may enable Stackelberg-type leadership in bidding behaviour that smaller generators must respond to (Besanko & Braeutigam, 2010).

The Bertrand model posits that firms compete on price rather than quantity. This arrangement is unstable because the profit motive incentivises individual deviations from agreed-upon terms. This drives the market toward a Nash equilibrium of zero profit, which mirrors perfect competition (Besanko & Braeutigam, 2010; J. Lin & Magnago, 2017). The collusion model presents the inverse with firms cooperating to form a cartel. They set prices collectively at levels above competitive levels to maximise their profits (Goolsbee et al., 2013). Competition authorities are also actively monitoring for formation of cartels and acting against their market manipulation behaviour.

2.4.3. Market Power

Market power is defined as the ability to alter prices profitably away from competitive levels (Stoft, 2015). It is of interest in electricity markets because electricity is a good used by the entire population, and its price affects the entire economy (Ranci et al., 2013). The uniqueness of electricity as a commodity makes it vulnerable to the exercise of market power (Ranci et al., 2013). Electricity cannot be stored, and its demand is price-inelastic in the short term. When the generation capacity in use is near to being fully utilised, there is an incentive to exercise market power by withholding further production to increase scarcity and, thus, the price. Transmission constraints also isolate different physical locations of the market, reducing competition in each, and increasing the chances of market power being exercised. The use of market power in the electricity market is not restricted to dominant players, as fringe players can also affect marginal pricing by actions such as withholding capacity and causing scarcity (Ranci et al., 2013).

Market power can be exercised vertically (across generation, transmission, distribution, and retail) or horizontally (within a segment) in electricity markets. Market power can also be

exercised locally when transmission capacities are congested and a local producer controls the price (Rudnick & Velasquez, 2018). According to Lin & Magnago (2017) market power is analysed using Joe S. Bain Jr.'s structure, conduct and performance paradigm that postulates that the structure of a market determines the boundaries of an industry which affects performance of companies within the industry. The *structural aspect* determines the market concentration of participants using metrics, including market share, the m-firm concentration index, the Herfindahl–Hirschman index (HHI), and the entropy index. The conduct aspect reviews the behaviour of buyers and sellers with regard to exercising market power internally and with counterparties. The Lerner index is used to assess the potential for exercising market power. The performance aspect includes an analysis of market prices, mark-up by generators, convergence of prices in day-ahead, intraday, and real-time markets, and scarcity state at the time of evaluation (J. Lin & Magnago, 2017). The overall performance of the electricity market can also be measured by assessing the profits of generators, the revenue adequacy of futures markets, and the performance of a capacity market in attracting long-term investments.

The exercise of market power results in the transfer of wealth from consumers to producers and results in deadweight loss to society (a loss due to the price increase, causing more losses to consumers than the way it increases profits to suppliers) (Stoft, 2015). When disputes arise, market power is checked through fines, penalties, and litigation.

To understand strategic interactions in markets, it is necessary to understand auction and game theory. The basic tenets of these theories are described in the following sections:

2.4.4. Auction Theory in Electricity Markets

Electricity trade is today more commonly organised in an auction system, with more countries globally switching to auctions as a means of acquiring new generation capacity

(Azuela et al., 2014; Cunha et al., 2017; Ferroukhi et al., 2015). Auction theory outlines the rules, structures, and outcomes of auctions. A formal bidding process is used in auction markets in which buyers and sellers bid for the product or service under consideration. Three types of auctions have been identified: traditional English, Dutch, and sealed-bid (J. Lin & Magnago, 2017). In a traditional English auction, the price increases, eliminating bidders until only one final bidder remains. The Dutch auction starts at a high price and then reduces value by fixed amounts until one bidder accepts the price. In contrast, sealed-bid auctions have bidders simultaneously submitting their bids, and the most preferred bid is selected from the sealed bids. Sealed-bid auctions can be of two types: first-price and second-price (Vickrey Auction). In the first type, the good is awarded to the highest bidder at her price, whereas in the second-price auction, the highest bidder is awarded at the price of the second-highest bidder.

In an auction, bidders submit bids that are then aggregated by the auctioneer, and the clearing price is determined. Payments follow three mechanisms: pay-as-bid, uniform, and multi-unit Vickrey. In pay-as-bid auctions, the bidder receives the quantity demanded at the clearing price and pays the bid for each unit. Under uniform pricing, the bidder receives the quantity demanded at the clearing price and pays the clearing price for each unit. In multi-unit Vickrey auctions, bidders receive the quantity demanded but pay the opportunity cost relative to the submitted bid (J. Lin & Magnago, 2017). Auctions can be double- or single-sided (Morey, 2001). For electricity, this implies that in double-sided auctions, the auction can be run on the supply side for generators and on the demand side for consumers for a specific period. Single-sided auctions include either demand or supply auctions, but not both for a given period. The revenue equivalence theorem has proven that all four auctions result in the same revenue under the assumption of uniformly known or uniformly unknown

information necessary for formulating bids and offers (Morey, 2001). However, this assertion is limited to one-time auctions and not multiple-round auctions.

In multi-round auctions, the behaviour of market participants is influenced by learning about the bidding process, rules, and other bidders. It is important to design auctions to deter bad behaviour by market participants (Morey, 2001). This is important for electricity markets, as short-term electricity markets have daily auctions that are typical of repeated games. Market participants quickly learn the rules and their beneficial bidding strategies and may apply these to exploit gaps in the rules, limits of the transmission network, and demand and supply elasticities to influence the market-clearing price. Repetition leads to the convergence of market-clearing prices for a given grid and supply conditions. Market participants may develop collective knowledge that may allow them to share the market or fix market-clearing prices owing to their understanding of bidding and operational strategies. For markets with differentiated sub-markets, such as energy and auxiliary services or day-ahead and real-time, the bidding strategies for participants were shaped by their opportunity costs and prices on the auction settlement rules. Bidding strategies are based on whether the two auctions are simultaneous or sequential (Morey, 2001).

The case of suppliers gaming the California Independent System Operator (CAISO) market has been cited by multiple authors (Morey, 2001). The CAISO market had a weak point in the compensation for relieving transmission congestion, owing to the interplay between market design and auctions for acquiring such relief. Suppliers discovered that they could cause artificial congestion in the day-ahead market and get paid for relieving it in the real-time market. They exploited this to increase their profits. The ENRON fiasco and its ‘death star strategy’ is a case study in such exploitation (Oppel, 2002).

Three design principles should be followed in good auctions (Stoft, 2015). The first is to establish the goal of the auction (Morey, 2001). This could be a goal, such as obtaining the least-cost dispatch that allows the balancing of demand and supply while considering transmission system congestion. To achieve this, auction rules must ensure that bidders adhere to their bids and deliver them in real-time. The goal of the auction is emphasised with the example that a one-time auction could be good for meeting an urgent need for capacity, whereas a repeated system auction is good for encouraging investor confidence (Ferroukhi et al., 2015).

The second principle is to provide a complete description (in detail) of the product to be auctioned. A clear definition of the product increases competition and is particularly important for energy and transmission support services (Morey, 2001). The limits of adjusting the product offer in terms of time and quantity should also be clearly defined. This complete description agrees with the concept of ensuring transparency, as encouraged by researchers (Ferroukhi et al., 2015). They argue that the market administrator must define fair and transparent rules and obligations, and that any adjustments to the bid should be communicated to all bidders equally and in a timely manner.

The third principle is to encourage the participation of more players, both large and marginal. This can be achieved by reducing participation costs through modest entry fees and fully refundable deposits (Morey, 2001). Limiting the complexity of the auction, reducing the strategic uncertainty that exposes bidders to large gambles, and eliminating conflicts of interest between participants and market administrators will also encourage bidder participation. However, care should be taken to avoid underbidding, while encouraging serious participants (Ferroukhi et al., 2015). This requires a careful selection of qualification requirements. The auction design should be tailored to the market context.

As noted previously in this section, multiple-round auctions in electricity markets are similar to repeated games. Economic research on games has led to the development and advancement of game theory, which is discussed in the next section.

2.4.5. Game Theory and Electricity Markets

The interactions of market participants in an electricity market can be considered a game. Economists research games primarily using game theory. Game theory is defined as the study of the behaviour of the strategic interactions of economic agents in a complex environment as they make economic decisions (J. Lin & Magnago, 2017). Alternatively, game theory is defined as a branch of microeconomics that is concerned with the analysis of optimal decision-making in competitive situations (Besanko & Braeutigam, 2010). These decisions result in benefits, payoffs, or rewards for the participants. In an electricity market, these decisions can be in an auction setting, where the producer surplus is enjoyed by the auction winner. Game theory can be used not only to develop bidding strategies in an auction but also to design auctions that anticipate gaming by participants. This theory is also used to understand how markets evolve and operate (J. Lin & Magnago, 2017).

Game theory attempts to determine the optimal strategy for each player, assuming that each player will act rationally to maximise their profits. Games can be either cooperative or non-cooperative. In the former case, the players act jointly, whereas in the latter, the players compete without cooperation. Research suggests that, owing to heightened competition in electricity markets, auctions undertaken in these markets are non-cooperative games (J. Lin & Magnago, 2017). In games, when market participants choose strategies randomly, it is termed a mixed strategy; when the choice is only one, it is termed a pure strategy (Stoft, 2015).

Assuming that participants act to maximise their profits, the concept of the Nash equilibrium is interesting. The Nash equilibrium is a concept in game theory that defines the optimal outcome of a game in which no player has an incentive to deviate from their chosen strategy after considering the other players' choices. The Nash equilibrium shows that an equilibrium always exists when there is a finite number of participants and a finite number of pure strategies. The Nash equilibrium is achieved when competing firms in an oligopolistic market take strategic actions while considering the actions of other firms and is used to determine the equilibrium in an oligopolistic market (Lin & Magnago, 2017) (Goolsbee et al., 2013). It is assumed that each player knows their strategies and payoffs, as well as those of other players. It is also assumed that all players are rational and that they will choose actions that maximise their payoffs according to their beliefs, which are modified as new information is received. Games can have one, multiple, or no Nash equilibria.

Games can be one-off or repeated, whereas electricity markets are infinitely repeated. In such repeated games, participants have a larger field of choice over strategy and can react to the past and present strategies of other market participants (J. Lin & Magnago, 2017). Participants can also unilaterally or collectively game the system by exploiting its vulnerabilities, where there is a case for maximising their profits.

The microeconomic theories in this section provide the conceptual foundations for the three applied theoretical bodies that directly frame the research. Electricity market design theory (Sections 2.5 and 2.7) applies competitive market and welfare concepts to day-ahead market design and the challenge of integrating VRE. Political economy theory of regional energy integration (Section 2.8) extends the oligopoly and market power framework to the EAPP context. Sovereign governments exercising strategic behaviour are analogous to

Stackelberg leaders in bilateral contracting. VRE integration theory (Section 2.6) applies price formation and investment theory to the specific dynamics of high-VRE grids.

Short-term electricity markets are repetitive games under which strategic gaming and designing to avoid gaming can be applied. The next section discusses short-term electricity markets

CHAPTER 2.5: SHORT-TERM ELECTRICITY MARKETS

2.5.1. Short-Term Markets

Short-term markets are the backbone of liberalised electricity markets and have auctions in which producers and consumers of electricity are matched to determine the market-clearing price and quantity, and who among the participants qualifies to trade in each period (Graf, 2025). The market-clearing price is the price at which demand and supply equate; no supplier or buyer is willing to supply or buy more. These short-term prices provide a reference for long-term prices that determine the future buildup of system capacity. These prices should internalise the fact that electricity markets operate within physical constraints related to the nature of electricity, generation technology, demand type, and transmission and distribution lines.

There are two main approaches to short-term markets: the European and American approaches. In the European market, the system operator handles operating reserves away from the market after the energy market results are known. U.S. In the U.S., once the energy and reserves are secured, the system operator ensures the reliability of the system by factoring in network constraints. Once the energy and reserves are secured, the system operator ensures the reliability of the system by factoring in network constraints. These markets in the developed world benefit from a robust regulatory environment, advanced metering and grid infrastructure, and extensive interconnected financial systems that enable faster trade and clearing of transactions. These allow for continuous trading enabling efficient price discovery and risk management (Alshehri et al., 2017; Y. Wang, Liu, et al., 2023; Wolak, 2019; Z. Zhou et al., 2007).

Developing world markets, such as the EAPP, do not have such sophistication. Thus, they suffer from limited market depth, transparency, liquidity, and infrastructure. State-owned utilities trading through bilateral contracts dominate trade (Liao et al., 2025; Mabeba, 2024). Developing country markets are nascent, with limited integration of supporting financial infrastructure.

Research has shown that short-term markets have key design elements that determine how they operate (Graf, 2025; Perez-Arriaga et al., 2017; Silva-Rodriguez et al., 2022). These include the timeframe of market operation, locational applicability of prices and schedules, bidding formats, market clearing and settlement, and accounting for operational reserves. The following subsections delve into each of these aspects:

2.5.2. Time Frames and Pricing

The market timeframe is driven by the technical and physical characteristics of the respective grid. The consensus is that thermal-dominated markets are better served by day-ahead energy and reserve markets that allow for these two to be traded within the same auction or via different and sequential mechanisms. One day is sufficient to forecast and schedule thermal plants' commitment. Conversely, the economic dispatch in hydro-dominated markets can be calculated over a longer period, such as a week, for the case of Brazil (Perez-Arriaga et al., 2017). The EAPP market is hydro-dominated, allowing for longer periods.

Market timeframes have three essential aspects that must be defined: the time limit within which bids and offers for a specific period must be presented by market participants, the timelines and format of the correcting intraday energy market, and the settlement and dispatch period. A two-settlement system is commonly applied in day-ahead and real-time

markets. The day-ahead market clears the following day, whereas the intraday market operates continuously to adjust for deviations from the day-ahead market (Battula et al., 2020; Herding et al., 2023; Munhoz, 2021; Shin et al., 2023).

The two-settlement approach allows utilities to hedge against price volatility. The settlement and dispatch of traded energy are performed within predefined periods. Day-ahead markets traditionally have 24-hour blocks for which a price and quantity are defined, although shorter time blocks are common (sub-hourly) (Munhoz, 2021; Shin et al., 2023; Stoft, 2015).

The timing at which bids and offers can be given and readjusted by market participants without the intervention of the system operator is essential. The end of the period over which market participants can adjust their offers is termed gate closure. In the US, this occurs after the ISO clears the day-ahead market and develops the corrections needed to factor in transmission constraints, load forecasts, and RE production. Conversely, gate closure in European markets occurs after the closure of the last intraday session, over which trading in energy for the reference delivery period can occur. Italy has a day-ahead market that operates as an auction market, with bids allowed from 8 a.m. nine days before the delivery date to 12 p.m. one day before the delivery date (Perez-Arriaga et al., 2017). The results of the auction are delivered 55 min after closure. The auction selects bids and offers using the economic merit order and considering transmission constraints between Italy's different zones.

Intraday markets allow generators to make positive adjustments relative to the day-ahead market and allow the recovery of the demand-supply balance when the forecasted conditions differ. Generators are signalled on deviations. Deviations known in short notice imply the activation of expensive fast-start-up plants, whereas if the deviations are known

hours in advance, more economic inflexible plants can have their output adjusted (Munhoz, 2021).

To overcome the challenge of continuously varying real-time marginal costs (especially because of variable RE), time blocks must be averaged in intraday markets, and a marginal cost must be assumed for that period. These periods can be 5 min (as in the US) or 15 min (as in Germany and proposed for the EU) in balancing markets. Balancing resources are provided to better approximate the real-time market and allow the network operator (TSO) to balance the required ancillary services (Munhoz, 2021; Shin et al., 2023).

2.5.3. Locational Applicability

The pricing of electricity has locational dependencies related to the location of the generating plant, the load, and available grid infrastructure between the two. Pricing can either consider a detailed assessment of the transmission infrastructure or a simplified zonal approach that has price regions or zones (Perez-Arriaga et al., 2017). The detailed version is locational marginal pricing (LMP; nodal pricing), whereas the simplified pricing is the zonal approach. The two approaches can be compared by considering the efficiency of their short- and long-term price signalling, their computational cost and cost of implementation, hedging complexity, effect on geographical consumer discrimination, and impact on the liquidity of long-term markets. LMP is the predominant approach in short-term markets (Kaleta, 2020; Prashant, Siddiqui and Saxena, 2021; Ba and Tsuji, 2022; Wang et al., 2023; Tesfatsion, 2024).

Nodal pricing uses economic dispatch to arrive at locational marginal pricing at a given node in the grid. This corresponds to the price of consuming or delivering a unit of electricity to a specific node in the grid. The cost of electricity includes technical constraints,

economic costs, transmission line losses, and congestion attributed to the grid infrastructure for delivering a unit at a specific node. These prices convey efficient signals for economic decisions regarding short-term supply and demand (Tsfatsion, 2024; Y. Wang, Yang, Yu, et al., 2023b).

The nodal price comprises energy, congestion, and loss components (Ba & Tsuji, 2022; Kaleta, 2020; H.-F. F. Wang & Rastgoufard, 2006). The energy component is determined by the system-wide marginal cost of generation, assuming that there are no transmission constraints. The congestion component is a premium or discount that reflects the cost of transmission limitations. The loss component accounts for the transmission losses through heat.

Congested networks benefit more from the nodal approach than from densely meshed grids with minimal congestion (Neuhoff & Boyd, 2011). However, implementing nodal pricing is challenging because of the required harmony in different regulations and coordination among different institutions (Perez-Arriaga et al., 2017; Silva-Rodriguez et al., 2022). The nodal approach is well established in the America and more so in the United States. The nodal approach is well established in the America and more so in the United States. Nodal pricing provides economic signals that guide long-term grid investment and short-term grid operations (Z. Liu et al., 2024; Tsfatsion, 2024).

The zonal approach divides the grid into zones in which congestion is assumed to be negligible, and a price is assigned to each zone. A zone can be a region of a country, a country, or a set of countries, depending on the specific electricity network (Perez-Arriaga et al., 2017). The zones may vary depending on variations in demand and supply over hourly timeframes (Ambrosius et al., 2020; Kolsch et al., 2022). The differences in prices among zones correspond to the differences in transmission costs between the zones. This price

difference, or congestion rent, signals the economic value of the constrained transmission line. Where congestion occurs, the system operator re-dispatches the network and compensates the agent providing or withdrawing supply.

In a zonal market, the market clearing process involves a security-constrained economic dispatch modelled as a direct-current optimal power flow (DC-OPF) problem. These clearings aim to minimise the total generation cost subject to generation limits and network constraints within the zone. Zonal pricing aims to better manage transmission constraints than a uniform pricing system, while reducing the computational complexity and market coordination of a nodal pricing approach (Eicke & Schittekatte, 2022; Moretto & Pollitt, 2026)..

Zonal prices provide more stable signals to investors and offer more uniform pricing to consumers than nodal prices. Some of the consumer pricing discrimination of nodal pricing can be overcome by averaging nodal prices in an area of interest, should the regulator be inclined (Perez-Arriaga et al., 2017).

Zonal pricing has the potential to misprice within a zone in which the uniform regional price may not accurately represent intra-zonal price differentials. This can lead to inefficient siting of VREs, which will not ensure the lowest-cost generation (Katzen & Leslie, 2024). The delineation of price zones is also a complex task, and research is leaning toward flexible zones that change with dispatch efficiency, considering grid constraints (Moretto & Pollitt, 2026; Risanger et al., 2025). Zonal pricing has the additional weakness of allowing arbitrage opportunities. Power producers can increase prices in the day-ahead market and reduce prices in the real-time market to exploit price differentials (Sarfati & Holmberg, 2020).

The zonal approach has been adopted in European markets, including France, Germany, and Italy, using different approaches to zoning (Eicke & Schittekatte, 2022). Zonal pricing is likely to be the dominant pricing approach in the EAPP given the different pricing structures in different countries.

2.5.4. Bidding Formats

Bidding formats must account for the true costs of delivering energy to a customer, including the physical constraints of the generation plant. The bid format can vary from simple hourly price-quantity bids to bids that declare related economic and technical constraints (Cserecsik, 2021; Y. Wang, Yang, & Yu, 2023). Price–quantity bids offer a stepwise quantity of electricity that the agent is willing to buy or sell at given prices. Complex bids have the price-quantity in addition to parameters such as minimum income conditions. These can influence strategic bidding behaviour and introduce non-convexities (Y. Wang, Yang, & Yu, 2023). For markets with energy storage systems, different strategies are required for charging and discharging (Fang et al., 2022).

In developed markets, two formats are applied: the simple European power exchange (PX) format and the more complex American ISO bidding format (Perez-Arriaga et al., 2017). The European PX approach attempts to minimise the intervention of the system operator. According to researchers, this approach also aims to separate the bid format from the plant’s technical characteristics, freeing market agents from trading in a compulsory pool. The original aim of the European market was to have day-ahead auctions with price-quantity trades. This approach requires that market participants internalise the operational costs and constraints related to the dispatch of traded energy within a simple price-quantity bid or offer. This task is made more difficult by a more uncertain dispatch resulting from more RE in

grids. European markets have introduced block orders, which imply putting in an all-or-nothing offer on a specific amount of electricity supplied or requested at a given price, thereby allowing the internalisation of economic and operational costs.

In the US, the ISO bidding format for power generation is based on complex multipart offers that require generators to submit bids representing the technical constraints and operational costs of their units. Economic dispatch is determined after assessing the bid components, including the energy curve, hourly no-load costs, start-up costs, minimum and maximum economic operational levels of the plant, ramp rate of the plant, minimum and maximum run times, minimum downtime, start-up time, cooling time, and notification time (Perez-Arriaga et al., 2017). Generation offers are required to provide these details in addition to price–quantity offers. This approach does not allow the demand side to adjust consumption in response to market signals. A complex bid format is required to match complex generation bids and provide an accurate valuation of demand for cases in which demand can be shifted (Y. Liu et al., 2015). In the EAPP, constrained electricity production capacity and limited market participants will impact offer prices because of insufficient supply.

For the EAPP, the appropriate bidding format for the initial day-ahead market is likely to follow the European PX approach with simple price-quantity bids, rather than the more complex U.S. ISO format. This is due to the limited number of market participants and the need to allow for a gradual transition from bilateral contracting. As the EAPP market matures and more complex participants enter the market, the bidding format will need to evolve toward more complex offers that can capture the operational flexibility of these technologies (Cserecsik, 2021).

2.5.5. Market Clearing and Settlement

Market clearing is conducted to match bids and offers for generation and demand. The market-clearing price is defined by the intersection of the supply and demand curves and represents the price at which, given the volume of trade, all offers for demand lower than that price and all supplies supplied at prices higher than that price are rejected (Stoft, 2015). The market-clearing price is defined as the price at which demand equals supply in a market (Stoft, 2015). The ISO performs market clearing using sophisticated algorithms to maximise social welfare within the operational and physical constraints of the grid (Mittal & Singh, 2025; Silva-Rodriguez et al., 2024).

The settlement process follows the selection of offers and determination of the market-clearing price. Subsequently, the settlement follows the option of uniform pricing (non-discriminatory pricing) or pay-as-bid (discriminatory pricing) (M. Wang et al., 2022). In uniform pricing, generators are compensated using the price of the marginal generator, irrespective of their bid. While this approach encourages generators to reveal the true marginal cost and bid lower, market participants can learn and anticipate pricing to maintain a high uniform cost over many rounds.

In a pay-as-bid settlement, each generator is paid as much as its bid, with the supply successfully included in the dispatch (Pinson, 2018). This can encourage more complex strategic bidding, such as China's weighted-average settlement pricing (M. Wang et al., 2022). It should be noted that even in this case, suppliers will adjust their bids to the incentive of being paid as-bid by bidding at levels closest to the predicted market-clearing price and not in line with their marginal cost. This earns them a margin over their production cost.

There is no evidence that pay-as-bid auctions lead to lower prices than uniform pricing. Both are susceptible to manipulation by market participants, who adjust their offers or bids in accordance with the rules of either approach, as anticipated by the revenue equivalence theorem (Morey, 2001).

Comparing uniform pricing and pay-as-bid, the bidding behaviour of participants is affected by the '*winner's curse*' in a pay-as-bid system, and the effect of inframarginal capacity in uniform pricing (Morey, 2001; Perez-Arriaga et al., 2017). The ability to set market prices for inframarginal plants (plants that have bids lower than the market-clearing price) in uniform pricing motivates a firm with a diversified portfolio of plants to bid higher for plants that are likely to be marginal at the time of dispatch. This will increase the earnings of the plants that are inframarginal in the portfolio if the marginal plant sets the market-clearing price.

In a pay-as-bid auction, the fact that bidders are paid the price they suggest pushes all bidders to bid higher, assuming that there is imperfect information on the total volume of demand available. If all bids are accepted, lower-priced offers would be compensated at a low price, and higher-priced offers at a higher price. This situation is known as the winner's curse (Morey, 2001). Additionally, it is argued that the cost of participation is raised by pay-as-bid auctions due to the requirement to guess the market-clearing price (Perez-Arriaga et al., 2017). This will lead to smaller, less financially strong participants consolidating or being pushed out of the market and result in less competition and higher market concentration.

Settlement systems can also be viewed as single- or multiple-settlement systems (usually two) (Morey, 2001). In the single-settlement system, day-ahead bids and offers are used to schedule but are priced at the real-time price at the time of dispatch. The two-settlement

system has day-ahead energy bids and offers scheduled and priced energy a day ahead of dispatch. Deviations from this day-ahead schedule are priced in real time (*ex post*) and settled separately in the intraday/balancing market (J. Lin & Magnago, 2017; Stoft, 2015). There may also be a three-settlement system with day-ahead, hour-ahead, and real-time settlements, similar to the two-settlement approach (Morey, 2001). The two-settlement approach was the most prevalent.

Single settlements, while simple to implement, are vulnerable to gaming, in which bidders with sufficient scale can adjust the availability of units to influence real-time prices after the day-ahead schedule is defined. This may be mitigated by well-defined penalties, which may introduce complications related to disputes and lobbying for exemptions and modifications (Morey, 2001). In two-settlement systems, day-ahead bids are financially binding and cannot be altered by bidders or the market operator. This provides stability in pricing on both sides and a good signal for expected income and risk mitigation.

2.5.6. Accounting for Reserves

Real-time demand and supply usually deviate from the planned supply in short-term markets, necessitating the provision of operational reserve capacity. The North American Electric Reliability Corporation (NERC) defines operating reserves as

“That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection.”
(NERC, 2021).

Reserves are standby generation or demand response that can be called upon to cover supply-demand mismatches over a given timescale (Silva-Rodriguez et al., 2024).

Operating reserves can be spinning or non-spinning. Spinning reserves refer to generation that is synchronised to the grid and ready to supply the grid during the disturbance period, and the load that can be fully withdrawn from the grid during the disturbance period. These reserves can also be considered primary, secondary, and tertiary frequency support (Perez-Arriaga et al., 2017). System operators acquire operating reserves to overcome short-term contingencies (fault events such as loss of generators and transmission lines and short circuits) and avoid load shedding or complete system failure. The value of supplying energy or reserves is mutually dependent, as generators can ideally choose to offer either. Thus, supplying one represents the opportunity cost of not supplying the other.

This implies that a proper definition of the operating reserve demand curve must ensure that the value of the reserve to the system is captured and that the opportunity cost of supplying the reserves, together with the scarcity of the reserve, should be factored (W. W. Hogan, 2013). The system operator defines the minimum reserve level for which a bid is placed for the entire quantity at a price equivalent to the value of the lost load (VOLL). The inelasticity of reserve demand is a signal of the importance of security over economic efficiency to system operators.

Reserves can be procured through three approaches: separate capacity bids, co-optimisation, and scenario-oriented approaches (Kuttner, 2022; Naseri et al., 2023; Shi et al., 2021). Separate bidding allows reserves to be procured in parallel to energy. The European markets handle reserves by having separate sequential markets for reserves and energy. Market participants can withhold the supply of energy in favour of availing such capacity as reserves. The low frequency of occurrence of these markets is a drawback to the increased participation of VREs.

Co-optimisation involves joint optimisation energy and reserve requirements and bidding in one market, considering the opportunity costs of resources (Silva-Rodriguez et al., 2024). In the U.S. wholesale markets, to ensure that the opportunity cost of providing reserves is captured in energy prices, co-optimisation of energy and reserves in the market is done. Alternatively, a price top-up on the energy price and the resultant sum being the price of the reserve (Perez-Arriaga et al., 2017).

The scenario-oriented approach procures reserves as needed to cover contingencies and VRE fluctuations while considering network constraints (Shi et al., 2021).

2.5.7. Congestion and Access to the Transmission System

In a short-term market, the value of transmission lines, transmission losses, and the right to utilise transmission lines become important considerations. Transmission lines have two limits: a physical limit and a contingency limit (Stoft, 2015). Physical limits restrict the amount of power that a line is supposed to carry without violating its integrity. They prevent the overheating of the line, instability of power flows, and low-voltage conditions at the ends of the line. Some of the physical limits include thermal limits related to line losses and line resistance which causes heating and potential breaking or melting of the line. Reactive power (and thermal) limits refer to the level of reactive power required in the transmission line to maintain real power flow without breaching thermal limits. Finally, stability limits specify the maximum phase difference and corresponding power flow between the voltage at the generator and the load to allow for an optimal current flow and prevent line losses.

In contrast, contingency limits are drawn from physical limits and are set to ensure that the physical limits are not reached when there is a disturbance in the system, such as a

line or generator going out of service. These limits are expressed in MWs and vary depending on how the transmission line is operated (Stoft, 2015).

Congestion pricing is defined as the difference in energy cost between two locations in a grid caused by the physical limits in the transmission system. Congestion occurs when the transmission system to carry the volume of trade in energy between two locations is exceeded by the demand between the said locations because of its physical constraints (Kunz & Zerrahn, 2015). Transmission becomes scarce in such a scenario and is traded in the form of access rights, separate from the energy market. Financial transmission rights (FTRs) provide financial instruments that allow hedging against the financial risks associated with congestion (Di Persio & Fraccarolo, 2023). These rights can be computed using a centralised or bilateral approach. In the centralised approach undertaken by the ISO, power is sold at higher prices to cover the cost of congestion in the system, which allows for fewer arbitrage opportunities and places less burden on buyers and sellers (Stoft, 2015). The ISO may then redispatch generators within the control area to minimise congestion. The bilateral approach allows for arbitrage opportunities between market actors at different ends of the transmission line, and congestion rent is collected by selling transmission rights.

VREs place demands on the transmission system because good wind and solar resource areas are typically located far from load centres, where energy is consumed. This is also the case for other renewable sources, such as hydropower and geothermal. VRESs also tend to be installed in more decentralised locations.

Congestion management approaches must be fair, fast, effective, and motivational (Dehnavi et al., 2022). Congestion can be managed by system operators by using preventive or curative measures. Preventive measures are undertaken during or prior to daily market clearing. Implicit and explicit auctions for transmission capacity have been applied in Europe

for cross-border transmission capacity and in the PJM market in the U.S. using a nodal pricing approach (Deng et al., 2010; Kumar et al., 2005).

Curative congestion management measures include the redispatch of power plants based on final market commitments and counter closing and are usually applied in Europe (Kunz & Zerrahn, 2015). Congestion management can be achieved by defining a congestion index to identify zones that are prone to congestion (Dehnavi et al., 2022). This allows ISOs to focus their efforts and undertake generation rescheduling and load shedding to manage congestion.

Congestion management approaches can be categorised into three types: (i) demand-side management approaches, such as zonal pricing, market splitting, and the use of flexible demand; (ii) generation-side management approaches, such as the optimal location of generation and generation rescheduling; and (iii) transmission-side management, such as flexible AC transmission systems (FACTS), optimal power flow approach, and available transfer capacity (ATC) approaches (Manohar et al., 2022). Similar concepts have been discussed in literature (Kumar et al., 2005; Pillay et al., 2015; Yusoff et al., 2017).

The U.S. FERC defines two types of congestion revenue rights: financial transmission rights (FTRs) and flow-gate rights (FGRs). These have two intentions (i) create property rights to incentivize compensation for transmission usage, investment and facilitate creation of an efficient congestion management protocol, and (ii) provide risk management capability to market participants, allowing them to hedge congestion rent risk (Deng et al., 2010). FTRs can be allocated directly through historical rights or through auctions for transmission capacity or a combination of both approaches. FTRs are ideal for converting historical entitlements to transmission capacity into tradeable rights, preserving the financial viability

of the right to access the transmission line while allowing new entrants to participate (Deng et al., 2010).

2.5.8. Contemporary Challenges and Solutions in Short Term Markets

Researchers have investigated the challenges faced in short-term wholesale electricity markets to propose solutions to overcome them (Leslie et al., 2020; Papadaskalopoulos et al., 2019; Peng & Poudineh, 2019; Philipsen et al., 2019; Silva-Rodriguez et al., 2022).

The increase in VRE levels on grids has led to a greater focus on flexibility in energy, balancing, and capacity. Wholesale markets have tended to focus on the supply of energy because of the historical dominance of conventional power plants, which are predominantly state-owned. Further penetration of VREs would imply a reduction in the cost of energy and an increase in the value of balancing services and greenfield capital investments (Papadaskalopoulos et al., 2019). This may require the development of new segments to cover different timescales related to the demand for these services. These are foreseen to range from real-time to several years.

Further research has proposed shifting away from an energy-based market to the trade of power. This is argued will move away from the cost-inefficient requirement for reserve capacity. This capacity is required because of the overestimation of generator flexibility and non-representation of momentary load. This necessitates adjusted bidding, pricing, and clearing rules. A pricewise-linear power trajectory and a supporting bid that includes details on the capabilities of the demand and supply sides in terms of lower and upper production limits and ramping rates are proposed. These must be complemented by the marginal pricing of power profiles (Philipsen et al., 2019). Hydropower, storage, and flexible demand can be used to support such a power-based market to provide ramping capability that can increase

the flexibility of the schedule. The marginal cost is defined as the price of supplying 1 MW at a given location at the end of a given period.

The procurement of flexibility services over shorter periods is seen as a potential solution for the problem of procurement of these services by system operators based on their own projections and over prolonged periods. These requirements for these services are reported to vary in real time based on system conditions, such as inertia, demand levels, and VRE penetration. This system-state also changes rapidly. This situation results in over- or under-procurement of flexibility services (Papadaskalopoulos et al., 2019). A shorter procurement period for flexibility services would ensure efficient resource utilisation.

The pricing of energy in a traditional wholesale market omits certain costs, resulting in a loss of cost reflectivity, which is a key measure in electricity markets. This is especially true for demand-side response and energy storage. These costs include storage losses, load recovery effects, and fixed energy constraints (Papadaskalopoulos et al., 2019). Marginal cost pricing does not consider non-convex costs because it only matches energy supply and demand. The flexibility that demand can offer through downward regulation, which saves costs, is not valued or compensated. This is the same as the costs related to the standby operation of various conventional generation assets and their minimum operation level (Kuttner, 2022; Y. Wang, Yang, & Yu, 2023).

Price volatility in wholesale electricity markets has become a concern owing to the entry of VREs. They introduce rapid variations in demand-supply balances and, consequently, price. In times of high VRE supply, prices may go negative. Sudden dips in VRE supply can significantly increase wholesale market prices (Lau et al., 2023; Michaelis et al., 2024; Silva-Rodriguez et al., 2022). Volatility increases the need for better weather-

and-production forecasting, risk management, and optimal trading strategies (Z. Wang et al., 2024).

Wholesale markets operating based on simple demand-supply bids force participants to absorb the cost of complex operations in their bids. Participants then adjust to this by increasing their bid prices to cover this cost. The application of semi-complex bidding, in which, in addition to price, participants also reveal a bid including the operating characteristics of their demand or supply equipment, is considered. These bids include the mimicking of the operational conditions of a power plant in “complex orders” and “block bids.”. However, this may lead to inconsistencies between the cleared bid and the clearing conditions (Papadaskalopoulos et al., 2019).

Today’s wholesale markets are centralised because of the limited number of market participants. This often results in illiquid markets with sparse trading volumes. This results in gaps between orders. Traditional order book models are insufficient because they must account for sporadic order arrivals and cancellations within a short period. Illiquid markets make trade more costly because of a wider bid-ask spread. The risk of holding inventory and adverse selection is not well covered, resulting in higher prices (Bergault & Cognéville, 2024; Mohammadi & Hesamzadeh, 2022).

The recent increased deployment of RE in grids has led to the need to adapt markets to support the fluctuating supply from RE. The next section focuses on recommendations for adapting short-term markets to accommodate more variable RE.

2.5.9. Considerations in the Case of Short-Term Markets in Power Pools

The literature on short-term electricity market design for power pools converges with several design principles applicable to the EAPP context. The European power exchange (PX) model is the most tractable starting point for nascent pool markets. The model incorporates transparency, replicability, and depth of operational experience available from Nord Pool, EPEX SPOT, and OMIE (Meeus, 2020; Nord Pool Ricardo, 2021).

The academic literature on market design for high-VRE systems identifies three adaptations. Intraday markets to accommodate short-term forecast revisions; co-optimised reserves procurement to capture the flexibility value of the conventional baseload; and locational pricing signals to reflect the transmission constraints (D. Biggar & Hesamzadeh, 2014; W. W. Hogan, 2013). The Gulf Cooperation Council's (GCC) experience with market coupling is a good pointer. Hourly market coupling produces material welfare gains and emission reductions relative to bilateral trade (Petitet et al., 2025). The EAPP's planned day-ahead market should therefore be designed with structural capacity to accommodate the locational pricing and intraday functionality that higher VRE penetration will eventually require.

Power pools provide a larger power system built on higher levels of inertia, which allows for better grid stability and operation (Meeus, 2020). Short-term markets in power pools must consider trade challenges across national boundaries. These challenges include assigning the right to trade across borders, aligning market rules, defining border trade constraints, defining funding or payment for cross-border network costs, defining responsibility for system balancing and operation, geopolitical tensions, and ensuring adequate investment in power plants (Venizelou & Poullikkas, 2024).

To determine to whom the right to trade in a pool resides, it is necessary to consider historical rights. These rights have been the privileges of national utilities, as is currently the case in the EAPP. These rights are retained in the wholesale market, as they are traditionally based on long-term contracts with ongoing tenures (Petitet et al., 2025). These rights include the right to access the transmission system. Once transmission access rights are freed, they must be allocated to market participants. This can be achieved through auctions.

The definition of border trade constraints necessitates the definition of available transmission capacity or constraints and the allocation of congestion rent. These constraints can be a physical line or a critical network component that enables the transfer of electricity. The allocations can be related to the physical realities of the grid. Two different approaches can be used to estimate the available transmission capacity: flow-based and available transfer capacity (Aravena et al., 2021). The flow-based approach calculates virtual border capacities and flow distribution factors. An algorithm is then used to allocate these independent flows over different lines to maximise welfare (Meeus, 2020). Flow-based approaches in Europe use power transfer distribution factors (PTDFs) to dynamically estimate the possible flow at a given time. Flow-based approaches are well suited for high VRE grids and allow for the effective exploitation of transmission grid capacity (Shinde et al., 2023). Welfare improves with flow-based approaches.

The choice of pricing approach is essential. Pricing can be based on zonal or nodal pricing (Risanger et al., 2025). Zonal pricing defines a single price over a given pricing zone, typically a country. These are simple to implement but fail to reflect physical grid constraints. In contrast, nodal pricing accounts for transmission bottlenecks and losses. They provide clear signals for operational decisions and long-term investments. However, nodal pricing

requires complex data and computing requirements that may not suit regions with less infrastructure, such as the EAPP.

Trade across borders is normally before a short-term market is dominated by bilateral trades. These may reduce the depth of a short-term market. Integrated market coupling, in contrast, involves hourly trades based on day-ahead or real-time demand and supply. In the Gulf Cooperation Council, it was found that hourly market coupling resulted in greater welfare than bilateral trades (Petitet et al., 2025). There were more cost savings, emissions reduction and bigger volumes traded.

Transmission lines take longer to build than generation projects because of the complexities and uncertainties involved in developing a line. The cost of developing regional transmission capacities across countries is another consideration. The allocation of costs is subject to political considerations in the respective countries (Ragosa, 2024). In Europe, there are two approaches, depending on whether the project is of common interest or of interest between two countries. Projects of common interest to the pool are included in Europe's ten-year network development plan (TYNDP) (ENTSO-E & ENTSO-G, 2025). These projects benefit from accelerated licencing, financial incentives from the national regulators involved, and access to the Europe-wide Connecting Europe Facility (CEF) fund.

When two countries are interested in a project, they may enter into a cross-border cost allocation agreement (CBCA) in which the countries share the cost of infrastructure. This sharing is not necessarily linked to the amount of infrastructure in one country but can be flexible depending on the interests of the project's outcome and the funding capabilities of the participating countries. For example, the cost-sharing ratio between Italy and Greece for a 500 MW high-voltage direct current (HVDC) line is 75:25, enabling cheap power to flow to Italy through Greece from Eastern Europe (Meeus, 2020). In cases of disagreements, the

European Union Agency for Cooperation of Energy Regulators may mediate. The EAPP has interconnectors that are funded through development finance institutions and the respective governments.

The harmonisation of regulatory environments presents a challenge. Countries may have different support mechanisms for VREs, remuneration mechanisms for generation, and retail regulations. It is important to align regulations. The EAPP, through the Independent Regulatory Board (IRB), is working towards standardisation. Additional considerations, such as revenue sharing, cross-subsidies, and sovereignty, must also be addressed (Puka & Szulecki, 2014; Ragosa, 2024).

Power pools also require ensuring adequate investment in power plants (solving the “missing money” problem). This is especially important in the case of increased VRE on grids and associated instances of negative pricing. The implementation of capacity markets in parallel with energy-based markets could solve this. There are arguments in favour of and against such markets. Political considerations of incumbent generators, fearing blame for energy shortages and the need to compensate generation that is needed but used sparingly (mainly peaking plants), favour capacity mechanisms and bilateral trade (Meeus, 2020; Petit et al., 2025).

The handling of trade between two countries through a third country’s network is also problematic. The remuneration and allocation of risks for the wheeling of power in the third-party country must be addressed. This is the case in the EAPP for Ethiopia, which sells power to Tanzania through Kenya (RenewAfrica, 2025). Transit charges for such trades have been applied in Europe but were removed as they were an obstacle to trade (Meeus, 2020). Capped export prices were preferred but were subsequently abolished. Europe now operates an inter-TSO compensation scheme in which TSOs that cause international flows pay into a fund that

is used to compensate TSOs that host these flows. The funds are used to adjust network costs for consumers upward and downward in a zero-sum approach. The challenge of heterogeneous regulatory environments in the EAPP will stress trade through third parties (Elabbas et al., 2023).

CHAPTER 2.6: INTEGRATION OF VARIABLE RENEWABLE ENERGY IN ELECTRICITY MARKETS

2.6.1. Key Concepts in VRE Integration

Electricity markets are increasingly introducing variable renewable energy. The increased uptake of renewable energy is driven by cost reductions and the fight against climate change (Perez-Arriaga et al., 2017). VREs introduce challenges to the grid because they are non-dispatchable, weather-dependent, and geographically dispersed. Electricity markets were designed to consider conventional plants (hydroelectric, coal, gas, and nuclear plants); therefore, they must be adjusted to accommodate variable renewable energy. Renewables introduce variability, uncertainty, and reduce system inertia (Ejuh Che et al., 2025; Garg & Tyagi, 2024). The dominant forms of variable renewable energy are wind and solar energy.

Although variations in wind and solar production can be predicted over time because of their reliance on the movement of the sun, which is well understood, cloud cover and daily and seasonal variations in weather introduce uncertainty. Solar photovoltaic (PV) plants are affected by cloud cover over a day, and this may cover only a portion of a large plant, further increasing uncertainty in the production. Wind is less predictable than solar, but variations occur slower than in solar, and large changes could occur in hours as compared to solar, which may experience second-to-second changes owing to variations in cloud cover (Bird et al., 2013; Dong et al., 2019). Such effects of variation can, however, be minimised at the system level by geographically spreading the installation sites of these plants.

Variations in RE production pose a challenge in balancing the system and introduce complex power quality issues. Variations in production owing to wind gusts and cloud cover introduce voltage fluctuations, harmonic distortions, and flicker (Garg & Tyagi, 2024; Pithwa

et al., 2024). Additionally, spatial differences between the generation location and demand centres can lead to transmission congestion, which can curtail renewables.

Grids with more VREs have greater uncertainty in predicting market conditions, including transmission constraints (Perez-Arriaga et al., 2017). The system operator must ensure that sufficient resources are available on both the demand and supply sides to ramp up and down when wind and solar power vary. Conventional sources may also need to be curtailed in instances where demand is stable; however, wind and solar energy are experiencing higher-than-expected production. This may introduce curtailment costs and increase wear and tear owing to on- and off-cycling (Perez-Arriaga et al., 2017). Under such circumstances, short-term markets should incorporate approaches that enable participants to recover their costs.

Weather-dependent variable renewable energy sources have the advantage that, once installed, they have near-zero marginal costs (Bird et al., 2013; Stoft, 2015). This implies that the overall market-clearing price for energy is lower for a higher penetration of wind and solar in a grid (Banshwar et al., 2017; Rudnick & Velasquez, 2018). While this may be beneficial for consumers, it may pose a challenge to other generators in meeting their fixed and variable costs (Bird et al., 2013). There has been greater interest in capacity markets in the US to shore up revenues for plants, although such capacity markets are opposed by proponents of energy-only markets (W. W. Hogan, 2005). During hours of high variable RE production conventional plants are pushed out of markets by zero marginal cost plants due to the lower costs and the effects of the economic merit-order dispatch arrangement (Rudnick & Velasquez, 2018). However, these capacity mechanisms should be designed to minimise distortions and ensure that mature renewable energy technologies compete with other technologies in capacity markets (Perez-Arriaga et al., 2017). To motivate investors to commit to long-term capacity investments, capacity markets have been proposed in addition to energy markets.

A greater share of variable RE implies the need for more intraday trading to adjust the production schedule to the latest weather forecasts and resulting expected production. This requires near-real-time market options, wherein market participants can adjust their bids and offers. Gate closure should, however, balance the desire of the system operator for closure further away from real-time to allow efficient planning of reserves versus that of the market participants, who desire gate closure close to real-time to have more accurate forecasts. Such near-real-time closures may necessitate large reserve amounts, adding to the cost of system operation (Perez-Arriaga et al., 2017). The manner in which operating reserves are acquired should also allow for shorter timeframes between auctions.

The high penetration of variable RE introduces uncertainty in the prediction of market conditions and grid constraints. The time and locational granularity of market signals should increase in tandem with the increased penetration of variable RE. They argue that the design of short-term markets should be refined in terms of bidding formats, timelines, pricing, and clearing rules, and the integration of the short-term market with reserves and regulation/balancing markets (Perez-Arriaga et al., 2017).

A higher participation of VRE sources affects the need for more granularity in the locational pricing of electricity (Perez-Arriaga et al., 2017). The best wind and least solar sites were concentrated in specific geographical regions. If the increase in wind generation occurs faster than the increase in the necessary transmission capacity, congestion will occur. This implies that to achieve a higher penetration of variable RE, there is a need for more granularity in the pricing of network infrastructure and, thus, a higher spatial resolution of wholesale market prices. This implies that nodal or zonal pricing and related locational marginal pricing approaches would better support the higher penetration of VRE. This location-specific pricing allows for the incorporation of the cost of unique network resources required to support demand

or supply at a given point on the grid, ensuring full compensation to suppliers and cost-reflective pricing of demand and supply.

In terms of bidding formats, a higher penetration of renewable energy requires more detailed bids that include technical constraints of the power plants. The bidding process should combine the European Union (E.U.) and U.S. approaches. This will ensure that the transaction is neither oversimplified in its attempt to combine energy, reserves, and ancillary services into a simple price-quantity bid as the E.U. approach, nor will there be high top-ups paid for provision of these services as in the U.S. approach (Perez-Arriaga et al., 2017). The researchers add that the bidding formats should be reworked to take advantage of demand response and storage, and the flexibility that they provide in a grid. The bidding format should allow for more complex bids to provide participants with more flexibility in providing comprehensive bids. According to (Rudnick & Velasquez, 2018), demand response mechanisms are not yet a priority in the developing world, as they are in the developed world, as many countries still struggle to provide an adequate supply.

The co-optimisation of energy and reserve acquisition in day-ahead and intraday markets is recommended to improve the link between energy and reserves. This is especially true because fluctuations in renewable energy (RE) supply will mean a greater need for reserves. The acquisition of reserves also needs to be improved to allow for the full value of the reserve to a system at the time of need to be compensated (Perez-Arriaga et al., 2017). This could be energy, balancing services, voltage support, and other services that all need to be valued and compensated. Conversely, where these reserves are provided from fossil sources, VREs displace expensive fuel and emissions (Banswar et al., 2017).

Outside of short-term markets, (Perez-Arriaga et al., 2017) advise that in the balancing market, balancing energy should be procured from the most economic sources in real-time.

They argue that reserves as a product should be split into upward and downward reserves, which should be traded separately. This will allow for more specialised competition among unique reserves. These could be a suite of demand reserves for downward variations or generation reserves for upward variations. Additionally, (Perez-Arriaga et al., 2017) argue that plants with different response capabilities should be allowed to compete for the balancing service, thereby reducing the need to define different reserve products.

The volatility of renewable energy plant supply implies the continued need for peaking plants. These plants must recover their fixed operation costs as marginal cost-based markets will provide inadequate revenue because of price depression by near-zero marginal-cost variable RE. To motivate long-term capacity investments, energy-only markets must allow for the proper pricing of scarcity. Scarcity occurs when there are extended periods of low RE supply, requiring ramping up of supply by reserves. The price of supply at these moments needs to reflect the true value of the supply from peaking and reserve plants (W. W. Hogan, 2005, 2013; Rudnick & Velasquez, 2018). This well priced peaking supply will allow peaking plants to recover part of their fixed costs. On the convers, VRE generators should be exposed to the cost of the scarcity they produce as an incentive to encourage them to make more accurate production estimates.

Price- and quantity-based mechanisms are required to complement energy-only markets in the developing world and incentivise optimal capacity build-up (Rudnick & Velasquez, 2018). The development of capacity and balancing markets to support energy markets is proposed to ensure future investments in both conventional and renewable plants. As a second option, central planning or coordination solutions that have a single buyer who can then balance RE versus conventional capacity acquisition have been proposed (Sen, 2014). This has been

argued to have worked in Chile and Brazil, where auctions for both conventional and RE supplies have guaranteed generation adequacy (Rudnick & Velasquez, 2018).

The increasing penetration of VREs has introduced grid stability challenges, as VREs do not provide a full set of ancillary services that conventional plants have traditionally delivered. In the next subsection, the literature on ancillary services in grids with VREs is discussed.

2.6.2. The role of Ancillary Services in VRE Penetration

Ancillary services (AS) are required for the reliable operation of a power system and to ensure the security of supply (Demoulias, Malamaki, Gkavanoudis, Mauricio, Kryonidis, Oureilidis, Kontis, & Ramos, 2020; Ehnberg et al., 2019). The AS maintains the grid within operating limits to guarantee supply. They are targeted at maintaining the frequency and voltage within acceptable ranges and restoring them to these ranges after a system disturbance occurs. In this sense, AS are viewed as voltage control and frequency response by deploying reactive power sources and black-start capabilities (Holtinen et al., 2012). AS tend to suffer from underinvestment because individual customers can benefit from using them without necessarily paying for them (Barroco, 2021).

Ancillary services are specific to a grid and are defined according to the needs of the grid. Nevertheless, different general definitions have been attempted. Holtinen et al. (2012) defined AS as being availed mostly in the transmission system and classified into three i) services for congestion management, ii) non frequency AS such as grid restoration and voltage control, and iii) frequency balancing AS comprising containment reserves (FCR), restoration reserves (FRR) and replacement reserves (RR).

An alternative grouping of ancillary services is frequency control services, voltage control services, including reactive power support, and emergency services, such as black start capabilities (Banshwar et al., 2017; Ehnberg et al., 2019). This is similar to the ancillary services that the system operator in the Philippines contracts (Barroco, 2021). Frequency control services include regulation, load following, and operating reserves. Regulation reserves involve the maintenance of a real-time balance between demand and supply. These are categorised again based on response time as primary (response within seconds) or secondary reserves (5–10 min response time).

Load-following reserves are deployed to maintain interconnection frequency in a control area by matching supply and demand. They are different from frequency controls, as they maintain the balance over a longer period. Operating reserves are those that are availed by a powerplant in a ready but unloaded state and can be deployed to restore system frequency immediately after an outage. These operating reserves can be 10-min synchronous (spinning) or non-synchronous reserves, and 30-min (replacement) reserves. The time indicates the period within which they must be fully deployed from the time of instruction by the system operator. The time responses of different AS are summarised in **Table 2-1**.

Table 2-1*Time response of different AS*

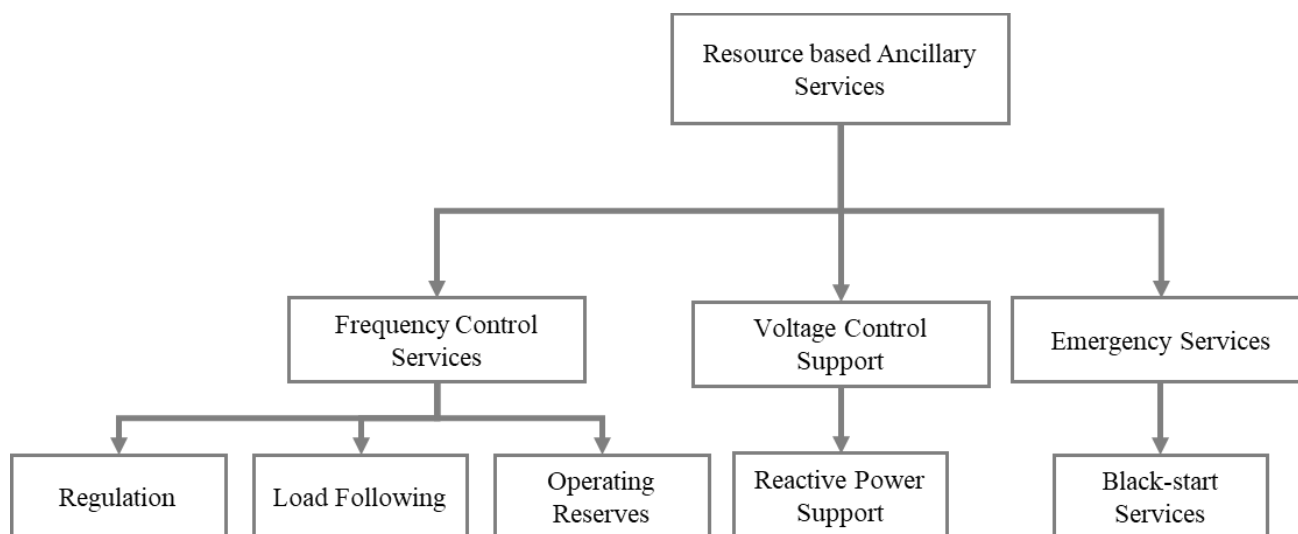
Type of AS		Requirement	Response Speed	Duration	Dispatch Frequency
Regulation		Normal Operation	< 1min	Mins	Hrs to days
Load following			< 1min	Mins	Hrs to days
Operating Reserves	TMSR ¹	Abnormal operation	Secs to <10 mins	10 min to 2 Hrs	Hrs to days
	TMNSR ²		<10 min	10 min to 2 Hrs	Hrs to days
	Replacement Reserves		<30 min	2 hrs	Hrs to days
Reactive Power Support		Normal operation	Secs	Secs	Continuous
Black-start Services		Abnormal Operation	Mins	Hours	Months to Yrs

Note. Adapted from (Banshwar et al., 2017)

Voltage control services are required to prevent voltage collapse and are provided by the deployment of generation, transmission, and system, and reactive devices that inject or absorb reactive power to maintain voltages. Devices such as load tap transformers, capacitor banks, and synchronous condensers are used. These services are normally included in the requirements of a powerplant to be connected to the grid. Black start capability is the ability of a plant to restart itself or restore the grid without any external electricity source. The facility providing this capability should have sufficient real and reactive power to reenergise and restart other generators (Banshwar et al., 2017). The categorisation of AS is depicted in **Figure 2-5**.

¹ Ten minute synchronous response

² Ten minute non-synchronous response

Figure 2-5*Diagram of classification of ancillary services**Note.* Adapted from (Banshwar et al., 2017)

These AS are typically provided by synchronous generation, as in conventional plants. Further penetration of renewable energy power plants, especially wind and solar, implies lower AS available in the system. This as VREs replace conventional supply. This could be overcome by using conventional plants to provide AS, the incorporation of utility-scale storage systems provided by third parties, or the aggregation of AS from DREs at the distribution level (Holttinen et al., 2012). Different approaches have also been applied in markets to forestall the need for AS. These include the requirement of performance bonds for generators, charging of a penalty for inability to provide scheduled supply, imbalance penalties, and application of ex-ante pricing for pricing or penalising non-performance (Banshwar et al., 2017).

The further penetration of VRE in the grid, with characteristics that do not provide many AS capabilities, makes it necessary to factor in these services. The non-dispatchability of VRE sources implies the need to react dynamically to the state of the system. VRE sources

can also participate in AS provision (Lambriex et al., 2022; Ullah et al., 2024), especially with the application of distributed renewable energy sources (DRES) in medium- and low-voltage grids (Arosio & Falabretti, 2023). Some inverter-interfaced VRE sources have functionalities that can provide AS. There are also some requirements within grid codes for VRE sources to provide some level of system support services to be eligible for a connection licence. This extends to more advanced markets with a causer pays principle for disturbances that require ancillary services to be overcome.

Stability concerns extend to transmission systems, including reactive and active power control, voltage sag and swell, and optimal power flow. Flexible alternating current transmission system (FACTS) devices are required to address these issues. FACTS devices have different types and are classified into four types (Sharma et al., 2024). A common FACTS device is the static synchronous compensator (STATCOM), which is used as a shunt compensator to control reactive power, suppress harmonics, and provide voltage support in transmission systems (Ma et al., 2015; Sharma et al., 2024; Xu et al., 2020).

Demand response is an alternative approach for handling ancillary service needs. Flexible, controllable, or interruptible loads reduce the need for ancillary services. This demand allows grid operators to minimise the amount of installed capacity for operational reliability, reduce the operating cost of production and reduce curtailment of VRE sources (Lamadrid & Mount, 2012; Ribó-Pérez et al., 2021). Demand response can provide cheaper flexibility than peaking generators and provide economic gains to the system and consumers providing flexible demand. It is also a new business opportunity that may lead to cheaper AS compared to generators. AS acquired from flexible demand can also reduce the market power of other AS providers (Canizes et al., 2022; Ribó-Pérez et al., 2019, 2021).

The demand response participation in markets is limited by AS market designs that are more suited to generators (Arosio & Falabretti, 2023; Ribó-Pérez et al., 2021). These often have large minimum bidding capacities or long time-maintenance requirements. A minimum value of 1 MW is cited for European grids, whereas Asian, Oceanic, and American grids have a minimum of 0.1 MW. The latter allows more medium-scale consumers to access the AS market. Otherwise, these cannot be typically provided by individual consumers, creating a need for demand aggregators that may have the scale to participate in the AS markets (Burger et al., 2017). Aggregators interact with system operators, consumers, and markets, intermediating to capture the value of consumers to the electrical system. They are also referred to as demand response service providers and can compete with other balance service providers in a market (Ribó-Pérez et al., 2021). There is a need to standardise the definitions of AS, especially in power pools. There is also a need to incorporate more digitalisation and ICT in networks to enable better management of distributed resources and enhance aggregation capabilities (Arosio & Falabretti, 2023).

AS can be procured through auctions, direct bilateral contracting, or wholesale markets. This can be done in real-time or forward markets. Real-time markets match supply and demand in real-time, and the system operator must acquire AS when needed. Forward markets operate in day-ahead or hour-ahead projections, with bids being placed within these timeframes. The dispatch of energy and AS in a forward market can be sequential, simultaneous, or simultaneously co-optimised (Banshwar et al., 2017). In the sequential dispatch, energy is first cleared, followed by AS in a separate AS-only market. The simultaneous approach has separate mechanisms with separate offers for energy and AS. Energy and AS dispatch are not optimised.

The simultaneous co-optimised approach involves the co-optimisation of energy and AS dispatch.

Remuneration for AS can be determined using three approaches, similar to the remuneration approaches for energy in wholesale markets. These are (i) the pay-as-bid approach, in which the provider is paid the price that they offer in the market; (ii) a regulated price, where the regulator or TSO sets a fixed price; and (iii) using a common clearing price that corresponds to the most expensive accepted bid. This compensation should cover the cost of making ancillary services available, the cost of using ancillary services, and variable costs related to AS use (Holtinen et al., 2012).

A study on the design of financing contracts for ancillary services in the Philippines found that revenue contracts needed to be long-term, firm, and technology-specific cost recovery mechanisms with new entrants to incentivise financing (Barroco, 2021). The researcher found that remuneration levels in the Philippines were low and that there was an exclusive focus on incumbent generators to provide ancillary services.

In addition to the technical effects on the grid, VREs have commercial effects. VREs enter the market at low marginal prices, which causes significant price fluctuations in electricity markets. The next section reviews extant price research on price fluctuations in markets with high VRE penetration.

2.6.3. Price Fluctuations in High Penetration VRE Grids

Grids with high penetration levels of VRE sources experience fluctuations in prices, particularly those operated based on marginal pricing. This particularly for grids operated based on marginal pricing. When there is favourable weather, such as summer seasons for solar and

periods of high wind for wind, such systems produce electricity at high levels. VREs can influence overall market prices depending on the time and level of penetration (Owolabi et al., 2023). In general, higher VRE penetration levels are associated with lower electricity market prices (Mwampashi et al., 2021; Zarnikau et al., 2020).

In the energy-only South Australian market, with a VRE penetration of more than 50%, it was found that a high penetration of VREs caused an increase in price volatility, although with reduced instances of extremely high prices and increased instances of extremely low prices (Rai & Nunn, 2020). In the US electrical grid, across different ISO areas, a higher penetration of VREs was found to result in lower electricity prices (Owolabi et al., 2023). European markets have also shown that price volatility increases with higher VRE penetration (Cevik & Ninomiya, 2022; Ciarreta et al., 2020; Dong et al., 2019; Pereira da Silva & Horta, 2019).

Variations in pricing over time and the level of VRE penetration are influenced by several factors and differ between grids (Cevik & Ninomiya, 2022). These factors include the availability of flexible generation, patterns of demand, and weather (Mwampashi et al., 2021). When flexible generation is available, these generators can be ramped up and down to release demand or increase supply, thereby damping price changes. In certain instances, VRE resource fluctuations align with the demand profile, such as a high demand for electricity in summer for cooling and high solar or wind production during peak demand periods at night (Astaneh & Chen, 2013). Holding electricity demand, crude oil import prices, and average temperature constant, (Cevik & Ninomiya, 2022) found no statistically significant relationship between VRE penetration and price volatility in the European energy market. However, the researchers found that VRE penetration has an impact on price volatility at higher quantiles.

Alternatively, other studies have opined that price volatility introduced by the high penetration of VRE implies a type of stability in itself. The extremes produced by high VRE penetration present opportunities for market participants to identify business opportunities and avoid risks (Dong et al., 2019). Wang et al. (2024) found that the price fluctuations reduced once certain thresholds of RE penetration were reached.

A study of five U.S. ISOs found that price volatility decreased as VRE penetration increased. This aligns with modern portfolio theory, which states that diverse unrelated assets operating together lead to reduced price volatility (Owolabi et al., 2023). However, literature has found that VREs have a negative effect on pricing volatility in higher quantiles (Cevik & Ninomiya, 2022).

Negative pricing is an issue of interest in wholesale markets. This refers to a situation in which the dumping of produced electricity has more value than the creation of electricity (Sewalt & De Jong, 2003). Negative pricing is a common phenomenon in grids with high VRE penetration owing to the low marginal cost of generation, mainly from wind and solar. Power producers accept negative prices when the opportunity cost of shutting down a power plant is much higher than the cost of dumping the produced power. This phenomenon was also observed before the introduction of VREs when must-run power plants operated during periods of low demand.

Negative pricing manifests in periods of low demand matched by high supply availability from VRE. This is mainly related to the high penetration of wind into the electricity grid (Dong et al., 2019; Owolabi et al., 2023). This negative pricing can be exacerbated by the limited transmission capacity, limited flexibility of powerplant operations, and limited availability of storage.

Negative pricing results in operational problems in energy risk management because of complications in handling value-at-risk (VaR) calculations, invoicing, and cash-flow projections. VaR is a risk-management statistic that describes the size of an investment, including its daily or weekly profit and loss (Edwards, 2017). Negative pricing complicates this consideration.

Research has also shown concern regarding the likelihood of new investments materialising because of low prices related to the high penetration of VREs. This phenomenon is described as the ‘cannibalisation effect’ (Reichenberg et al., 2023). Depressed market prices due to the high penetration of VREs have been observed to cause a deflation of the value of VRE assets as they cannibalise their own revenues, failing to cover their costs through a short-term market (Brown & Reichenberg, 2021).

The use of contracts for differences (CfD) and other financial hedges has been cited as a possible means to overcome the impact of negative pricing (Ason & Dal Poz, 2024). CfD provides price support and covers VRE traders from the volatility of pricing in wholesale markets. They provide predictability for future revenue streams. Two-way CfDs are signed between a generator or trader and a public body that sets a strike price after a competitive tender. The trader or generator then trades electricity in the wholesale market but settles the difference between the strike price and the market price with the public entity. This limits the roof prices for generators while enabling them to have stable revenues. When the market price is below the strike price, the generator receives the difference; when the strike price is lower than the market price, the generator returns the difference (Veenstra & Mulder, 2024). The literature also highlights the risk of CfD entering over a longer period, causing market distortion when it deviates significantly from the strike price and denying consumers welfare

(Favre & Roques, 2023). Further proposals for a hybrid of conventional CfDs and forward contracts have been proposed to mitigate revenue risk and provide incentives (Schlecht et al., 2024).

The negative pricing literature establishes a causal mechanism. Near-zero marginal-cost VRE output displaces higher-cost generation in the merit order at market clearing. The simulation in Chapter 4 operationalises and tests this in the EAPP context. The cannibalisation effect predicts that as VRE penetration increases, the market value of each additional unit of VRE falls relative to the system average price (Reichenberg et al., 2023). This is because VRE generators collectively depress the price in the hours when they generate the most. This signals that the EAPP's planned VRE expansion, if implemented at a rapid pace, will create systematic investment viability risks for new generators.

The cannibalisation effect is a consequential mechanism for the economic viability of VRE investments in the EAPP and merits careful analytical development. The market value of wind energy declines systematically as the share of wind in total generation increases (Hirth, 2013). At low penetration, wind generators earn close to the average market price. At high penetration, they generate predominantly during hours of low prices of their own creation. This compresses their market value below the average. In markets where both technologies are deployed, their outputs partially overlap (midday solar combined with high wind), creating frequent periods of very low or negative prices (Hirth, 2013).

This wind-solar interaction is directly relevant to the EAPP, where large volumes of wind and solar are expected. This becomes a disincentive for investors when the long-run equilibrium value of VRE, the market value at which the marginal investor is indifferent between investing and not investing, falls below the levelised cost of electricity. The contracts

for difference mechanism reviewed in Section 2.5.3 is a policy instrument designed to protect VRE investors from cannibalisation.

In the following section, we review the role of geothermal energy in wholesale markets with high VRE levels.

2.6.4. Geothermal Energy in Wholesale Electricity Markets

Geothermal energy has a distinct position in the wholesale electricity market merit order. Geothermal plants are dispatchable with low variable costs and are technically designed for continuous baseload operation. They are commercially similar to nuclear plants, as they have high capital costs, low fuel costs, and high utilisation requirements (DiPippo, 2015).

In a marginal cost-based day-ahead market, geothermal plants dispatch ahead of all hydrocarbon-based generation. However, as VRE penetration increases, hours arise in which zero-marginal-cost wind and solar fully meet demand. The marginal price is pushed to or below zero, excluding geothermal from dispatch. This has been observed in Kenya with the curtailment of geothermal by wind, although due to a must-run condition on wind (EPRA, 2024).

Geothermal plant curtailment poses a problem, as steam must be vented. Sustained venting risks altering reservoir pressure and reducing long-term well productivity (Dobson, Ayling, et al., 2020). At low utilisation factor geothermal operators cannot recover the fixed costs of their investment from energy revenues alone. Geothermal operators would thus suffer the missing money problem. Under high-VRE penetration, geothermal plants are not price competitive at the margin and would be curtailed in favour of wind and solar in an energy-only market.

Zero-marginal-cost wind and solar depress the market process at baseload and non-peak hours. This commercially excludes geothermal from the market, even when it is technically ready (Dobson, Ayling, et al., 2020; Millstein, Mills, et al., 2021). This renewable-versus-renewable displacement was empirically observed on the Kenyan grid and documented for California's geothermal fleet (Dobson, Dwivedi, et al., 2020a). Curtailment rates in California increased sharply after 2015 with the expansion of solar capacity.

Research on geothermal curtailment in the US has found that flexible operation during negative-price hours improves energy value by only 1–2 USD/MWh, which is insufficient to offset the well integrity risks involved (Millstein et al., 2021). Therefore, the most effective regulatory response is a dispatch guarantee or minimum generation commitment, rather than operational flexibility.

Kenya's geothermal fleet currently operates as baseload under bilateral PPAs that guarantee offtake regardless of marginal market conditions. The transition to a day-ahead market threatens this guarantee. Chapter 3 considers a geothermal must-run sensitivity scenario in the EAPP market. The renewable-versus-renewable tension is largely absent from the European-dominated VRE integration literature, where the framing is primarily variable renewables versus fossil fuels. This gap in the literature represents a theoretical contribution of this research, distinct from the extant literature.

CHAPTER 2.7: APPROACHES IN DEVELOPING COUNTRY MARKETS

2.7.1. Introduction

Developing-country electricity markets continue to evolve toward wholesale electricity markets. However, this evolution occurs at different speeds in different regions and countries (Foster & Rana, 2020; Sioshansi et al., 2006). While Latin America and the Caribbean, Central Asia, and Europe (developing) have progressed steadily towards competitive markets, Africa, South Asia, and the Middle East generally still have bilateral long-term contracts between power producers and utilities. Some countries, such as Vietnam, Pakistan, Egypt, Nigeria, Mexico, and Ukraine, have made steps to shift to wholesale power markets. Other developing countries, such as Chile, Russia, Brazil, Turkey, India, Colombia, and Guatemala, already have wholesale power markets (Rudnick & Velasquez, 2018).

The increasing penetration of renewable energy in grids in the developing world will also require these markets to evolve toward wholesale markets, considering developments regarding variable renewable energy. This section discusses the readiness for wholesale markets in the developing world and preparations to integrate more renewable energy. The prerequisites for a wholesale market are first defined, followed by recommended approaches, including regional integration. Finally, a literature review of the Eastern African power pool and its readiness for a wholesale market is presented.

2.7.2. Prerequisites for a Wholesale Market

Some prerequisites for establishing wholesale electricity markets may preclude the establishment of such markets. These include a financially healthy power sector, a competitive generation sector, adequate in-country institutional and governance systems, and a stable

overall macroeconomic, political, and social environment. Few developing countries meet all these conditions (Rudnick & Velasquez, 2018).

A financially healthy power sector implies a creditworthy and financially sustainable distribution utility, which is the main buyer in the market. The stability of the distribution utility determines whether payments are honoured and the resulting confidence that the market has in transactions. There is a need for cost-reflective tariffs and the operational efficiency of the distributor (Huenteler et al., 2017). The integrity of payments across the whole value chain of generation, transmission, distribution and retail is an important requirement. The enforcement of payments must be strong. This remains a challenge in many developing countries with utilities facing arrears from their customers and distributors in arrears to power producers (Rudnick & Velasquez, 2018). The problem is exacerbated by the volatility of exchange rates, as the supply from power producers is often denominated in foreign currency, while customers pay for supply in local currency. Reforming and stabilising the distribution segment should be prioritised to achieve cost recovery before the introduction of wholesale markets (Victor et al., 2006).

The second precondition for a wholesale market is a competitive generation subsector. This competitiveness is determined by the size of the system, market structure, margin between demand and supply, state of transmission bottlenecks, and competitiveness of upstream fuel markets. In terms of size, 1000 MW is accepted as the minimum for unbundling, while 3000 MW is considered the minimum for a wholesale market (Rudnick & Velasquez, 2018). These minimums have been met by EAPP countries. These sizes ensure that there is enough room for competition and that the fixed costs of setting up a wholesale market do not outweigh the efficiency gains. Based on experience in Ukraine, the ease of market entry of new power producers and their ease of access to transmission and contracting with buyers is the main

determinant of the feasibility of wholesale markets (Maurer & Barroso, 2011). The market structure must have at least four competing producers at peak, shoulder, and valley hours for effective competition, which is influenced by the generation mix and the share of baseload plants (Rudnick & Velasquez, 2018). The more baseload in the mix, the fewer peaking or flexible plants compete to set the marginal price. The reserve margin (difference between installed capacity and peak demand) should be considerable to allow for competition between suppliers with excess capacities. This requires a margin of at least 10% of the peak demand for effective competition. To avoid the abuse of market power, the transmission network should be adequate and well-functioning to avoid bottlenecks that lead to scarcity. An adequate transmission network allows for better utilisation of resources and reduces local market power. Competition and transmission inadequacy are problems faced by many developing country wholesale markets.

The third precondition for a wholesale electricity market is strong institutions and governance of a country, which affect the general investment climate of a country (Rudnick & Velasquez, 2018). Issues such as the independence of the judiciary, corruption, clarity of legislation on property rights, political stability, and risks of nationalisation are considered. Proper institutional and regulatory frameworks should be established before wholesale electricity markets are set up. However, these should also be strengthened by a careful design of the wholesale market to avoid lawful abuse. Fair and fast dispute resolution mechanisms should be available, and the enforcement of legal decisions should be enabled. Well-functioning regulatory environments reduce risk perceptions, encourage investments, and reduce financing costs.

The fourth pre-condition is a stable political, macroeconomic, and social environment. Multiple countries in the developing world have experienced turmoil, which has led to difficulties in successfully operating wholesale markets (Rudnick & Velasquez, 2018).

These prerequisites may not be available in one country but may be apparent at a regional level. This has led to the consideration of regional markets, which have become a growing trend in the developing world (Vanheukelom & Bartelsmann-Scott, 2016). Markets in East, South, and West Africa, South Asia, and Central America are under development. The potential of regional integration to support wholesale markets in the developing world is analysed in the next section.

2.7.3. Regional Integration

There is an increasing trend toward the regional integration of power grids in the developing world, with examples of the Southern African, West African, and Eastern African Central American and South Asian power pools (Vanheukelom & Bartelsmann-Scott, 2016). These have evolved from bilateral trade to organised power pools. Intercountry trade allows for arbitrage between neighbours with low and high generation, allowing for the optimisation of resource use and guaranteeing the availability of supply (Rudnick & Velasquez, 2018). Smaller countries may benefit from trade with larger countries, such as Nepal trading with India, which has a much larger grid. However, power sectors must be financially sound and creditworthy for trade to be effective. Three conditions must be met for the operationalisation of a regional power pool: the presence of cross-border interconnection infrastructure, a common legal and regulatory framework, and a multi-country organisational structure (Vanheukelom & Bartelsmann-Scott, 2016).

Five recommendations have been made for the developing world regarding the formation of regional markets (Oseni & Pollitt, 2016). First, there should be a broader arrangement or pre-agreement on regional free trade between countries in the prospective power pool. Second, there should be adequate transmission capacity within and between countries, enabled by interconnection agreements that ensure the expansion of intercountry transmission lines. A case of insufficient transmission capacity limiting the evolution of the South African power pool from bilateral contracts into a power pool has been cited. Third, economic and technical benefits must exist, such as the possibility of arbitrage between high and low electricity prices. Fourth, strong, independent, and efficient institutions must govern trade and ensure the effectiveness of the electricity market. An efficient market operator that can oversee and sanction participants to avoid abuse, such as through predatory pricing, should be in place. Additionally, external regulatory oversight from agencies, such as competition authorities in free trade areas, can be essential for checking market power. An appropriate combination of regulations and markets should be developed (Oseni & Pollitt, 2016).

Finally, regional markets should develop organically in size from a few to many countries (Medinilla et al., 2019). Regional power markets of two to three countries are suggested as a good starting point. They argue that this will allow the demonstration of the benefits of trade and avoid prolonged initial development periods. However, this organic development should be guided by clear timebound roadmaps (Oseni & Pollitt, 2016). They recommend that regional trade should develop and evolve toward more efficient day-ahead and real-time markets. The involvement of international organisations in the provision of development support for building the necessary capabilities required for developing regulations (Oseni & Pollitt, 2016). Research on African power pools and the investment needed to activate

them stresses the need for various development support institutions to coordinate the different roles they play (Medinilla et al., 2019).

The literature on regional power pool formation highlights the role of financial architecture in sustaining pool development. Power pools in the developing world are heavily dependent on donor funding for both infrastructure investments and institutional capacity building (Barnett, 2014; Medinilla et al., 2019). This exposes the pool to the policies and plans of donors. Pool investments stall when donor priorities shift, and the design of pool institutions may reflect donor preferences rather than the operational needs of member countries.

The SAPP's success can partly be attributed to the sustained engagement of development partners. Donors provide capital for transmission lines, and technical assistance for market design, and regulatory capacity building (Prinsloo, 2019). The EAPP has benefited from similar support. The literature recommends that regional pools include mechanisms for multi-country cost sharing on transmission interconnection projects to reduce the political negotiation costs of advancing interconnection projects that benefit multiple countries but are physically located in one (Meeus, 2020; Ragosa, 2024).

2.7.4. Transitioning to Short term Markets

Transitioning markets to wholesale markets can be fraught with systemic, institutional, technical, and economic challenges. These include reduced investment in the initial setup period, challenges in controlling market abuse, and identifying and correcting market design flaws. The gradual introduction of competition in generation is the first step. This should be followed by open access to transmission and distribution grids, enabling multi-buyer trading to replace single-buyer models, establishing an independent system operator, and prompt payment of power producers (Rudnick & Velasquez, 2018). It is necessary to establish credible

regulatory frameworks, robust infrastructure, and transparent market operations (Chattopadhyay & Klein, 2021; Pownall et al., 2021; Venizelou & Poullikkas, 2024).

Competitive trading should be introduced only after a period of bilateral trade between multiple consumers and sellers and when the utilities have proven to be creditworthy. This was also observed during the formation of European wholesale markets (Meeus, 2020). The introduction should be gradual to provide time for the regulator to deal with system flaws. Ongoing monitoring of the system is essential for its identification and correction (Chattopadhyay & Klein, 2021). The set of acceptable market outcomes should be defined in advance, as well as the outcomes that necessitate regulatory intervention and the form of that intervention.

Monitoring and regulatory oversight of markets are important for successful market operations. Monitoring ensures that any abuse of market rules or design flaws is detected early and corrected, whereas regulatory oversight ensures that conditions for strong competition prevail and that dominant positions are not abused by participants when competition is not strong. Constant monitoring is necessary to detect abuse because market power can be exercised over short periods of time owing to scarcity (Rudnick & Velasquez, 2018). However, regulatory oversight should not introduce unnecessary complexity that stifles market activity but should be swift in correcting or seeking restitution (X. Lin et al., 2022). The regulator should be trustworthy in terms of adjudication and impartiality, and considerate of the interests of all market participants.

The question of how to treat existing power producers with long-term supply contracts during the transition to wholesale markets is important. Accordingly, the integration of these contracts into the wholesale market requires stranded-cost mechanisms. The exercise of market power should also be checked by the regulator and ensure sufficient transmission capacity to

avoid the exercise of local market power (David & Wen, 2001; Zhao et al., 2023). A simple solution to tame the exercise of market power is to have more producers and consumers. Argentina broke its generation utility into 38 unique and privately owned generators. This led to each having less than 14% market share and thus minimal market power. The UK broke the utility into three and ended up with dominant utilities that continued to exercise market power until they were further broken (Rudnick & Velasquez, 2018).

Vesting contracts have been proposed to provide investors with risk management capabilities during the transition to wholesale markets. Vesting contracts are assigned to a generation unit before it is sold and committed to the buyer to sell a significant portion of electricity at a given price, even after purchase, as a precondition to the sale (Wolak, 2003). These contracts not only provide price stability in the wholesale market but also guarantee income for the investor in the power plant, shielding both from the fluctuations of the spot market for the quantity that is contracted. The use of vesting contracts is also recommended as a solution to the regulator's tendency to introduce price caps when prices rise sharply because of scarcity. The introduction of caps blurs price signals and eliminates upturns that motivate long-term investments in new-generation plants. The successful use of vesting contracts in Turkey's transition allowed the recovery of stranded costs (Rudnick & Velasquez, 2018). It is recommended that customer-facing entities purchase at least 80 % of their energy needs in forward markets one year in advance (Besant-Jones & Tenenbaum, 2001).

Short-term markets face more VRE resources and must trade within a short timeframe. This implies the need to integrate automation, forecasting, and digital infrastructure to support sub-hourly trade and quick response (Y. Guo et al., 2024). Fluctuations in prices require accurate price and load forecasting to ensure the economic efficiency of participants and efficient market operations (Ehsani et al., 2024; Qiu et al., 2022). The increase in VREs

demands flexibility to overcome imbalances in demand and supply. This can involve the consideration of battery storage systems and demand response (Finhold et al., 2023).

Wholesale short-term power markets often exist in power pools. In the next subsection the EAPP is discussed together with the SAPP and the anticipated Africa Single Electricity Market (AfSEM)

2.7.5. The Eastern Africa Power Pool

The East African Power Pool (EAPP) was established in 2005 by Burundi, the DRC, Egypt, Ethiopia, Kenya, Rwanda, and Sudan. Tanzania, Libya, Uganda, and Djibouti later joined (Medinilla et al., 2019). The EAPP is a specialised institution of the Common Market for East and Southern Africa (COMESA), which provides oversight and political support from member states. While Ethiopia, Kenya, and Egypt played leading roles in the formation of the EAPP, there is currently no lead country in the EAPP, which may explain the delays in advancing the pool.

The objectives of the EAPP are to promote investments in generation, transmission, and distribution; develop a pooling framework at the regional level for electricity; and coordinate the region's long-term development (Medinilla et al., 2019).

The peak supply in East Africa was reported to be 7800 MW in 2018 and expected to grow to 17800 MW by 2025 as peak demand grew from 7000 MW to 14400 MW (Power Africa, 2018b). This implies that there were power surpluses that are expected to be mainly in Ethiopia, Kenya, and Uganda, as deficits occur in Rwanda and Tanzania (Power Africa, 2018a). This mismatch implies that there are opportunities for regional trade (Oseni & Pollitt, 2016).

In terms of the cost of supply, the East African countries portray cost differentials in the weighted average costs of producing a unit of electricity across all generation technologies, as

summarised in **Table 2-2**. This implies that there is an incentive to have regional trade, and these differentials indicate the possibility of countries trading (Power Africa, 2018b). The differential in Tanzania and Ethiopia energy prices suggests that trade between the two countries would be beneficial. It was estimated that Tanzania would need 500 MW to 800 MW within the medium term, which could have been supplied from EAPP members with oversupply (Power Africa, 2018b). This need has since been overcome with the commissioning of the Julius Nyerere Hydropower plant in 2024. On the other hand, Rwanda, which was also expected to have a deficit, could also be covered by its neighbours in the Nile basin sub-region.

Table 2-2

Anticipated generation costs (2018-2022) in East African Countries and the supply demand balance

	Generation cost (USD/kWh)	Surplus/ Deficit (TWh)
Ethiopia	10	3.7
Uganda	10.5	1.2
Tanzania	11.7	-1.5
Rwanda	12	0.1
Kenya	13.8	0.3

Note. Derived from (Medinilla et al., 2019)

The EAPP is reported to be struggling in the development and maintenance of the required infrastructure for generation, transmission, and distribution that supports a regional market (Medinilla et al., 2019). However, the installed capacity in the region was expected to increase sufficiently to support regional trade. There was opportunity to improve the prospects of regional trade in the EAPP by executing priority projects, including fast-tracking the Ethiopia-Kenya-Tanzania-Zambia transmission links and sub-regional transmission links in the

Nile basin (Kenya-Burundi-Rwanda-Congo-Uganda-Tanzania) (Power Africa, 2018b). The 500 kV high-voltage direct current (HVDC) line connecting Kenya and Ethiopia and the 400 kV line to Tanzania from Kenya are reportedly under construction (Medinilla et al., 2019). Other interconnections exist and have been used by countries to trade power bilaterally (Magochi, 2014).

Most utilities that may participate in regional trade in the EAPP are state-owned and prone to political interference and rent capture (Medinilla et al., 2019). They recommend that the creation of power pools requires working around and within incentive structures influenced by the politics of the electricity sector of cooperating countries.

It is further noted that up to 80% of the population in the EAPP, equivalent to 200 million people, did not have access to electricity. This may introduce a conflict of interests in countries that need to decide whether to sell power to their neighbours or expend power to increase electricity access to their population. The same scenario presents itself when local industries expand and require more electricity, making it more attractive to utilities than regional trade. The sudden increase in capacity in a country, such as is envisioned when the Great Ethiopian Renaissance Dam and the Grand Inga Dam (in the DRC) are built. This will alter the market dynamics in the EAPP (Medinilla et al., 2019).

The EAPP plans to establish a regional trading regime by 2025, moving away from the current bilateral arrangements between countries. Structurally, the EAPP established its operational headquarters and an independent regulatory board in Addis Ababa, Ethiopia. Ethiopia exercises dominance and uses the EAPP to politically assert itself regionally, a situation that may not bode well for regional trade (Medinilla et al., 2019). They add that the institutions of the EAPP, such as the Regional Market Operations and Control Centre, are centralised in Ethiopia, further consolidating their influence. The spat between Egypt and the

Nile basin countries over Nile water rights and their use for power generation also complicates integration efforts (Medinilla et al., 2019). Finally, the continued vigour of participation of member states in the EAPP is determined by their national interests.

The simulation conducted in this study is directly based on the EAPP context described in this section. The power plant data, demand profiles, and generation costs used in the simulation are drawn from the same national master plans that describe the EAPP's expected generation fleet as of 2025 (EAPP, 2023; ERA Uganda, 2016; MoE, 2022; MoE Tanzania, 2020; Rwanda Energy Group, 2022). Therefore, the simulation represents a direct operationalisation of the EAPP context described in the literature. The generation cost differentials shown in **Table 2-2**, with Ethiopia at the low end and Kenya at the high end, imply that a regional market would create welfare transfers between countries. The constraints on EAPP development documented in the political economy literature, including governance limitations, transmission constraints, and national interest considerations, are reflected in the modelling assumptions and qualitative validation described in Chapter 3.

2.7.6. The Southern Africa Power Pool

The EAPP and SAPP are intended to be coupled with the completion of the Zambia-Tanzania interconnector (EAPP, 2024a). The SAPP is a 12-member pool divided into three control zones operated by the utilities in Zambia, Zimbabwe, and South Africa as system operators (Elabbas, 2023b). It is the most advanced and oldest power pool in Africa. The SAPP has a functional market operator based in Harare, Zimbabwe. The market operator collects trading information, runs the competitive day-ahead market, and schedules power exchanges between the control areas. The SAPP operates bilateral, day-ahead, balancing, and intraday markets.

In planning the SAPP, a regional master plan for generation and transmission is already in place, with a set of criteria for the selection of priority projects. The countries use these as a guide for developing their own internal expansion plans. This contrasts with the EAPP which has national plans that are then harmonised to a regional plan.(Elabbas et al., 2023). When the two pools are coupled, it is necessary to align planning processes. However, neither pool has the authority to develop regional transmission expansion plans or to propose new interconnecting lines. This presents a challenge in the cost allocation for interconnection projects (Elabbas, 2023b). The availability of funds for interconnecting projects depends on the ability of the two interconnecting countries to raise funds. This has resulted in delays in actualising interconnector projects crucial to the advancement of trade in the power pools.

These two power pools are also being considered at a wider continental level under the Africa Single Electricity Market (AfSEM). The next section provides an overview of AfSEM.

2.7.7. The Africa Single Electricity Market

The African Union has plans to implement a single electricity market across the continent. This is to be achieved on the back of regional economic blocks and their associated power pools (Kyriakarakos, 2022). Regional markets provide locational and temporal benefits to national electricity markets, ensuring the security of supply and reducing costs. The African continent has five regional power pools, and several cross-country associations and regulatory bodies have targeted enhancing regional trade.

The Africa Single Electricity Market (AfSEM) was launched in 2021. It aims to provide a marketplace for electricity trade between the countries of the African continent. To achieve this, it was noted that there was a need to enhance and modernise the power systems of the continent. The development of a Continental Power System Masterplan was subsequently

agreed upon. This would focus on the development of new power plants, new interconnectors, and the modernisation of existing transmission lines (AU, 2021). The AfSEM is targeted to be fully operational by 2040. The development of AfSEM will influence the policy and regulation of the EAPP as an attempt is made to harmonise across the continent's power pools.

CHAPTER 2.8: POLITICAL ECONOMY OF THE EAPP

The political economy of the EAPP has been analysed, and institutional constraints rather than technical or economic limitations are binding impediments to pool development (Elabbas, 2023a; Oseni & Pollitt, 2016). Three structural prerequisites for successful power pool integration were identified. These include a clear and binding market development timetable, institutional bodies with delegated authority to act on technical matters without political approval, and a minimum threshold of private sector participation to create market depth and reduce the concentration of state-owned utilities.

Against these criteria, the EAPP falls short. Market development timetables have repeatedly been revised without penalty; the council of ministers remains the highest decision-making organ, requiring political consensus for technical changes; and IPP participation is not yet authorised in cross-border trade (Elabbas, 2023a; Oseni & Pollitt, 2016). The EAPP's membership spans countries with active and historical bilateral disputes, particularly the Ethiopia–Egypt conflict over Nile waters (Medinilla et al., 2019). This prevents the EAPP from acting as a neutral technical body and forces pool decisions into political arenas where energy trade is used for diplomatic leverage.

The welfare gains from regional integration are not evenly distributed, with large exporting countries (principally Ethiopia) capturing the bulk of the generation revenue gains, while smaller importers bear the political risk of energy dependence (Prinsloo, 2019). This distributional asymmetry, rather than disagreement about the efficiency benefits of pooling, is the principal obstacle to member-state commitment to the EAPP market development agenda.

Research on SAPP, EAPP, and WAPP has identified ineffective regional governance and flawed regional trading rules as hindrances to a well-designed regional trading system (Elabbas, 2023a). Power pools in Africa have issues, including the non-cost reflective selling of electricity in some countries, which affects integration efforts. This is especially likely to lead to an increase in costs in the subsidised market. Some countries still have monopolistic utilities that are the sole off-takers. Countries that dominate installed power capacity tend to have more market power in pools. Egypt exercised this power in the EAPP. These dominant utilities and countries exercise political influence in the pools, limiting moves toward liberalisation (Elabbas, 2023a). He further found that members that are independent of regional trade may join efforts to defend their interests. National interests and sovereignty are used as excuses to shoot down the liberalisation efforts of incumbent utilities. An example of blocking the Ethiopian Grand Renaissance Dam by Egypt in the EAPP master plan is cited. The case of Ethiopia exercising dominance over other members of the EAPP is also highlighted. There is also the threat of withholding supply to an importing country for political reasons (Oseni & Pollitt, 2014, 2016). The exporting country may also develop revenue that is dependent on the importing country.

The EAPP lacks an authoritative regional body to back its developments and match them to its member countries. This presents a significant political problem in decision-making and coordination. The EAPP infrastructure development is fragmented as it does not align perfectly with the regional economic communities. Subregions in the EAPP have made significant progress in building infrastructure. For instance, countries in the East African Community have made more progress in building interconnecting transmission lines. The EAPP is thus seen as a political organisation that will need political support or a change in

protocol to give more autonomy to the pool secretariat to decide matters without the need for a ministerial gathering (Elabbas, 2023b).

The EAPP also makes major decisions (technical or otherwise) decided by the political level, interfering and slowing down decision-making. Decision-making protocols that would de-politicize decision-making are recommended. Hurdles in the EAPP political conversations, such as Ethiopia wanting to centralise the institutions of the EAPP at Addis Ababa against the wishes of Egypt and Rwanda that were reported to want to host some of the institutions (Elabbas, 2023a).

He argues that independent power producers (IPPs) should be admitted into the EAPP to introduce competition to the utilities, allowing flexibility of trade without compromising national agreements. This has been cited as the case in the SAPP. The inclusion of IPPs in the market also increases market liquidity and reduces market concentration by increasing the number of participants. Additionally, market surveillance for players exercising market power should be pursued (Elabbas, 2023a).

The importance of creating and adhering to a clear and detailed market reform and development timetable for the countries in the pool is stressed (Oseni & Pollitt, 2016). They recommend that power pools should begin with a small member group and allow for organic growth in membership.

Energy security in countries is mainly viewed from the perspective of having sufficient local generation to meet local demand. In power pools, this perspective is threatened because generation and power over its use may be exercised by a neighbouring country. The political costs of power pools are rarely acknowledged (Barnett, 2014). This includes providing on country political power over another in terms of exposing one country to the political stability

of the other, where infrastructure, especially generation plants, are based across the border. This extends to the need to incur political capital against local groups that may, for instance, impede regional transmission line development. The same political consideration also plays a role in tariff rationalisation in a pool.

Governments are argued to often fall back to national least-cost power development plans as compared to joint regional power expansion plans. This is especially the case when there is contention over projects of regional significance being undertaken in one country. An example is the development of the Grand Ethiopian Renaissance Dam (GERD) hydropower plant on the Nile River, which had Egypt and Ethiopia disputing. Egypt being opposed to the dam actively blocked the EAPP power master plan which had included the dam.

Power pools, including the EAPP, rely heavily on donor funding from multilateral development banks, regional banks such as the African Development Bank, and Western nations. This affects the design and decision-making in the pool. The strength and further development of the SAPP have been due to support from lending institutions that provide grants for technical support of the governance of the institution. The support and governance structure is argued to be disconnected from the social political context but rather based on a pure techno-economic context. The way political power is wielded and who wields it is not factored into technical support. This leads to delays and inadequate systems (Barnett, 2014).

The political economy literature on the EAPP contains some contradictions. On the one-part researchers argue that the path to a functional EAPP runs through accelerated regionalisation, IPP admission, secretariat autonomy, and clear reform timetables (Elabbas, 2023a). Other researchers argue the opposite, that African power pools are driven by donor and dominant-country interests, and that decentralised bilateral arrangements would more

effectively advance energy security and climate goals (Hancock, 2024; Odetayo & Walsh, 2021).

The political economy literature also has direct implications for two specific research choices that require explicit justification. First, the political reality that countries with surplus generation prioritise their own demand before exporting during scarcity, regardless of marginal pricing (Barnett, 2014; Medinilla et al., 2019). This 'first-serve local demand' behaviour implies that technical transfer capacity may be limited by local needs and the political willingness to permit unconstrained cross-border flows. Second, questions on national interest considerations, energy security concerns, and geopolitical constraints must be addressed to specifically capture the institutional and political realities that a simulation cannot model. This would introduce a political constraint on the EAPP model.

Three propositions synthesise the political economy literature and frame the analytical approach of this research. The governance structure of the EAPP, specifically, the ministerial-level approval requirement for technical decisions, constrains pool development more than the technical market design (Elabbas et al., 2023; Oseni & Pollitt, 2016). The welfare and political distribution in the EAPP will determine the speed and form of market development more than the efficiency argument for pooling (Barnett, 2014; Prinsloo, 2019). A pure quantitative review of the EAPP market would exclude the politics of the pool. This would imply a lack of grounding in reality. This is a methodological rationale for applying a sequential explanatory mixed-methods design in this study.

CHAPTER 2.9: RESEARCH VARIABLES

The literature reviewed in this section provides the theoretical grounding for the research variables defined in the conceptual framework (Section 2.1.2) and operationally specified in Chapter 3. The independent variable, VRE penetration, is grounded in the VRE integration literature of Section 2.5, which establishes VRE penetration as the primary driver of the merit order effect, negative pricing, and dispatch displacement (Holttinen et al., 2021; Owolabi et al., 2023; Sewalt & De Jong, 2003). Installed capacity is used instead of energy output. This is because policymakers can directly control this through licencing and auction targets. Thus, it is a more actionable basis for the sensitivity analysis. The specific focus on wind and solar follows the convention in the integration literature (Holttinen et al., 2021; Migliari et al., 2024).

The operationalisation of VRE penetration as installed capacity rather than energy output is based on the planning and market design literature. The literature on VRE integration differentiates between capacity- and energy-penetration. These differ as VRE capacity factors differ from conventional plants and curtailment increases (Holttinen et al., 2021; Leal et al., 2023). Both metrics are considered in this study. This distinction is important because the same VRE energy output can be achieved with different installed capacities. This depends on the technology mix, geographic resources, and market implications.

Electricity pricing is operationalised as the hourly marginal clearing price in EUR/MWh, which is grounded in market design theory (Sections 2.3 and 2.4). The clearing price is the mechanism by which short-term markets achieve efficient dispatch and provide investment signals (D. R. Biggar & Hesamzadeh, 2025). This variable also portrays the negative consequences of high VRE penetration through negative pricing (Sewalt & De Jong, 2003).

Efficiency is assessed through the frequency of ceiling-price hours (signals capacity adequacy problems) and negative-price hours (signal overinvestment and revenue shortfalls for generators). These are relevant for assessing the investment viability of the EAPP market under different VRE penetration scenarios.

The operationalisation of dispatch as full-load hours and awarded energy is grounded in the VRE integration and capacity economics literature. The utilisation factor of a power plant is an important financial viability metric for generation investors. Low dispatch levels render investments unviable (IRENA, 2023).

The stability of supply, operationalised as ceiling-price hours, is grounded in scarcity pricing theory and developing-country energy security literature. The frequency with which ceiling prices (maximum possible pricing) are achieved signals supply insufficiency. This also indicates the ability to supply reliable energy in the EAPP as desired under SDG7 (Stoft, 2015; W. W. Hogan, 2005; World Bank et al., 2023). The peak price being tied to the value of lost load (VOLL) which prices the economic value of the consumer lacking supply. The literature on energy-only market design argues that scarcity prices are essential for providing investment signals for peaking capacity to recover their fixed costs (W. W. Hogan, 2005, 2013).

CHAPTER 2.10: SUMMARY

Chapter 2 reviews the literature across six areas that inform the three research questions, research design, and variable selection of this study. This section summarises the learnings from each area and identifies the gaps in existing knowledge that the research addresses.

2.10.1. Evolution of Electricity Markets

Electricity markets have evolved globally from vertically integrated monopolies to competitive wholesale structures, with African markets progressing at varying and incomplete rates (Kapika & Eberhard, 2013; Rudnick & Velasquez, 2018). The thirteen EAPP countries span the full spectrum of this evolution. Uganda and Kenya have progressed furthest toward liberalisation, whereas Ethiopia, Tanzania, and Rwanda retain more centralised structures.

This heterogeneity creates a regulatory harmonisation challenge in establishing an EAPP day-ahead market. The literature confirms that the bilateral contracting framework, which is dominant in the EAPP, will not support higher levels of VRE generation. A competitive short-term market is the necessary institutional response. The review also confirms that incomplete sector reforms limit VRE integration. Incomplete reforms retain contractual rigidity that prevents merit-order market clearing of VRE resources (Iychettira, 2021).

2.10.2. Economic Theory and Short-Term Market Design

The microeconomic theory reviewed in Section 2.3 establishes that electricity markets are oligopolistic. They have few competing generators holding significant market power potential. Auction designs and regulatory monitoring are, thus, critical for market integrity. The Bertrand price-competition model most closely approximates the marginal-cost bidding in

a competitive day-ahead market. The collusion model identifies the risk of tacit coordination among EAPP utility participants.

Section 2.4 identifies the key design elements—timeframes, locational pricing, bidding format, settlement, reserves, and congestion management—in the short-term market design literature. The European PX-style approach is highlighted as appropriate for the EAPP's early market phase. The congestion management discussion is particularly consequential: uniform single-zone pricing significantly overstates the supply security benefits of pooling compared to what zonal or nodal pricing would reveal.

2.10.3. VRE Integration and Geothermal

The VRE integration literature establishes the three dependent variable relationships in the research. These include declining average prices, declining conventional plant utilisation, and improving security of supply. The review identifies a gap in theory, the renewable-versus-renewable gap. This gap highlights the competition for dispatch between VREs and geothermal. The existing literature frames the VRE integration challenge as VREs versus fossil fuels. A similar tension was observed in U.S. markets (Millstein, Dobson, et al., 2021). Section 2.5.4 establishes the literature foundation for this tension and the research's theoretical contribution.

2.10.4. Developing Country Markets

The literature on developing country markets identifies four prerequisites for a successful wholesale electricity market (Rudnick & Velasquez, 2018). These include a financially healthy power sector, a competitive generation sector, adequate in-country institutional and governance systems, and a stable overall macroeconomic, political, and social

environment. The EAPP partially meets them at the regional level, even when individual countries fall short. This review confirms that the EAPP's development trajectory is a day-ahead market launched alongside bilateral contracts (Nord Pool Ricardo, 2021). The short-term market is expected to grow as legacy PPAs expire. This is consistent with the documented pattern of Latin American and European market transitions. The SAPP comparison confirms that regional market success requires three elements that the EAPP currently lacks. These are adequate transmission interconnections, delegated institutional authority, and private sector participation.

2.10.5. Political Economy of the EAPP

The political economy literature establishes that governance and institutional design are binding constraints on EAPP development. The ministerial-level decision-making structure prevents the secretariat from acting on technical matters at the pace required for market operations. The literature identifies a contradiction between the pro-integration position (Elabbas, 2023a) and the pro-bilateral position (Hancock, 2024).

This section finds that governance is the binding constraint in the EAPP and not technical parameters. Distributional concerns regarding who gets to build more VREs and which country and energy security concerns of countries will shape market development more than efficiency arguments. There is a need to combine quantitative and qualitative methods in the study of the EAPP short-term market to produce policy-relevant findings.

CHAPTER 3 RESEARCH METHODS AND DATA COLLECTION

CHAPTER 3.1: INTRODUCTION

This chapter discusses the research approach and design, including the quantitative and qualitative aspects of the research. The study was conducted using a mixed-methods sequential design, which was chosen to improve the internal validity and practical relevance of the study (Dossett et al., 2020).

The quantitative part involved the use of a model to run simulations of the EAPP market for 2025 under base- and high-VRE scenarios. The simulation research design and the simulation process using the agent-based simulation approach are described as appropriate for responding to the second research question. Agent-based modelling was chosen to better portray the complex relationships and interactions between market participants in a wholesale market in a power pool. The AMIRIS wholesale electricity market model was adopted and adapted for this study. A description of the expected agents in the EAPP market is provided. The model and simulation design steps in the simulation research, and the verification and validation steps taken through the model are also addressed.

The qualitative aspect of this study also contributed to the validation of the model and simulations. Semi-structured interviews were conducted with key informants after the quantitative step. The interviews aimed to generate the 'why', 'how', and 'what else' in the context of the quantitative findings. The interviews generated rich context-specific information on wholesale and EAPP markets, providing a deeper understanding of the quantitative results.

The population and sample of the research are then described for both quantitative and qualitative aspects. The quantitative part focused on selecting sample countries from the EAPP to run the simulations, whereas the qualitative part focused on sampling key informants who responded to the assumptions and results of the quantitative part through semi-structured interviews. The sampling methods used for both aspects of this research are described, and a discussion of the sample size and power analysis concludes this subsection.

The instrumentation of the research tools is then described. The AMIRIS model is described as the main tool of the research and the quantitative part. The version of the model used in the simulation, further descriptions of the modules, input and output files, and agents considered in the model are provided. The interactions of the agents in the simulation process were also explained to understand the workings of the model. The semi-structured questionnaire applied in the qualitative part was described, including informed consent forms and presentations of results from the quantitative part that were presented to key informants before the qualitative interview.

The next subsection provides descriptions of the operational definitions of the study variables. The independent variable is the penetration of VRE in the EAPP grid, whereas the dependent variables are the electricity pricing and dispatch levels of power plants. The definitions of these two main research variables are provided in detail. This study also identifies the control, moderating, and mediating variables that affect or influence the interactions between the dependent and independent variables and describes the influence of each.

The study procedure and ethical considerations are described below. These sections describe when the research was approved by the ethics committee and the ethical matters

related to the modelling software in the quantitative process. The procedures applied in the quantitative phase are then described, from the collection of input data to the execution of simulations. The structure of undertaking the research and caring for ethics in the qualitative phase is also described, including details on how the modelling and simulation were performed and the process of the semi-structured interviews.

The penultimate subsection of this chapter describes the data collection and analysis processes. It describes the data requirements for inputting the simulation model and the manner in which the data were acquired, including power plant data and several time series, such as demand, solar, hydropower, bioenergy, and wind resources, as well as natural gas, HFO, and CO₂ pricing levels. The coding applied to the countries and power plant data is also described. The outputs of the simulations, steps, and software used in their analysis are also described. The process of interviewing the key informants and how the data were analysed and grouped into themes is then described.

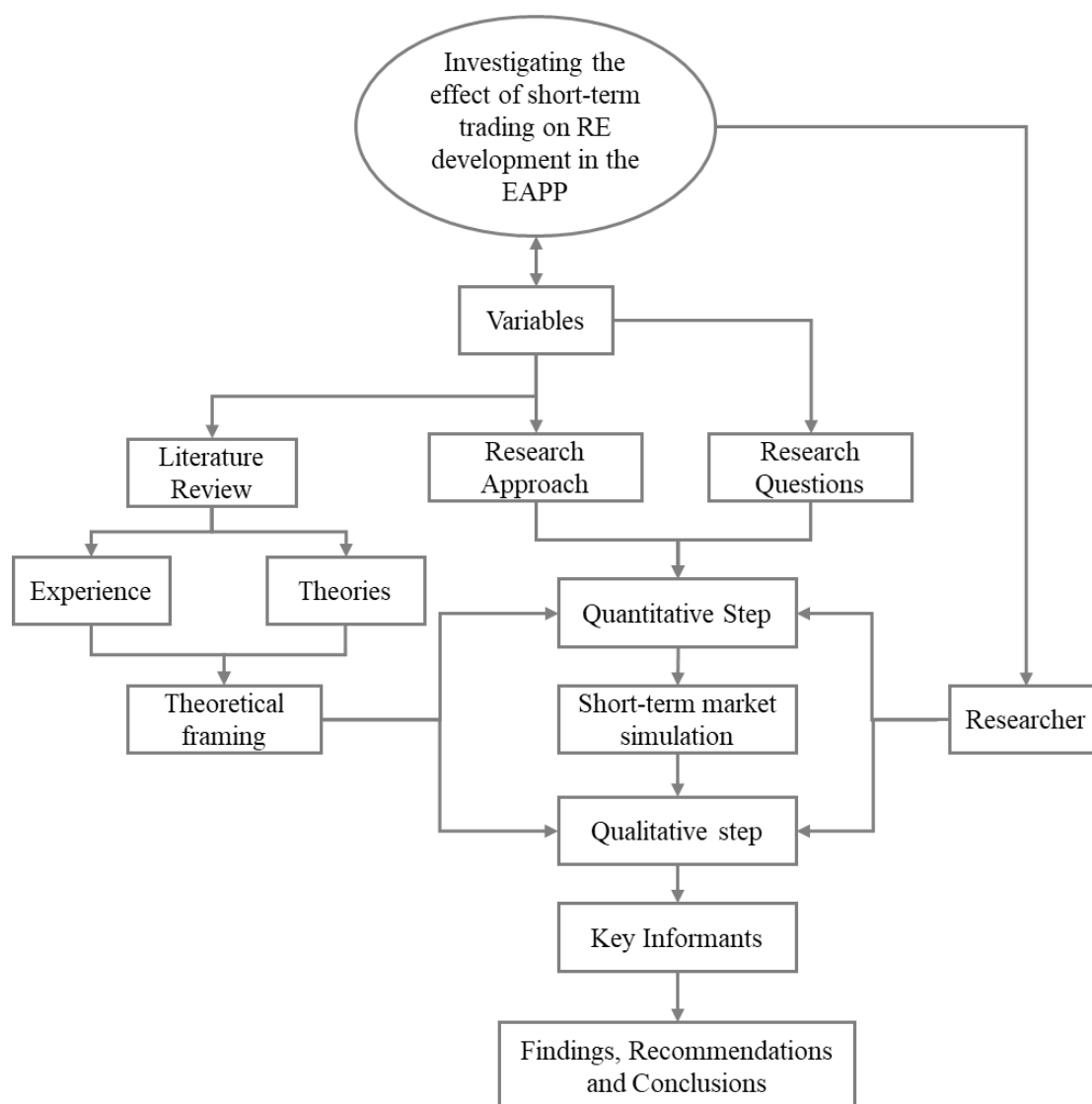
This chapter concludes with a summary of the methodologies employed in this study.

CHAPTER 3.2: RESEARCH APPROACH AND DESIGN

3.2.1. Introduction

The research structure for this study is shown in **Figure 3-1**. The research approach chosen for this study was a mixed-methods approach with a sequential explanatory design (Othman et al., 2020; Toyon, 2021).

Figure 3-1
Research Structure



The research approach was chosen because the electricity market being modelled does not exist, implying that the quantitative findings generated from the simulation would be synthetic and assumptions driven. A pure qualitative simulation would only yield opinions of experts without any system-level data. The research approach resolves this by applying agent-based modelling to generate quantitative findings on pricing, dispatch and VRE penetration. The qualitative phase contextualises, validates and extends these findings. The approach also allows for methodological triangulation at design, methods and interpretation levels. This allows convergence and divergence of qualitative and quantitative findings to make the research richer (Dossett et al., 2020; Feters et al., 2013).

The research undertook a quantitative research process through simulation, followed by a qualitative process to explain, query, and contextualise the quantitative findings using key informant interviews guided by a semi-structured questionnaire. The conceptual framework of this study is illustrated in **Figure 2-1**.

An explanatory sequential design was undertaken, beginning with a quantitative simulation to generate system-level insights into the dynamics of the Eastern Africa Power Pool wholesale market. These insights and patterns are non-intuitive and cannot be empirically observed. The simulation provides system-level findings that direct and focus on qualitative analytics. This is especially true because the EAPP wholesale market is not yet active. The qualitative step then develops in an explanatory way, with key informant interviews providing context, further interpretation, and analysis of the findings. This integration of methods was intended to lead to a greater understanding of the topic (McCrudden & McTigue, 2019). A purely quantitative approach would not ground the

research in the context, whereas a purely qualitative approach would result in general broad feedback void of the system-level nuances that the simulation provides.

Epistemologically, the quantitative approach through simulation attempted to model the EAPP wholesale market and explain its workings under high VRE in a data-driven, replicable model. The model and simulation results are synthetic, as they are based on a model built on assumptions and not reality. This allows for the modelling of complex systems but may also lead to overlooking the nuances (Beese et al., 2019). The qualitative process then aimed to gather information and understand subjective experiences localised to the EAPP from expert perspectives. This feedback from key informants further explains why phenomena are observed and contradicts based on experience. While this offered deeper insights, it also exposed the research to informant bias (Pahwa et al., 2023).

This study employed methodological triangulation through complementarity- and discrepancy-driven analyses. The simulation results and key informant interviews were treated as different explanations or evidence of the effects of VREs on the EAPP market. The integration of the two approaches was viewed at three levels: study design, methods, and interpretation and reporting, which is consistent with the framework in the literature (Fetters et al., 2013). This framework allows for the generality, specificity, and pragmatism required to study an emerging wholesale electricity market. This contrasts with the focus on the rationale or justification for using mixed methods (Creamer, 2018).

This study integrates these two methods through an explanatory process. The method employed a building approach, with the results of the quantitative process informing the qualitative key informant interviews. However, the merging approach was also employed to gain additional insights from the key informants that were not covered by the simulation. At

the interpretation and reporting level, a narrative approach was adopted with a description of the quantitative and qualitative findings by theme (Guetterman et al., 2015), highlighting points of alignment and departure.

This study thus examined the Eastern African electricity market by adapting a computer-based model to simulate how a short-term wholesale market would affect trading outcomes for a high penetration of VRE power plants. The research ultimately delivers a qualitative judgment informed by the model results and key informant interviews. The research concludes on the main research questions based on collecting and analysing non-numeric data and drawing qualitative conclusions from the numeric data of the model, aiming to understand whether a wholesale market in Eastern Africa would encourage more VRE.

An expert survey was conducted after the model was built based on quantitative conclusions from the simulation process. The simulation process added rich statistical information to enrich the researcher's and key informants' interpretations of the problem and their qualitative perspectives. The goal of this research was not to provide statistical information, but rather to provide more analytical and detailed qualitative insights into a wholesale market for Eastern Africa and the effects of onboarding more VRE capacity. This has resulted in recommendations for policy interventions and proposals for future areas of research.

The research was subjected to expert (key informant) opinion, and the conclusions on the ability of the research to answer the research questions depended on the specific interpretation of the researcher and the experts. To quantitatively study the electricity market in Eastern Africa, a software-based model of the market was adapted, and simulations were run by applying a simulation research design. Simulation research design allows the modelling

of complex systems, as it allows researchers to incorporate the inherent complexities of systems and test ‘what if’ scenarios (Dooley, 2002). Simulations allow the study of complex systems, such as an electricity market, where a survey or physical experiment may not be possible or practical. Software simulations are the best solution for approximating the actual situation in the EAPP market.

Simulation models serve as laboratories to test aspects such as regulatory structures before they are applied to real systems (North, Conzelmann, et al., 2002). Conducting experiments on actual electricity market infrastructures is difficult and impractical. For this research, a model of the EAPP electricity market was built by adapting the AMIRIS model. Notably, the market does not exist and is only in the mid-stages of being contemplated, with an expectation of a day-ahead market going live in the second quarter of 2025. The model provides a testbed for researchers to run simulations of various scenarios and make observations of what can be expected in the real market (North, Macal, et al., 2002). This is described as ‘observations by moving forward into the future’ (Dooley, 2002). Other research methods look backward to understand what happened. Simulations can be used for prediction, performance, training, entertainment, education, proof, and theory discovery. These aspects could be useful for various stakeholders in the Eastern African electricity sector.

For this research, simulation as an experimental design was used to run tests on the model of the Eastern African power pool and to address the research questions. The simulation approach allowed the modelling of a short-term electricity market in the EAPP, enabling the study of the effect of increased varying renewable energy penetration on the grid.

3.2.2. Simulation Research Design

Three approaches to simulation research design have been identified: discrete event simulation, system dynamics simulation, and agent-based simulation (Dooley, 2002). Discrete event simulation is best used when the system can be characterised by variables and corresponding states, and there is a rule-oriented stochastic relationship between events and the value of variables. The system dynamics approach is suitable for situations in which multiple variables have related rates of change, with one changing because of a change in the other. System dynamics models simulate causal effects within a system (Teufel et al., 2013). In contrast, agent-based simulation focuses on modelling a system as a collection of interacting agents via a schema. Agents change their schema by learning and adapting during their interactions with other agents. In this sense, agent-based models focus on the participants in the system as discrete entities, whereas system dynamics models focus on variables and events. This makes agent-based models relevant to wholesale deregulated markets (Shinde & Amelin, 2019).

3.2.3. Agent-Based Modelling and Simulation

This study followed the agent-based modelling approach because it best represents the interactions in a wholesale electricity market with different agents learning after every trade (Ringler et al., 2016). Agent-based simulation models are best suited to model the complex strategies used by participants in electricity markets (Ferreira dos Santos & Tomé Saraiva, 2021). Simulation approaches that apply mathematical optimisation, system dynamics, and equilibrium models do not account for the behaviour of agents in electricity markets (Fraunholz et al., 2021). Agent behaviour affects market outcomes in wholesale markets. In addition, standard game-theoretic techniques cannot fully model these interactions. Agent-

based models consist of agents and a framework for simulating their decisions. An agent is the decision-making unit represented in software and is autonomous, social, reactive, and proactive. Thus, they generate market outcomes (price, demand, and supply) endogenously over an hour, in contrast to the exogenous generation of market outcomes in other approaches.

Agent-based modelling and simulation (ABMS) is designed to model an electric power system and construct an economy with various agents and institutional frameworks. These include their learning behaviour, decision rules, and relationships with other agents. These agents then make autonomous decisions that lead to the evolution of the market without the intervention of the modeller (Ringler et al., 2016). The actions of the agents are based on their initial state, decision rules, and decisions made in interactions with other agents, including the effects of learning. These agents bid for supply and demand, with the resultant marginal price determining trade. Previous researchers have used ABMS to model and simulate electricity markets (Wehinger et al., 2013).

Agent-based models for electricity markets include both economic (producers, consumers, and their intermediaries), and institutional (weather, regulator, and market operators) agents (Ringler et al., 2016). The behaviour of agents can be based on simple rules or complex multicriteria optimisation models. This approach also allows the analysis of electricity markets in aspects such as asymmetric information, learning, externalities, strategic interactions, and uncertainty. These deviate from the notion of a perfectly competitive market and better mimic real-world markets. The physical aspects of the electricity market, such as transmission and distribution networks, as well as the economic, informational, and social aspects, can be considered in agent-based modelling approaches. Agents face different situations when making decisions.

The agents foreseen in the Eastern African electricity market and their interests are summarised in **Table 3-1**, as derived from electric power market agent descriptions (C. Macal et al., 2015). These agents have different attributes, objectives, and behaviours that help frame the key aspects of the model. Their perspectives influence the strategies they employ in the market.

A perfectly representative electric grid model requires the modelling of power plants, load centres, transmission lines, and node-level demand and supply. The approach of modelling the electric grid as a direct current optimal power flow (DC-OPF) model is typically used to reduce the complexity and computational requirements of the model (C. Macal et al., 2015). Alternating current models introduce complexities when combined with economic (agent) models. The DC-OPF balances demand and supply with respect to transmission link capacities and is commonly used in real-world electricity markets for scheduling and market clearing (C. Macal et al., 2015). Agent-based models in electricity assume that power flow in the grid is not an issue but rather focus on the behaviour of agents in optimal flow conditions.

Various software tools are used to develop and run agent-based models and simulations. These include the AMIRIS, PowerACE, EMLab, EMCAS, and AMES models (Allan, 2010; Ferreira dos Santos & Tomé Saraiva, 2021; Fraunholz et al., 2021; Li & Tesfatsion, 2009). This study adapted the Java-based AMIRIS model described in Section 3.4.1, which was developed by the German Aerospace Agency for the Eastern African market (Klein, 2020; Reeg et al., 2020; Schimeczek et al., 2023). The model is open source, receives regular updates, and has an active developer community on GitHub (DLR, 2026). Additionally, the development team

based in Germany responded to queries. The AMES model was also considered; however, it was found to have an inactive developer community and fewer recent updates.

ABM research is advancing into machine learning and the application of artificial intelligence to model the behaviour and interactions of agents in an electricity market (Gokce & Kayakutlu, 2025; Kell, Stephen McGough, et al., 2022). The most prominent use of these new approaches is price forecasting (Fraunholz et al., 2021). Machine learning and artificial intelligence approaches are being incorporated to optimise agent behaviour targeted at bidding strategies, demand, and pricing-level prediction based on past data (Kell, McGough, et al., 2022). Machine learning has been proposed as a means to improve the decision-making of agents in ABMs by applying reinforcement learning, decision trees, and Bayesian networks (Ale Ebrahim Dehkordi et al., 2023; Platas-López et al., 2025).

Table 3-1*Anticipated electric power market agents for the Eastern African Power Pool*

Agent	Attributes	Objectives	Behaviours
Generating Company Agent (Genco)	Own power plants	Maximise profits	<i>Dispatch strategy</i> : Decide how and when to operate plant <i>Bidding Strategy</i> : Determines the offer price and quantity of generation to be sold to the market. Submit a day-ahead price
Independent System Operator Agent (ISO)	Operates the electric system	Balance demand and supply Maximise social welfare	<i>Planning function</i> : Forecast day-ahead weather, demand and supply and ensures information is available to all parties <i>Pool Market Function</i> : Operates the pool market for energy and ancillary services. Administer price setting market rules e.g., Locational Marginal Pricing <i>Dispatching Function</i> : Dispatch generators to balance demand in real time. Maintain system security <i>Settlement Function</i> : Apply settlement rules to discern payments and receipts expected from Gencos, Transcos, and Discos
Transmission Company Agent (Transco)	Owns and operates transmission assets	Supply power. Minimise transmission costs	Transmit electric energy from generation plants to distribution networks
Demand Agent (Utility) (Disco)	Aggregates customer agents Aggregates annual and hourly load profiles Operate load nodes	Maximise profits	Create aggregate load from customer demand Submit load forecast and bids to the ISO
Consumer Agent (Cust)	Load profile (Daily and annual)	Satisfy end-user power needs. Minimize costs	Establish electricity load in response to customer service needs and electric power prices

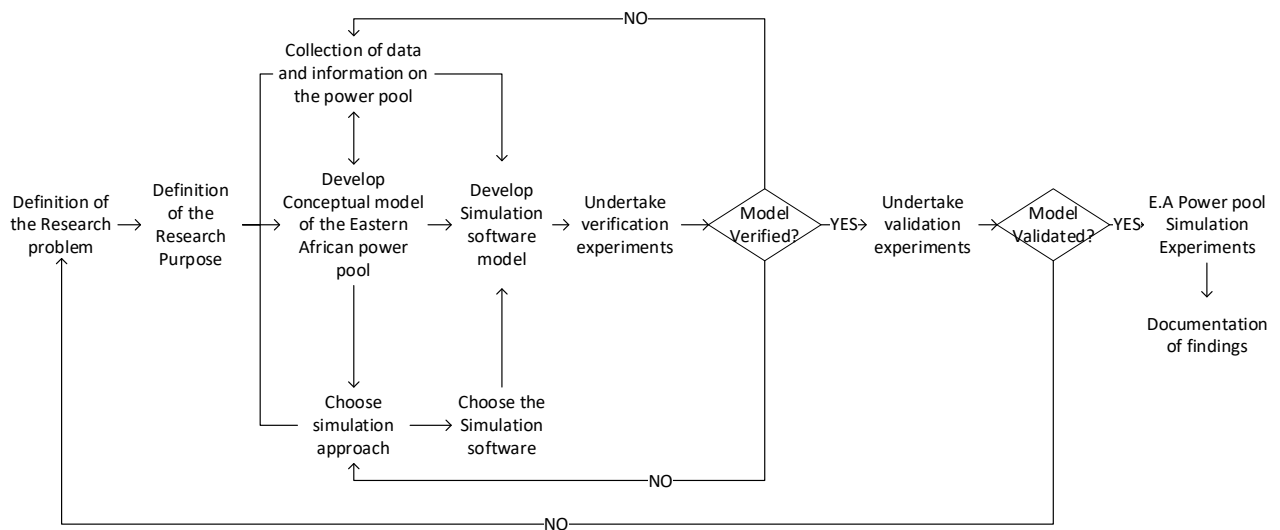
Note. Adapted from (C. Macal et al., 2015)

3.2.4. Description of Model and Simulation Design Steps

The modelling and simulation processes are summarised in **Figure 3-2** (Yin & McKay, 2018). Building on the research problem and purpose, data and information relevant to modelling the EAPP were collected. This included data on generation plants, transmission line capacities, generation tariffs, and the rules of operation of electric grids in Eastern Africa. These data were essential for defining the conceptual and simulation models of the power pool. A conceptual model of the anticipated physical and market interconnections in the Eastern Africa Power Pool was developed. This involved using the data collected in coordination with the research purpose to adapt the AMIRIS model to a conceptual model.

Figure 3-2

The modelling process followed in the research



Note. Adapted from (Yin & McKay, 2018)

The modelling and simulation method applied is the agent-based approach, which is at the core of the AMIRIS model. This was adjudged to be sufficient to respond to the defined research problem and answer research question 2. AMIRIS was selected based on its

availability and adaptability (Yin & McKay, 2018). AMIRIS was also preferred because it is open-source software that can be freely downloaded and has a bias in modelling market conditions of electricity markets with renewable energy penetration.

The model of the Eastern Africa power pool was developed in a software environment, and model verification experiments were conducted until the model was verified to be representative of the expected physical and market operations of the Eastern Africa power pool. Verification approaches and criteria were developed in advance to guide the verification process. This included running a scenario in the Kenyan electricity market for 2023 for which data enabling triangulation were available from the Kenyan regulator. The goal was to verify the reliability of the model outputs for the given inputs and their consistency with expectations or similar real-world scenarios.

Validation experiments were conducted to verify the accuracy of the model in representing and addressing the research problem in relation to the purpose of the research, as described below. The validation process quantifies the accuracy of the model by comparing the simulation results with real-world operational outcomes (Yin & McKay, 2018). The necessary iterations of the model code were performed to improve its accuracy in the context of the EAPP.

Simulations of the inputs were designed to mimic the expected operations of the EAPP. The validated model was then run for two simulation experiments under different VRE penetration conditions in an electricity network. The anticipated real-world operations of the EAPP were simulated for 2025. Varying levels of penetration of VRE sources in the power pool were investigated, assuming day-ahead short-term market implementation.

3.2.5. Model Verification and Validation

Model verification examines the accuracy of the mathematical relationships between the parameters in the model, whereas validation examines how well the model represents real-world situations (Yin & McKay, 2018). Model verification can be performed using social science approaches because of agent interactions, which are a social phenomenon (Ringler et al., 2016).

A Kenyan scenario for 2023 was run on the model and its results triangulated with the official statistics of the Kenyan regulator EPRA for the same year. This involved comparing the pricing and dispatch of various power plants in the Kenyan grid. This step allowed the researcher to confirm that the model performed similarly to the actual situation on the Kenyan grid. This allowed the verification of the process and findings of the model and simulation. The model was thus validated and cleared for application to the case of the five sampled countries for 2025.

The conceptual model was verified against the research problem to determine whether it sufficiently addressed the problem being researched. The simulation model was also verified against the conceptual model to ensure that it represented the concept as defined by the research problem. Throughout the entire modelling and simulation process, the validity of the data used was checked, as the quality of the data used is an important aspect of the model's verifiability and validity (Yin & McKay, 2018). Simulations were run on the model, and the results of how the electricity market behaves with varying levels of renewable energy were obtained, analysed, and used to draw conclusions on whether short-term markets can encourage the penetration of renewable energy in the EAPP. These findings, assumptions, and data were validated via semi-structured interviews with sampled experts in the region.

3.2.6. Result Validation via Semi-Structured Interview

Semi-structured face-to-face or video conference meetings were conducted with key stakeholders in electricity markets in Eastern Africa to verify the assumptions and findings of the modelling process. The sampling of the views of stakeholders and data from countries in Eastern Africa followed purposive sampling, targeting participants in the five sampled countries. An estimated population of 500 expert stakeholders was targeted. Methods of questioning that promote truthful responses (Patton & Cochran, 2002) were used. A list of key thematic areas and topics was prepared, and prompts were developed to encourage respondents to address certain aspects should they not arise naturally (Elmusharaf, 2012; Patton & Cochran, 2002).

Qualitative analysis was applied to interview findings and documentation to identify common patterns and themes related to short-term trading in power pools and the levels of penetration of renewable energy. Convergence and divergence points and recurring themes in the interviews were sought (Pope et al., 2000). Unexpected themes that arose from the review and interview responses were explored. The aim of this process was to verify whether the model and its findings aligned with expectations in a real-world scenario.

CHAPTER 3.3: POPULATION AND SAMPLE OF THE RESEARCH

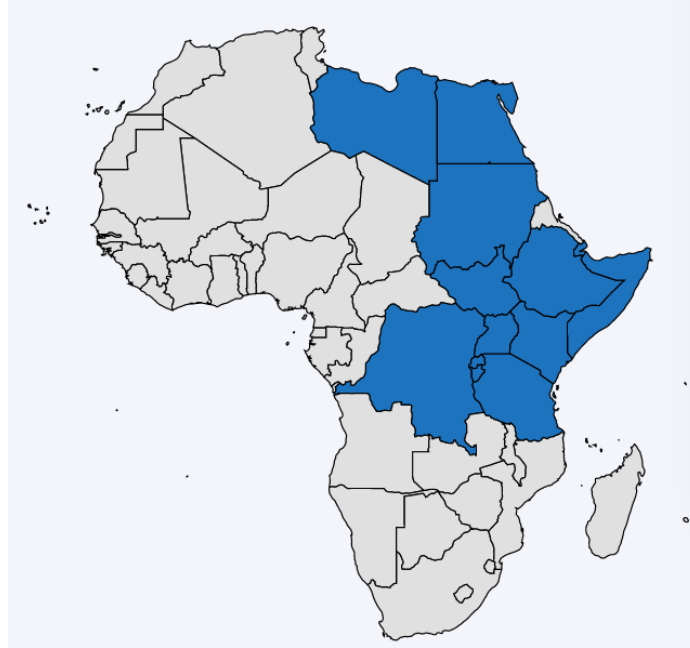
3.3.1. Introduction

This study examined the 13 countries that comprise the EAPP, namely, Kenya, Uganda, Tanzania, Burundi, Sudan, Somalia, Libya, Egypt, Rwanda, Ethiopia, the DRC, Djibouti, and South Sudan (**Figure 3-3**). Eritrea is in the region but was not a member as of 2025. The EAPP is a specialised agency for electrical power in the Common Market for Eastern and Southern Africa (COMESA). The electricity grids of the 13 countries with varying levels of interconnectivity formed the study population. These countries already have a level of grid interconnectivity or have interconnections that are under construction or planned with known technical design parameters. The research narrowed down to five countries in the pool as the focus of the study: Tanzania, Uganda, Kenya, Rwanda, and Ethiopia.

This study undertook a simulation and key informant interview process in a mixed methods research design. The mixed-methods approach followed a sequential explanatory design (Toyon, 2021). The quantitative component was undertaken using a simulation model for the EAPP. Subsequently, key informant interviews were conducted to gain further insight into the findings of the simulation and its assumptions. Thus, sampling was performed separately for the quantitative and qualitative parts of the research and is described in the following section.

Figure 3-3

Map of Africa showing the countries of the Eastern African Power Pool



3.3.2. Sampling in the Quantitative Aspects of the Research

For the quantitative part of the research, a population of 13 EAPP countries was considered, and a sample of five countries was chosen for the analysis. Purposive sampling involves the deliberate selection of participants based on their qualities.

In this case, these five countries had interconnections that already existed at the time of the research, and all were preparing long-term power plan reports that could be accessed and assessed in the context of the research. The use of purposive sampling in the quantitative step is not in line with random sampling for such a step, as recommended in literature (Creswell, 2022). Random sampling would not have worked given the need to ensure a continuous flow of electricity across the sampled grids in this research, mimicking a functional grid with electricity flowing across countries. It was necessary to ensure that the sampled countries were

in a contiguous block within the pool. Random sampling may have led to the selection of five countries that are not physically interconnected to each other and, thus, not capable of directly trading power without a go-between country that would not be selected in a random sample.

Purposive sampling is a non-probabilistic sampling technique. The goal of such sampling is to gain as much information from the sampled portion of the population and not to generalise findings to the wider population. This sample allowed for an in-depth analysis of an interconnected portion of the EAPP.

Researchers choose samples based on the judgment of specific criteria that determine who is knowledgeable and willing to provide the information required. This study applied a mixture of expert and homogeneous sampling (Etikan, 2016) to select the countries to be modelled.

This research focused on five closely connected grids in East Africa: Kenya, Tanzania, Uganda, Ethiopia, and Rwanda. These five grids comprise more directly interconnected grids of similar sizes within the EAPP region. The power grids of Kenya, Uganda, Tanzania, and Rwanda are one synchronous grid, and Ethiopia, although not synchronised to these grids, has an HVDC connection to Kenya. The five grids have direct interconnections, allowing power to flow across national boundaries without flowing through any of the excluded eight countries. This made the five sampled countries ideal for running a simulation.

The grids of Somalia and South Sudan were excluded because of the lack of interconnection to the pool and demand for information. Egypt, Sudan, and Libya were excluded because of vast differences in socioeconomic characteristics, including language, which would make research difficult in these countries. Burundi and Djibouti were excluded due to the insignificance of the grids in the pool and minimal interconnectedness with their

neighbours. Eastern Congo (DRC) is excluded as it has minimal interconnection with Eastern Africa. The exclusion of some of the larger grids from the study with isolated interconnectedness, that is, Egypt, Libya, and Sudan, was also done to limit the complexity of the study and manage computing capacity. The selection of the five countries in this study was deemed sufficient to obtain a contiguous sample of the EAPP grid and answer the research questions. The interconnection capacities in the EAPP are shown in **Figure 3-4** and **Table 3-2**.

Figure 3-4

A summary of interconnection capacities in the EAPP



Note. Adapted from EAPP (2024). Line transfer capacities are labelled

The entire population of power plants in the five countries was used in the simulation process. This was essential to ensure that the simulation was representative of the situation that would be obtained on the grid in 2025. These power plants were grouped by technology and clustered per country for anonymity. The use of the full generation fleet was deemed convenient for framing the model for the necessary simulations.

Table 3-2

Interconnectedness of EAPP Countries projected to 2025

Country	Installed Capacity (2025) (MW)	EAPP Membership [Y/N]	Sampled [Y/N]	Interconnection Status with EAPP Countries (2025)	2025 Transmission Interconnection Capacity (MW)
Egypt		Yes	No	LB: SU	240: 300
Libya		Yes	No	EG	240
Ethiopia	10576	Yes	Yes	KE: DJ: SU	2000: 180: 1200
Eritrea		No	No		
Sudan		Yes	No	ET: EG: SSU	1200: 80: 200
South Sudan		Yes	No	SU	200
Uganda	3133	Yes	Yes	DRC: RW: TZ: KE	140: 347: 279: 300
Tanzania	5000	Yes	Yes	UG: KE: ZM	279: 1500: 1500
Rwanda	400	Yes	Yes	2 x UG: TZ: BR: 4 x DRC	357: 27: 27: 104
Burundi	100	Yes	No	DRC: RW	53: 27
Kenya	3610	Yes	Yes	2 x UG: ET: TZ	370: 2000: 1500
Somalia		Yes	No		
Djibouti		Yes	No	ET	184
Congo (DRC)		Yes	No	4 x RW: BR: UG	104: 53: 140

Note. Data sourced from (EAPP, 2023; ERA Uganda, 2016; MoE, 2022; MoE Tanzania, 2020; Nord Pool Ricardo, 2021; Rwanda Energy Group, 2022; USAID Power Africa, 2021)

3.3.3. Sampling in the Qualitative Aspects of the Research

For the qualitative step, purposive sampling was used to select the key informants for interviews. The interviews aimed to validate the findings and assumptions of the model and

simulation by applying semi-structured interviews with various experts in the region's electricity sector. The population of experts in the region capable of responding to the research findings in the quantitative steps was estimated to be 500. This comprised senior-level managerial staff in the power sectors of the 13 countries engaged in activities related to the EAPP. These included energy sector regulators, transmission and distribution companies, policy-making bodies, and power generators.

For the five countries under investigation, a total sample size of 20 was chosen to be targeted for the semi-structured interviews to achieve saturation. This was anticipated to include approximately 200 individuals in the population. The participants were chosen from the EAPP secretariat, the Energy Regulators Association of East Africa (EREA), energy regulators in Uganda, Kenya, Tanzania, Ethiopia, and Rwanda, and the utilities in these countries.

The participants were recruited through emailed requests for virtual face-to-face interviews through Zoom and, where available, physical meetings. The email request included a semi-structured questionnaire and an informed consent form. Twenty were identified from regular participants in the EAPP discussions and by referral by previously identified participants and a review of the personnel of key regional energy institutions, with the aim of ensuring the representation of the five countries in the sample. Twenty were approached with requests for semi-structured interviews, and eleven were interviewed before saturation was reached. The sampling is summarised in **Table 3-3**.

Table 3-3*Sampling for the quantitative and qualitative approach*

Sampling	Quantitative	Qualitative
Population	13 countries	500 (managerial level)
Estimated Population (5 countries)		200
Sample	5 countries	20
Actual	5 countries	11
Sampling method	Purposive	Purposive

The sample size was chosen as this number was considered sufficient to lead to saturation of the feedback, given the highly specialised nature of the findings to be brought to the key informants. Information from the informants was expected to be repetitive beyond this sample size. This sample size would also allow for the breadth and depth of the feedback to be achieved (Creswell, 2022). Feedback was required to provide detailed explanations of the quantitative findings from the simulations.

Saturation was achieved after 11 interviews with key informants. These key informants formed a homogenous group of experienced economists and engineers active in the electricity sector and were presented with a specific set of findings and assumptions from the simulation. This led to saturation, as observed in similarly populated studies (M. Hennink & Kaiser, 2022; Yang et al., 2022).

The key informants had 8–51 years of experience. The average years of experience in the electricity sector for the informants was 23.2 years. The key informants were all male, aged between 32 and 75 years, as shown in **Table 3-4**.

. The years of experience in the electricity sector of the various countries distributed among the key informants was a mark of confidence in the quality of their responses to the

simulation results and assumptions. Additionally, five of the 11 informants held doctorate-level qualifications in the electricity sector on topics related to the area of study. They were all aware of and had interacted with the EAPP at different levels of advancement. This further increased confidence in the quality of the responses. The informants were assigned unique codes to obscure their identity in addition to the demographic data collected.

Table 3-4

Summary of key informants' distribution in age and years of experience

Age band (Years)	Number		Years of experience (Years)	Number
30 to 39	3		0 to 19	5
40 to 49	3		20 to 39	5
50 and over	5		50 and over	1

The interviewed informants were managerial-level employees of regulators, generators, and transmission and distribution companies in the private and public sectors. The key informants were representatives from Kenya, Uganda, Tanzania, and Ethiopia. Although none of the key informants were from Rwanda, they had a good understanding of the prevailing situation in all five countries concerning the EAPP. This lack of informants from Rwanda did not affect the findings and feedback of the key informants, as Rwanda has a much smaller grid than the other countries with the smallest interconnection capacity to the other four countries. Feedback from the 11 key informants was deemed sufficient to inform the research.

The interviewed informants did not include female respondents as there were none identified within the pool of key informants. This is a weakness in representativeness; however, it was not judged to lead to significant distortion of the study's responses.

3.3.4. Sample Size and Power Analysis

The sample sizes for the explanatory sequential mixed methods study were chosen to achieve the study goals. Starting with the quantitative aspects, the five countries chosen had the most direct interconnectedness and availability of data on generation plans and demand. This criterion allowed for the simulation to be performed without having to build in assumptions for power flows in an intervening country grid that was not included in the sample. The countries chosen in the sample had direct physical boundaries with each other and direct transmission network links, allowing for effective modelling and simulation. The sampled countries displayed similar power, as there were no restrictions on transmission capacity. However, it could be argued that Ethiopia would exhibit more power because it has a larger installed capacity, representing 52.3% in the base case and 58.8% of the total installed power. However, this is also true in practice, implying that the sample's power balance represents the realities of the EAPP.

The qualitative aspect of the research relied on achieving saturation. In this explanatory sequential study, the quantitative phase preceded the qualitative phase. The key informants were presented with quantitative findings, and their feedback was noted. Saturation was achieved with a sample size of 11 from an initial projection of 20 interviews.

The power analysis in this study anticipated balancing the quantitative and qualitative aspects of the study. The sampling selection for the quantitative part, as described above, was chosen to ensure that the modelling is responsive to the situation in the EAPP in terms of interconnectedness and availability of data. This sampling allowed for the examination of the effect of higher VRE levels on the EAPP grid. The quantitative part was balanced off by the qualitative part as the key informants were used to comment and provide additional feedback

on the assumptions and results of the quantitative analysis (the model and simulation). This provided a good balance of intervention for the qualitative and quantitative aspects of the research findings. Throughout the qualitative study, thematic saturation was monitored in various aspects highlighted by the key informants. These included themes such as the assumptions of infinite transmission capacity, negative pricing, and the need to incorporate ancillary services into the simulation. The qualitative analysis provided more insight into the significant findings of the quantitative analysis. This ensured a good interaction between the two approaches.

CHAPTER 3.4: INSTRUMENTATION OF RESEARCH TOOLS AND DATA COLLECTION

This study investigated the use of short-term trading to encourage VRE in the Eastern African electricity market. This study investigated the effects of VRE penetration in a short-term electricity market to enable the region to learn about short-term markets and the issues to be considered with higher levels of VRE. The research is based on the strength of the second research question, which sought to investigate how a wholesale electricity market in Eastern Africa would be affected by the introduction of more VRE.

This section provides details of the research tools used to conduct the study. This study relied on two main tools to respond to the problem statement and research questions. These were a computer-based model, AMIRIS, for the quantitative aspect, and semi-structured questionnaires for the qualitative part. This is described in detail in the following section.

3.4.1. The AMIRIS Model

This simulation research utilised a software model as the main tool and applied a questionnaire to validate the model and its findings. This section presents the model with an introduction, model adaptations, assumptions made, input data sources, validation checks, and scenario design.

3.4.1.1.INTRODUCTION

In this study, the **Agent-based Market** model for the **Investigation of Renewable and Integrated energy Systems (AMIRIS)** version 2.0.0-alpha.33 was used. This model was developed and maintained by the German Aerospace Center (DLR). It is an open-source tool that runs on the Java platform and is based on the open **Framework for distributed Agent-based**

Modelling of Energy systems (FAME), and is available on Gitlab (Schimeczek et al., 2023). AMIRIS is an agent-based model used to simulate electricity markets.

AMIRIS focuses on the business-oriented decisions of actors in wholesale electricity systems. These agents have complex decision-making strategies driven by market price assessments and generation forecasts (Nitsch et al., 2021). Agent decisions are influenced by marginal prices, support instruments such as feed-in tariffs, market power, and information availability (Deissenroth et al., 2017).

The AMIRIS model simulates the operation and trading of power plants in a market zone with a resolution of 1 h. It models market behaviour under uncertainty. The model was designed for high processing speeds of less than 1 min per run. The inputs and outputs of the model are listed in **Table 3-5**. The overall structure of the interactions between agents and the flow of money, energy, and information in the market is depicted in **Figure 3-5**.

Table 3-5

Inputs and outputs of the AMIRIS model

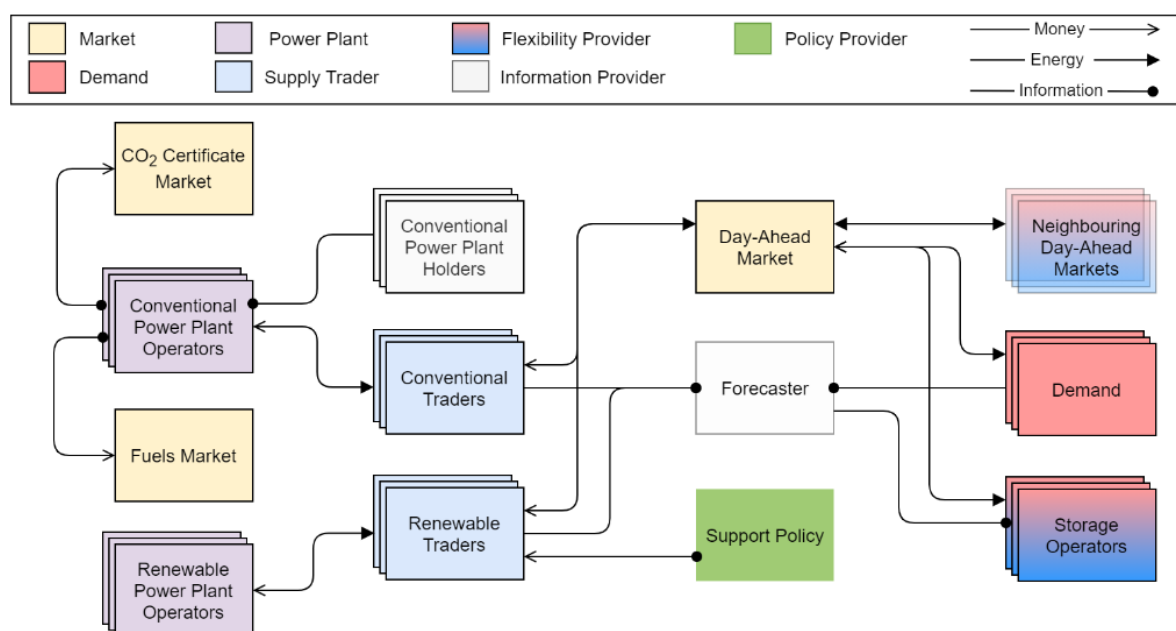
Model Inputs	Model Outputs
Power plant details (type, capacity etc)	Electricity prices (annual hourly timeseries)
Annual hourly timeseries of demand in the market	Plant dispatch (Full Load Hours)
Efficiencies of the powerplants	Market values
Availabilities	System costs
Fuel prices	Costs of support instruments
CO2 Prices	CO2 emissions
RES-E Feed in potential	

The model has agents with interactions and actions, as described in **Figure 3-5** and detailed in **Table 3-6**. It allows the study of different political framework conditions on the behaviour and profitability of energy market actors, considering different market paths. The

model allows for the evaluation of the influence of actors and socioeconomic decisions on energy markets. The model allows for the direct entry of multiple parameters via a notepad directly into the ‘*scenario.yaml*’ and ‘*contract.yaml*’ files, allowing for reproducibility, transparency, and accuracy. The input files are provided in .csv timeseries format and the outputs also provided in .csv format.(Klein, 2020; Reeg et al., 2020).

Figure 3-5

Overview of AMIRIS Agents



Note. Adapted from the AMIRIS Website (DLR, 2024)

The various data files applied in modelling the EAPP in the base and high RE scenarios are described in **Table 3-7**. The YAML files are presented in Appendices 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, and 20. These files contain unique data and code for the EAPP scenario used in this study. The schema YAML file is standard for each AMIRIS release and was not edited to run the simulation. Various .csv files in hourly and annual time-series formats were

necessary to run the model. The model has the capability to allow the study of different political framework conditions on the behaviour and profitability of energy market actors, considering different market paths. The model allows for the evaluation of the influence of actors and socioeconomic decisions on energy markets. The model allows for the direct entry of multiple parameters via a notepad directly into the '*scenario.yaml*' and '*contract.yaml*' files, allowing for reproducibility, transparency, and accuracy. The input files are provided in '*.csv*' timeseries format and the outputs are also provided in '*.csv*' format (Klein, 2020; Reeg et al., 2020).

Table 3-6*Description of Agents' interactions and actions in AMIRIS*

Agent	Interaction	Actions
• Renewable Power Plant Operator • Conventional Power Plant Operator	• Calculates marginal cost • Dispatches power plants	• Calculates power potential • Calculates marginal cost of generation • Sends marginal cost to trader • Receives assignment • Dispatches the power plant
• Renewable trader • Conventional trader	• Creates Bids • Requests Support	• Receives the marginal costs • Checks support instrument • Derives the supply bid • Sends bids to exchange • Receives the award • Forwards power to the operator
Support Policy	• Calculates support tariffs • Provides support funding	• Registers clients • Tracks power prices • Tracks feed-in potentials • Calculates variable tariffs • Provides support
Demand Trader	•	• Creates demand bid • Sends bid to the exchange
Forecaster	• Calculates forecasted merit order	• Gets inflexible forecasted bids • Clears forecasted market • Sends forecasted clearing data
Information provider	•	• Creates forecasts
Energy Exchange (Day-ahead market)	• Market Clearing	• Receives bids • Clears the market • Sends awards
Storage operator	• Evaluate forecasts • Optimise Dispatch • Consider own impact on prices	• Gets forecasted clearing data • Optimizes bidding • Sends bids to exchange • Receives awards • Operates storage device
CO2 market	•	Define CO2 certificate prices
Fuels Market	•	Define the fuel prices
Neighbouring markets	• Can be integrated using market coupling • Can be emulated using demand/supply timeseries	

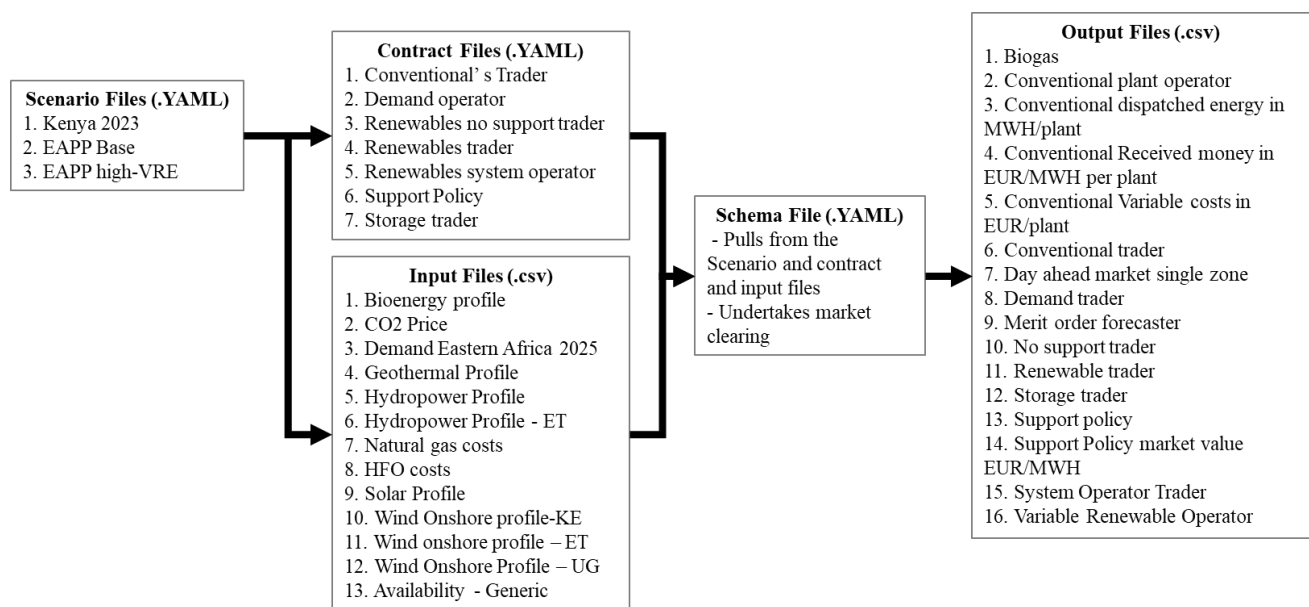
Table 3-7*Data files by type in the EAPP model*

<i>File Type</i>	Description	Files
<i>Input timeseries (.csv file)</i>	Requires timeseries files to allow for simulation	• Bioenergy profile • CO2 Price • Demand Eastern Africa 2025 • Geothermal Profile • Hydropower Profile • Hydropower Profile - ET • Natural gas costs • HFO costs • Solar Profile • Wind Onshore profile-KE • Wind onshore profile – ET • Wind Onshore Profile – UG • Availability - Generic
<i>Contract (.yaml file)</i>	Defines all contracts in the market	• Conventional • Demand • Renewable No Support • Renewables trader • Renewables System Operator • Storage • Support Policy
<i>Scenario (.yaml file)</i>	Define the scenarios of interest: It is the main configuration file for a simulation	• Base scenario 2025 • High Renewable Energy Scenario 2025 • Kenyan Scenario 2023
<i>Schema (.yaml file)</i>	Main engine calling agents and their files	• Schema file
<i>Output (.csv file)</i>	Provides time series outputs showing results of market clearing	• Biogas • Conventional plant operator • Conventional dispatched energy in MWH/plant • Conventional Received money in EUR/MWH per plant • Conventional Variable costs in EUR/plant • Conventional trader • Day ahead market single zone • Demand trader • Merit order forecaster • No support trader • Renewable trader • Storage trader • Support policy • Support Policy market value EUR/MWH • System Operator Trader • Variable Renewable Operator

The AMIRIS model has three main types of files used to adapt and run scenarios. These are the ‘*schema.yaml*’, ‘*scenario.yaml*’ and contract files. The contract files are ‘*conventionals.yaml*’, ‘*demand.yaml*’, ‘*supportPolicy.yaml*’, ‘*renewableTrader.yaml*’, ‘*renewables_noSupport.yaml*’, ‘*renewables_SystemOperator.yaml*’, and ‘*storage.yaml*’. The files are interconnected, as shown in **Figure 3-6**.

Figure 3-6

Process flow in AMIRIS



The YAML files are presented in Appendices 8, 9, 10, 11, 12, 13, 14, 15, and 16. These files contain unique data and coding for the EAPP scenario used in this study. The schema YAML file is standard for each AMIRIS release and was not edited to run the simulation. Various . CSV files in hourly and annual time-series formats are necessary to run the model.

AMIRIS bundles power plants with a certain technology into a class that is managed and operated by power plant operator agents. In this run, renewable and conventional power plant operators are considered. These are associated with trader agents that market the generation capacity on the exchange (day-ahead market) agent. This exchange agent also receives demand bids from demand traders. The exchange agent matches demand and supply bids using hourly marginal pricing and clears the market accordingly. The agent then sends awards to traders of various technologies, who instruct the power plant operators to run as per the award (Klein, 2020).

The traders for each power plant technology are programmed to mimic the bidding behaviour of that type of power plant in such a market. The support policy agent assesses the feed-in tariff potential and calculates the premium to be paid to RE traders, which is then incorporated into the bidding price of these traders. The value of the market premium in the last month is applied as the premium at bidding before the policy support agent issues a premium. AMIRIS dispatch was found to be consistent with the dispatch from an optimisation model if the model parameterisation is the same (Klein, 2020). This coupling has also been studied in another study (Torralba-Díaz et al., 2020).

3.4.1.2. Model Adaptations for the EAPP

The AMIRIS model includes a scenario file for the 2019 German electricity grid. To develop a scenario file for the EAPP, this scenario file was adapted. This was done for both the base case and the high VRE case in two different scenario files. The adaptations made to the scenario file are summarised in **Table 3-8** for the two modelled scenarios. The resulting scenario files are in Appendices 8 and 9. These adaptations were also undertaken for the validation scenario of the 2023 Kenyan grid. The adaptations adjust the power plant profiles for the five East

African countries, including the technologies that were projected to be installed by 2025. The Germany 2019 scenario is a sample scenario developed by the AMIRIS team for testing purposes and includes generation technologies, such as nuclear and lignite coal. These are not installed on the Eastern African grid and were removed in the scenario files.

Table 3-8

Adapted Parameters in Scenario files compared to Germany 2019

Parameter Adapted	Germany 2019	EAPP Base 2025	EAPP High VRE 2025
Duration of run	30/12/2018 – 31/12/2019	30/12/2024 – 31/12/2025	30/12/2024 – 31/12/2025
Value of Lost Load	3000	1500	1500
Storage Trader	Pumped Hydro	Battery	Battery
Support Policy	PV(FiT), Wind (FiT), Hydro Run-off-River, PV, Wind Onshore, and Wind Offshore	PV(FiT), Wind (FiT), Hydro Run-off-River, PV, and Wind Onshore	PV(FiT), Wind (FiT), Hydro Run-off-River, PV, and Wind Onshore
Geothermal Plant	Not included	Included for ET,TZ and KE using a conventional plant operator	Included for ET,TZ and KE using a conventional plant operator
Conventional Plant operators	5 operators. Lignite coal, nuclear, hard coal, natural gas combined (combined cycle and gas turbine), and HFO.	8 operators. Natural gas combined cycle, geothermal, methane, and HFO. Lignite was adapted to Geothermal.	8 operators. Natural gas combined cycle, geothermal, methane, and HFO. Lignite was adapted to Geothermal.
FiT Operators	3 for wind, solar and hydro run-of-river	7 for wind, solar and hydro run-of-river	7 for wind, solar and hydro run-of-river
Bio Energy Operators	One operator	Four bio-energy operators	Four bio-energy operators
Solar Operators (non-FiT)	6 solar operators non-FiT	4 solar non-FiT operators	4 solar non-FiT operators
Wind Operators (non-FiT)	5 wind onshore non-FiT operators and 3 wind offshore operators	3 wind non-FiT operators	3 wind non-FiT operators

The ‘Schema’ file was not altered as it represents the main engine for the AMIRIS version and only processes. The contracts files were altered to reflect the traders and operators in the EAPP base and high-VRE scenarios.

3.4.1.3. Modelling Assumptions

The assumptions made in the modelling process are described below.

- i. **The EAPP is modelled as a single zone with uniform pricing:** The five countries of the EAPP are modelled as a single zone or uniform market. This assumes a uniform pricing regime over the countries. This implies a uniform price determined by the marginal price of the market. The pricing difference related to the location of supply and demand is built into the zonal price.

This assumption contrasts with modelling each country as its own zone and applying nodal pricing at the nodes where cross-country transmission occurs. Another alternative is full nodal pricing. Currently, each country has its own electricity pricing system, which is mainly based on tariffs determined through power purchase agreements. This implies a zonal pricing arrangement. The AMIRIS version did not allow zonal pricing. Uniform pricing does not cater to congestion and does not reflect the true marginal cost of serving specific locations (Weibelzahl, 2017).

This implies that the model pricing outputs are theoretical and would not represent real-world levels affected by congestion on transmission lines. The system operator must implement costly out-of-market redispatch actions to respect physical constraints, effectively subsidising imports into congested areas and penalising exports from

generation-rich zones. This resultant congestion rent is not captured by any market participant and is a loss to social welfare.

- ii. **Infinite Transmission Capacity:** The simulation assumes an infinite transmission capacity across the countries of the EAPP, and as such, any amount of electrical energy can be moved across different grids at any time. Infinite transmission does not exist because all lines and interconnectors have capacity limitations for safe operations.

This assumption implies that congestion between different countries is not considered in this simulation; thus, spikes in pricing owing to the limited availability of transmission capacity would not be captured.

- iii. **Country-level power plants are combined by technology:** The simulation combines the capacities of power plants with similar technologies per country and represents them as one power plant. This allows for anonymity and ease of processing by the AMIRIS model. For instance, all the geothermal plants in Kenya are modelled as one geothermal plant with a capacity of 1025 MW. This assumption causes deviations in the results, as each individual power plant has its own operation regime and parameters. This is especially relevant for location-specific VREs. For instance, different hydropower projects located in the same country will have different river regimes and flooding and drought patterns. These deviations are, however, not considered significant. The combination of plants also allows for reduced computing needs and easier generalisation.

- iv. **Dispatch is according to European electricity market rules.** The market rules of the EAPP are currently under development. The AMIRIS model applies European electricity market rules and uses the marginal price to clear and settle the market. This approach applies feed-in-tariff (FiT) rates to generators who benefit from such support structures. The simulation also applies FiT rates where they are defined in the EAPP markets

considered. This assumption aligns with current thinking regarding EAPP market operations.

- v. **Modelling of Dammed Hydro and Geothermal plants :** The modelling of dammed hydropower plants and the regime of control of these dams has proven to be difficult in the modelling of electricity markets (Nepal et al., 2023). This simulation models all hydropower plants installed in the targeted EAPP markets as run-of-the-river plants that rely on the levels of the rivers on which they are installed to determine their operational regime. In this sense, the simulation considers hydropower plants as a varying renewable energy technology dependent on the hydrology of the rivers in which they are installed. The geothermal plants were modelled as conventional power plants with zero CO₂ emissions. Geothermal plants function similarly to other thermal plants, except that the heat source is steam from the Earth's crust. This modelling should be sufficient.
- vi. **High VRE scenario:** The research undertakes a simulation of two main scenarios for the targeted EAPP countries. The first scenario is based on the installed power plants in the five countries as of the end of 2025. The simulation also defines a high renewable energy penetration scenario. This scenario considers the planned installations of new power plants by end of 2025 based on the various planning documents of the five countries. Some of the major differences in this scenario are as follows:
 - Significant increase in wind and solar capacity in Ethiopia. This was modelled as increasing from 324 MW to 3514 MW and from 0 MW to 1675 MW, respectively.
 - Installation of 250 MW battery storage in Kenya
 - Installation of geothermal power plants in Ethiopia (207 MW) and Tanzania (95 MW)
 - Installation of grid-scale solar (205 MW) and wind (100 MW) in Tanzania.

This assumption follows the countries generation plans, which are often not adhered to and contain overly optimistic onboarding of the new generation. For instance, it will have Ethiopian wind dominate the market.

3.4.1.4. Input Data Sources

The AMIRIS model requires a specific set of data to be collected to enable the execution of simulations. The data input into the model are listed in **Table 3-9**. The model requires time-series profile values for demand, solar resources, wind onshore resources, bioenergy resources, geothermal resources, hydropower resources, natural gas pricing, CO2 pricing, and HFO costs. These were externally derived and input into the model to allow for simulation. The derivation of these time series and other data is described in this subsection. These data inputs are necessary for the parameterisation of AMIRIS. Where a data input is missing, then the related powerplant defaults to AMIRIS data. This can however be ignored by putting the capacity to zero for a non-existent powerplant for the EAPP case. Lignite coal power plant is an example of this.

Table 3-9

Data required for the AMIRIS Model

Data Description	Data Unit	Data length
Power plant data for the EAPP	MW	27 datapoints
Demand Eastern Africa 2025	MWH	8760 datapoints
Solar Resource – KE, UG, TZ, ET and RW	kWh	8760 datapoints
Wind speed profile-KE, ET, TZ	m/s	8760 datapoints
Bioenergy profile (Dispatch)	%	8760 datapoints
CO2 Price	EUR/ton	
Geothermal Profile	EUR/MWH	
Hydropower Profile- Generic and ET	m3/s	8760 datapoints
Natural gas costs	EUR/MWH th	Monthly
HFO costs	EUR/MWH th	Monthly
Availability – Generic	%	

3.4.1.4.1. Power Plant Data for the EAPP

The power plant data for the EAPP countries selected for the simulation were gathered from the countries power development master plans at the time of the research (ERA Uganda, 2021; MoE, 2022; MoE Tanzania, 2020; Rwanda Energy Group, 2022; USAID Power Africa, 2021). These included installed capacity data in megawatts for operational and planned power plants, with a cutoff of 2025 chosen for the simulation.

The data included various technologies applied in power generation in the region, including wind, solar, hydropower, thermal (heavy fuel oil, liquified natural gas, and methane), geothermal, and storage capacity. The data was collected per country and combined by technology for each country, and a specific code was assigned to the technology and country. The codes were two-digit codes with the first digit representing the technology and the second digit representing the country. For instance, the two-digit code 61 represents the combined installed solar power capacity in Kenya. The digit 6 represents solar, and the digit 1 represents Kenya. A full description of the coding system is provided in **Table 3-10**.

Table 3-10

Coding of Country and Power plant data

Powerplant Technology	Technology Code	Country	Country Code
Hydropower	1	Uganda	0
Thermal Power (HFO)	2	Kenya	1
Thermal Power (LNG & CH4)	3	Tanzania	2
Geothermal	4	Ethiopia	3
Bioenergy	5	Rwanda	4
Solar	6		
Wind	7		
Storage	8		

Table 3-11*Powerplant data for Base and High-VRE scenarios*

Hydro Power Plant	Power plant Code	Base Case Installed Power (MW)	High VRE Installed Power (MW)
Uganda	10	1,757.10	1,757.10
Kenya	11	859.01	859.01
Tanzania	12	2,770.00	3,128.61
Ethiopia	13	9,830.00	9,830.00
Rwanda	14	169.84	169.84
Thermal Power Plant (HFO)			
Uganda	20	100.00	100.00
Kenya	21	586.32	586.32
Rwanda	24	149.80	149.80
Thermal Power Plant (LNG)			
Tanzania	32	962.00	1,262.20
Thermal Power Plant (CH4)			
Rwanda	34	30.00	29.79
Geothermal Power Plant			
Kenya	41	1,025.20	1,025.20
Tanzania	42	-	95.00
Ethiopia	43	-	207.30
Bioenergy Power Plant			
Uganda	50	87.00	112.00
Kenya	51	39.44	39.44
Ethiopia	53	86.00	136.00
Rwanda -Peat	54	50.00	50.00
Storage (Battery) Plant			
Kenya	81	-	250.00
Solar Capacity			
Uganda	60	50.00	70.00
Kenya	61	251.75	251.75
Tanzania	62	-	205.00
Ethiopia	63	-	1,675.00
Rwanda	64	12.05	12.05
Wind Capacity			
Uganda	70	-	20.00
Kenya	71	435.50	485.50
Tanzania	72	-	100.00
Ethiopia	73	324.00	3,514.00
Total Power Capacity (MW)		19,575.00	26,120.90

Power plant data were collected for a base case and a high-VRE case. The base case is a combination of power plants that are already operational and those under construction and expected to be operational by 2025. The high-VRE case includes power plants in the base case and those that have been planned to be operational by 2025 in the various power master plans reviewed. The coded dataset is described in **Table 3-11**.

3.4.1.4.2. Demand Timeseries

The demand timeseries for the EAPP countries was derived using a file of the annual hourly demand timeseries of Kenya for 2023 acquired by the researcher from the Kenyan Utility. The timeseries and its peak demand defined for the year 2023 were then used to derive the timeseries for the year 2025 for each of the five EAPP countries. The data were cleaned for anomalies in the Kenyan grid in 2023 (incidents of national blackouts). For this derivation of a demand profile, it was assumed that the demand profile for these countries is similar to that of Kenya, as depicted in **Figure 3-7** and **Figure 3-8**.

Figure 3-7

A 24hour demand profile of Kenya on 9th of January 2023

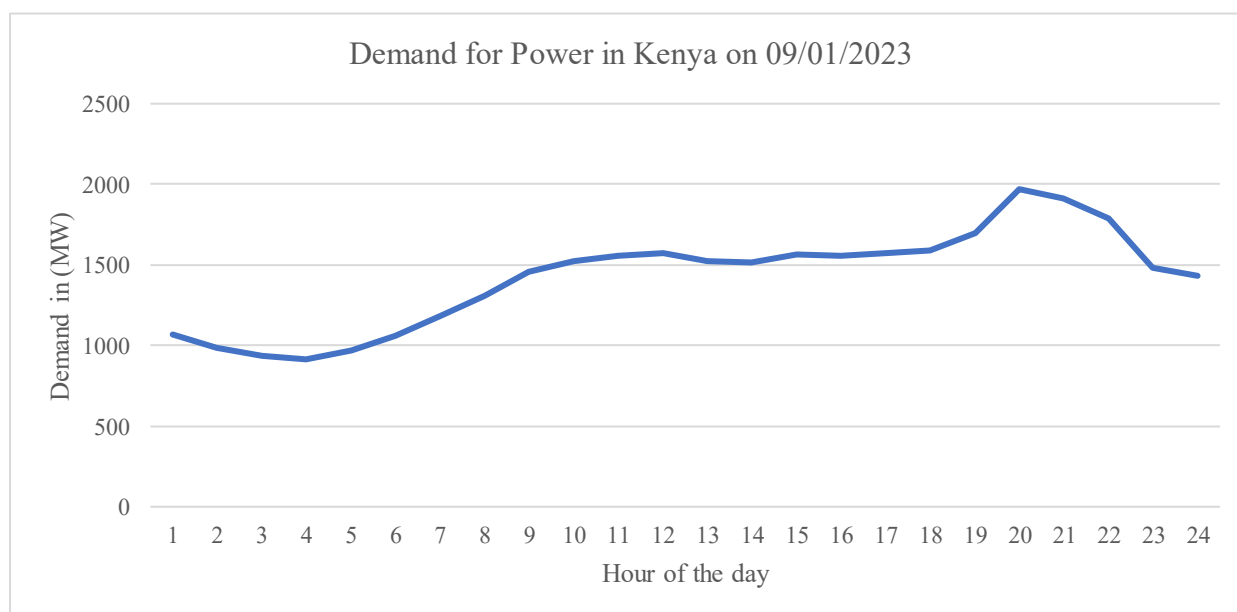
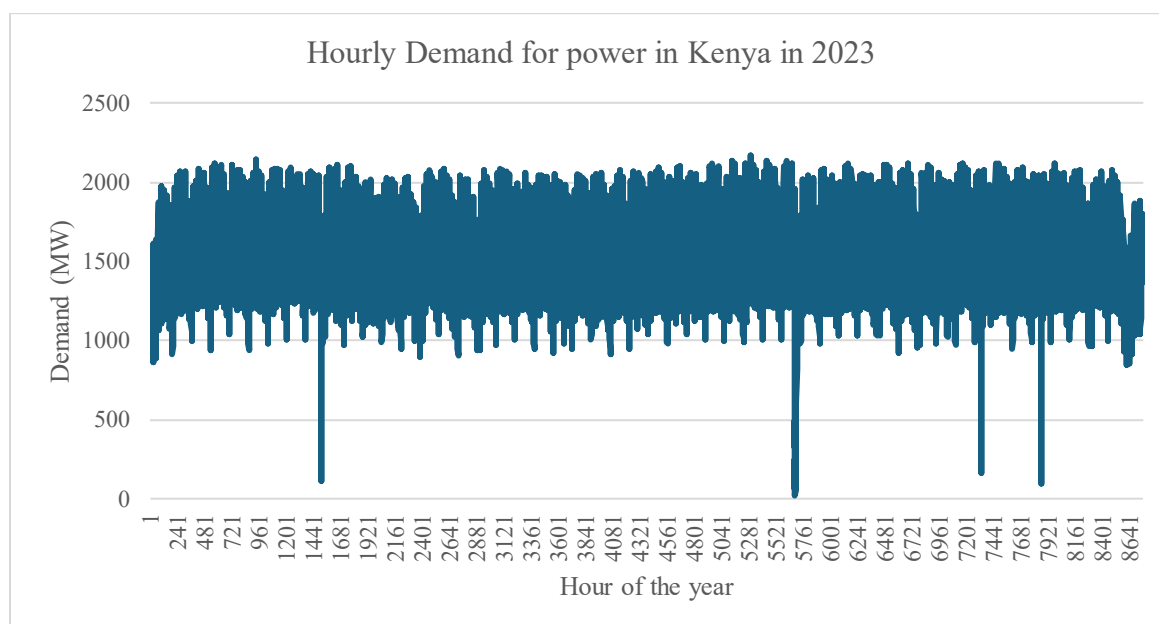
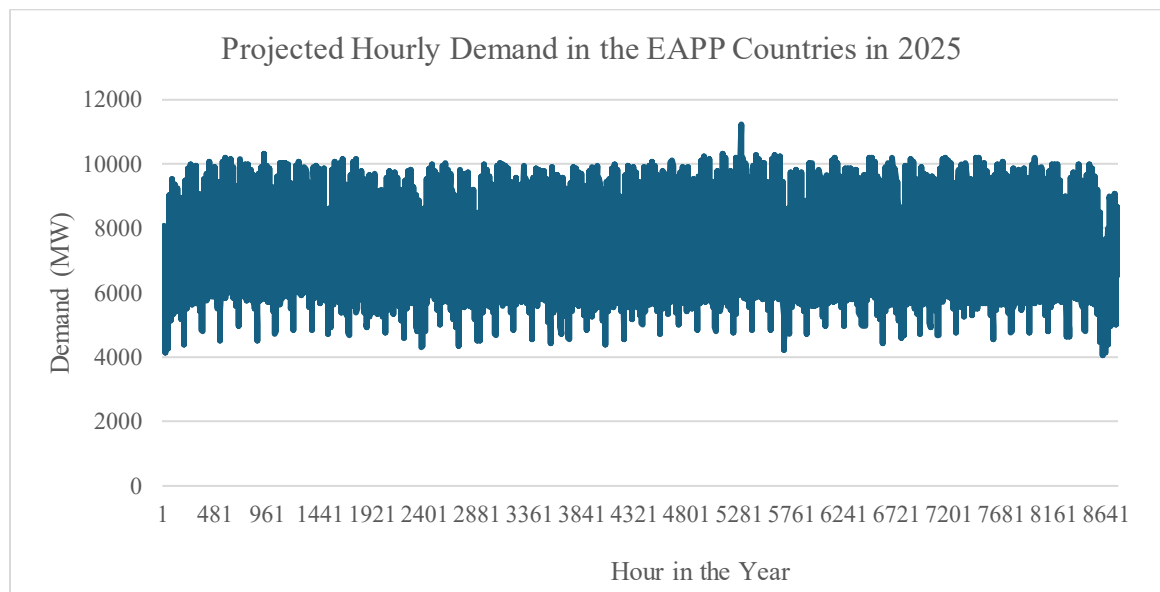


Figure 3-8

The annual demand profile of Kenya in the year 2023



The peak demands from the various countries as anticipated for the year 2025 as guided by the respective least cost power development plans of the countries (ERA Uganda, 2021; MoE, 2022; MoE Tanzania, 2020; Rwanda Energy Group, 2022; USAID Power Africa, 2021) were then used to derive an hourly timeseries of demand for a whole year. This time series of the EAPP demand for 2025 was used as the demand input for both the base and high VRE scenarios and is depicted in **Figure 3-9**.

Figure 3-9*Hourly demand profile of the EAPP for 2023***3.4.1.4.3. Solar Resource Timeseries**

The solar time series was derived using the global solar atlas developed by SolarGIS and the World Bank Group (SolarGIS & World Bank, 2024). For the solar PV power plants, a location in Eldoret, Kenya, at longitude 0.521843 °and latitude 35.282593 °was chosen. The solar power plant was assumed to be ground-mounted with an azimuth of 180°, a tilt of 5°, and a capacity of 1000 kWp. The global solar atlas was then used to generate an hourly time series for the location. Eldoret is home to three of Kenya's five large solar farms, each with a capacity of 40 MW. The time series derived from the solar atlas is shown in **Figure 3-10**. The data assumes a 1000 kWp plant; thus, each hourly data point corresponds to a kWh value out of a maximum of 1000 kWh. To derive a normalised time series for the model, the hourly data is divided by 1000, producing an hourly normalised time series that can be applied to any size of solar project located in Eldoret.

Figure 3-10*Average hourly profile for Eldoret site***Average hourly profiles**

Total photovoltaic power output [kWh]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0 - 1												
1 - 2												
2 - 3												
3 - 4												
4 - 5												
5 - 6			0.075	0.852	3.537	1.455	0.714	0.421	1.640	5.657	8.405	2.750
6 - 7	68.115	61.092	65.489	93.238	99.740	77.118	67.297	79.975	120.477	147.561	148.944	129.357
7 - 8	310.717	305.917	306.522	298.766	292.877	247.443	230.553	268.529	349.516	365.343	349.445	349.184
8 - 9	512.517	520.686	518.806	492.127	477.574	423.463	404.855	456.934	551.834	557.878	528.883	530.553
9 - 10	659.158	677.823	671.824	633.276	607.961	555.777	541.298	597.336	686.238	675.742	650.327	664.559
10 - 11	739.596	759.921	749.804	705.758	667.081	627.182	613.927	666.638	735.424	724.764	709.033	738.519
11 - 12	754.442	776.451	763.907	715.378	662.388	633.106	622.258	666.641	707.703	719.220	715.421	754.826
12 - 13	710.925	732.332	729.812	672.305	620.771	572.711	549.973	582.238	646.412	675.154	675.570	709.469
13 - 14	629.140	652.725	651.443	570.642	528.456	467.661	448.905	452.028	530.383	565.607	583.637	630.839
14 - 15	509.636	536.014	538.831	433.557	396.991	341.004	326.976	313.158	406.607	422.469	445.197	499.907
15 - 16	361.956	386.823	363.764	282.297	253.842	219.944	207.393	201.408	261.149	261.330	281.837	340.451
16 - 17	193.225	213.007	182.998	128.798	102.884	100.659	104.934	104.044	112.187	97.772	111.045	147.848
17 - 18	28.343	35.056	22.684	11.815	4.459	8.612	14.426	13.557	4.667	2.610	4.251	6.663
18 - 19												
19 - 20												
20 - 21												
21 - 22												
22 - 23												
23 - 24												
Sum	5,478	5,658	5,566	5,039	4,719	4,276	4,134	4,403	5,114	5,221	5,212	5,505

Note. Sourced from SolarGIS & World Bank, (2024)

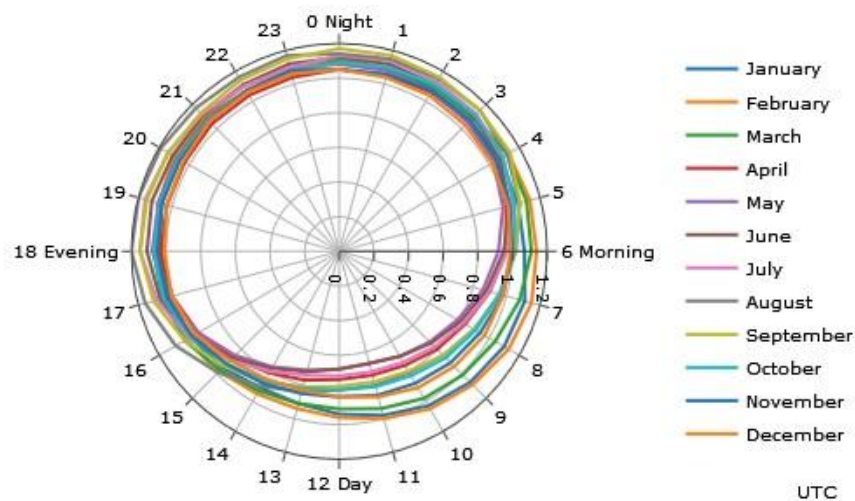
All solar projects in the five EAPP countries are assumed to have the same solar profile as this site in Kenya, and this timeseries is used to derive their output. The simulation combines the installed capacities per country for various technologies into one powerplant. Eldoret is close to the equator, and all five countries are within 14 °North or South of the equator. The solar resource is thus assumed to be similar, with slight deviations in southern Tanzania and northern Ethiopia. Eldoret experiences cool temperatures year-round, which are ideal conditions for solar photovoltaic power plants. The use of this timeseries for the five countries was not expected to significantly distort the actual production and allowed for ease of modelling.

3.4.1.4.4. Wind Onshore Resource time series

The wind timeseries applied in the model was derived from the Global Wind Atlas developed by the Danish Technical University and the World Bank Group (DTU & World Bank, 2024). A generic wind turbine with a rated power of 3.45 MW, IEC class 2W, hub height of 100 m, rotor diameter of 126 m, design annual average wind speed of 8.5 m/s, and operating air density of 1.225 kg/m³ was assumed. Two locations were used to generate two profiles. The first was the Loiyangalani area in Marsabit County, Kenya, where the Lake Turkana Wind Power Plant is located.

Figure 3-11

Hourly vs monthly radar plot for Loiyangalani



Note. Sourced from (DTU & World Bank, 2024)

Hourly radar plot data were used to derive the hourly time series for the site. **Figure 3-11** shows a sample hourly radar plot for the location longitude 2.528781°, and latitude 36.78772°. This was then used to derive an hourly time series. This location was chosen

because of the impact of the Lake Turkana site on wind electricity production in Kenya and because the site has an unusually high capacity factor, which is unusual for wind sites. The time series was used for Kenyan wind power plants.

The second site used was at a longitude of 8.580342° and a latitude of 39.249001° in the Oromia region of Ethiopia, close to the location of the Adama wind farm in Ethiopia. This site has an average capacity factor and its timeseries is assumed for wind farms in Ethiopia, Uganda, and Tanzania. Wind resources are highly site-specific; thus, combining all wind farms in a country into one large wind farm for modelling purposes will introduce errors. However, the assumptions were deemed appropriate because, in both cases, the assumptions made represented the closest to reality in terms of the locations of the installed and expected wind farms.

3.4.1.4.5. Hydropower Timeseries

The generic files in the German 2019 sample case in AMIRIS were adapted as the annual timeseries for hydropower and bioenergy. Hydropower profiles depend on the specific river, plant operation regime, and type of hydropower plant (dammed or run-of-the-river). This detailed data was not available for the hydropower plants in the EAPP and, thus, for the combination of country-level power plants, the available timeseries representing a combination of power plants (though from a different geographic location) was used to simplify the modelling. This adoption of generic data in the model introduces higher availabilities due to the low occurrence of drought situations in German affecting the hydropower stations. This compared to prolonged period of high hydrology in the EAPP countries.

The modelling of hydropower in ABMs is challenging because it requires establishing an optimal operation strategy, including the possibility of reverse pumping of water (Ferreira

dos Santos & Tomé Saraiva, 2021). This challenge is faced in other simulation approaches because of the difficulty in predicting water availability and the operational constraints of hydropower. Detailed plant-level data is needed beyond the flows to effectively model hydropower reservoirs (Shah et al., 2025). Modelling has been conducted for hydropower using simplified representations.

Previous research approaches have attempted to overcome this challenge for specific grids, such as China (J. Zhou et al., 2025). This simplification impacts the accuracy and reliability of the results on energy dispatch, pricing, and system stability. It also obscures benefits of ancillary services from hydropower in a dynamic grid with high VRE penetration (Haugen et al., 2024). To overcome this, detailed information on specific hydropower plants is required. This was not available for this research. To enable incorporation of hydropower plants they were modelled as run-of-river powerplants with the AMIRIS generic timeseries adopted. Though this weakens the research by introducing inaccuracies primarily in operational flexibility and thus energy production. Dammed hydropower allows for better integration of VREs. In this sense dammed hydro if well represented would enable more dispatch of VREs (Haugen et al., 2024; Turner & Voisin, 2022; D. Wang et al., 2024).

3.4.1.4.6. *Bioenergy Timeseries*

Similar to the hydropower timeseries, the bioenergy modelling in AMIRIS adapted the generic bioenergy timeseries in AMIRS derived from the German scenario. Bioenergy output depends on the availability of feedstock, conversion efficiency, and maintenance schedules at a specific powerplant level (Lehneis, 2025). This introduces complexity in a system-wide aggregation of bioenergy powerplants, as unique powerplant metrics must be determined

hourly. This would introduce complexity to the model. The time series representation does not account for the availability of biomass and other power plant operational aspects.

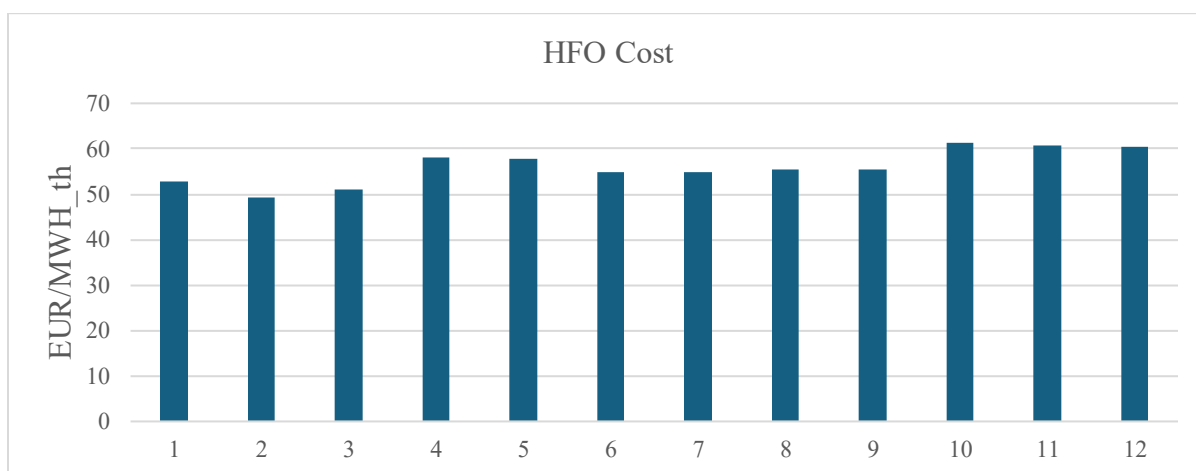
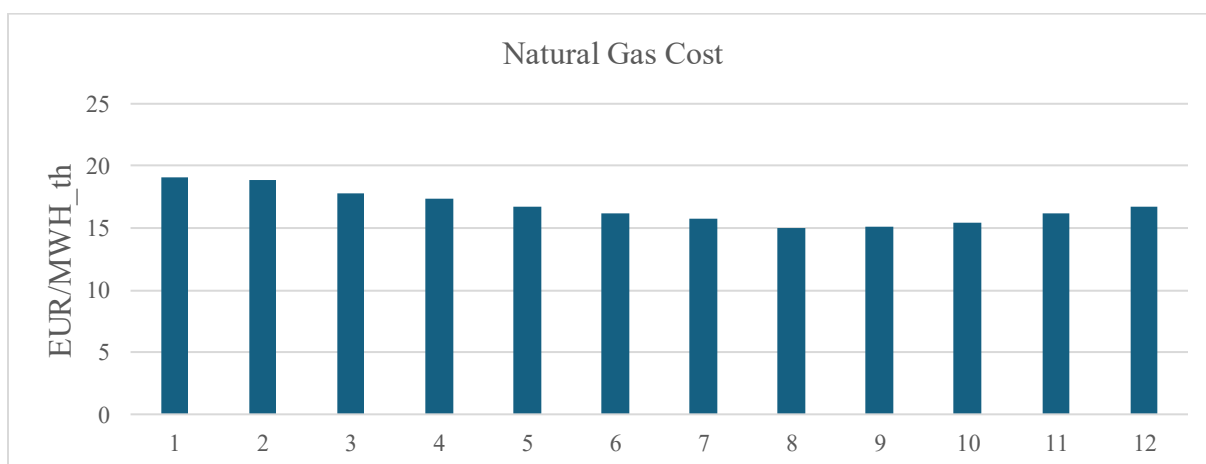
German bioenergy power plants have operated for over a decade, with abundant data on their production profile (Lehneis, 2025). There is limited experience with the operation of grid-connected bioenergy plants in the EAPP. The adoption of default bioenergy data thus approximates an ideal situation. The low volume of bioenergy installed capacities in the EAPP implies minimal impact on market outcomes.

3.4.1.4.7. Geothermal Resource

Geothermal plants were modelled as conventional plants; thus, they did not require a timeseries because they were assumed to be dispatchable. The prices for energy from geothermal were set to the price of the average geothermal generation price in Kenya, as calculated from the Kenyan economic merit order of dispatch.

3.4.1.4.8. Natural Gas, HFO and CO2 Pricing

The international LNG and HFO prices for 2023 were assumed to be the prices that would prevail in 2025. The prices for these commodities are unpredictable and volatile; therefore, 2023 data were used for stability analysis. **Figure 3-12** and **Figure 3-13** give a depiction of the pricing levels for LNG and HFO.

Figure 3-12*Data set of monthly cost of HFO used in the model***Figure 3-13***Data set of monthly cost of LNG used in the model*

The CO₂ pricing for the German 2019 sample case in AMIRIS was adopted for the modelling because the EAPP does not have a CO₂ market. The CO₂ pricing was incorporated to allow for the effective running of the model. The time series comprised sampled pricing for 13 to 19 days per month.

3.4.1.5. Validation of the Model

The model was validated according to the recommendations in the literature by performing both quantitative and qualitative validations of its structure and simulation outputs (Law, 2022; Sargent, 2010).

External Validation

A Kenyan scenario for the year 2023 was established using the quantitative approach. These results were compared with the energy data published by the regulator, EPRA, and Kenya Power Company for 2023. The total energy awarded in the simulation varied by 0.58% from the data reported by the regulator EPRA in the 2023 results. These results are summarised in **Table 3-12**.

Table 3-12

Comparison between simulation results and actuals in Kenya for 2023

	Simulation Value for 2023	EPRA/KPLC statistics 2023
Total Energy (GWH)	13,212.151	13,289.63
Dispatch System Cost (EUR)	740,537,551	971,899,900
Average electricity price (EUR/MWH)	167	73.13
Per Unit Dispatch System Cost (EUR/MWH)	56.05	73.13

Note. Data sourced from (EPRA, 2023; KPLC, 2023)

The results show that the simulation produces a significantly higher average electricity price of 167 EUR/MWH, which is attributed to accounting for the cost of loss of load (load shedding) at peak at the maximum price of 1500 EUR/MWH and the minimum cost of -500 EUR/MWH for oversupply. A direct division of the dispatch cost with the total energy yields a lower cost of 56.05 EUR/MWH, which is consistent with the lower overall dispatch cost. The

167 EUR/MWH is the cost to the economy of the supply. The electricity price derived for the model factors in the cost of oversupply and undersupply.

A comparison of the dispatched or awarded energy by technology according to the simulation for a Kenyan scenario in the year 2023 was also performed, and the numbers were compared with those reported by Kenya Power Company and the Kenya regulator, as summarised in **Table 3-13**.

Table 3-13

Comparison between simulation results and actual awarded energy by technology type in Kenya for 2023

	Energy Awarded in simulation (GWH)	Energy Awarded in EPRA and KPLC statistics (GWH)
Geothermal	6,787	6035
Hydro	2,976	2569
Wind	2,357	2202
Thermal	688	1396
Net Imports	-	644
Others	404	444
Total	13212	13290

Note. Data Sourced from (EPRA, 2023; KPLC, 2023)

The simulated energy by technology is similar to the actual data from KPLC and EPRA, with significant deviations in hydro (+16%), thermal (-51%), and geothermal (+12%). This is explained by the drought conditions experienced in Kenya in 2023, which resulted in less dispatch of hydropower and more dispatch of thermal power. The available statistics for 2023 cover July 2022 to June 2023 and not the calendar year 2023. This also introduces a minor deviation between the two sets of data.

For qualitative validation, the simulation results were presented to key informants in a semi-structured interview. This validation approach is also known as the Turing test (Sargent,

2010). Eleven key informants were interviewed for the study; their demographics are described in **Table 3-14**.

Table 3-14

Demographic data of the surveyed informants

Metric	Number
Countries ³ and regional bodies ⁴	3
Average years of Experience	23.2
Population	500
Sample Size	20
Successful Interviewees	11
Response rate (% of sample size)	55%

The results of these interviews are presented in Section 4.4, under Research Question 2. The key informants viewed the model as sufficient but required the inclusion of transmission capacities and consideration of political influences on the pool. The informants also noted that the model needed to consider the unit commitment needs for power plants (the minimum level of operation required by each power plant) and the ramp rates of each power plant to be reflective of the realities of the grid.

The model and validation simulation findings represented the actual situation because the energy dispatched closely matched in the simulation and in reality. The cost variations tied to the different costing approaches of the model and the Kenyan market do not pose a risk of misinterpretation, as the costing approaches for a wholesale market are expected to vary from those of an unbundled market based on bilateral contracting. As the research models a

³ Kenya, Uganda, Tanzania, and Ethiopia

⁴ Representatives from the Eastern Africa Power Pool secretariat and the Energy Regulators Association of East Africa

wholesale market for the EAPP, the model was deemed appropriate. Thus, a simulation scenario for 2025 for the EAPP could be reliably developed.

3.4.1.6.Scenario Design

Main Scenarios

The modelling was undertaken based on two main scenarios considering the level of VRE on the grid for the five EAPP markets in 2025. There were a base case and a high VRE case. These cases differed in the level of VRE in the grid. The base case had 5.5% of the total capacity installed as wind and solar, whereas the high VRE case had 24.2% of the total capacity installed.

This base scenario corresponded to power plants that were expected to be ready by 2025 and connected to the grid based on evidence of the commencement of construction or operations. In total, for the five EAPP countries, 19,575 GW was available with wind and solar capacity representing 1.073 GW. The shares of the different technologies are detailed in **Table 3-11**.

The high VRE scenario corresponded to the projections of the installed capacity for various countries for the year 2025, according to their national power generation expansion plans at the time of the research (ERA Uganda, 2021; MoE, 2022; MoE Tanzania, 2020; Rwanda Energy Group, 2022; USAID Power Africa, 2021). The total installed capacity for 2025, according to the expansion plans, was 26.120GW, of which wind and solar were expected to contribute 6.333GW. The shares of the different technologies are presented in **Table 3-11**.

Sensitivity Scenarios

Three sensitivity scenarios were run to test the robustness of the findings from the base and high-VRE cases and to examine the effects of specific market designs and operational assumptions on electricity pricing and dispatch outcomes. These scenarios were informed by the themes that emerged from the key informant interviews, which highlighted geothermal dispatch priority, the effects of intermediate VRE penetration levels, and the market price implications of the high-VRE case as areas warranting further investigation. The sensitivity scenarios are described below.

i. Medium VRE Scenario

The medium-VRE scenario was designed to model a level of VRE penetration intermediate between the base case (5.5% of total installed capacity as wind and solar) and the high-VRE case (24.2%). The scenario was constructed by setting every agent that differed between the base and high-VRE cases to exactly the midpoint of those two values. Thirteen agents changed between the base and high-VRE cases, contributing a combined increase of 5,546 MW in total capacity. The detailed capacities in the three scenarios are presented in **Table 3-15**.

Table 3-15*Capacities in the Base, Medium VRE and High VRE scenarios*

Agent	Base (MW)	Medium RE (MW)	High RE (MW)
ET Wind	324	1,919	3,514
ET Solar	0	837.5	1,675
TZ Hydro	2,770	2,949	3,129
Storage	0	125	250
ET Geothermal	0	103.65	207.3
TZ Solar	0	102.5	205
TZ LNG	962	1,112	1,262
TZ Geothermal	0	47.5	95
ET Bioenergy	86	111	136
KE Wind	435.5	460.5	485.5
UG Bioenergy	87	99.5	112
TZ Wind	0	50	100
UG Solar	50	60	70
UG Wind	0	10	20
KE Geothermal	1,025	1,025	1,025
KE Solar	251.75	251.75	251.75
ET Hydro	9,830	9,830	9,830
TOTAL	15,821.25	19,093.9	22,367.55

The medium-VRE scenario, therefore, adds precisely +2,773 MW of new capacity, placing it exactly halfway between the two main cases in terms of total installed capacity. This approach ensured that the medium-VRE case was methodologically consistent with the base- and high-VRE cases, and that any differences in outcomes could be attributed to the change in VRE capacity rather than to other modelling variations.

This scenario was designed to determine whether the pricing and dispatch effects observed in the high-VRE case emerge gradually as VRE penetration increases or are concentrated at the higher end of the penetration range. This question is relevant to the EAPP context because it directly relates to the pace at which market design interventions, such as

price floor mechanisms, storage incentives, and dispatch priority rules, must be introduced as VRE deployment progresses.

ii. Geothermal Must-Run Scenario

The geothermal must-run scenario was designed to test the effect of assigning dispatch priority to geothermal power plants, overriding the standard marginal pricing-based dispatch order applied in the base and high-VRE cases. In the main simulations, geothermal plants were modelled as conventional power plants that bid into the market at their marginal cost and were dispatched accordingly. However, in practice, the technical characteristics of geothermal plants (their slow ramp rates, high capital costs, and very low variable costs) mean that they are typically operated as baseload plants and are not routinely cycled down in response to short-term market conditions (DiPippo, 2015). Key informants raised this as a significant gap in the base model, noting that geothermal operators in Kenya, in particular, would be unlikely to accept market-based dispatch arrangements that expose their plants to the risk of being undercut by lower-cost VRE bids during high-renewable hours.

In this sensitivity scenario, geothermal plants were assigned a must-run status, meaning that they were dispatched at their full available capacity, regardless of the market-clearing price. All other aspects of the simulation, including the power plant portfolio and market rules, were held constant at the high-VRE case configuration. Therefore, this scenario isolates the effect of geothermal dispatch priority on market pricing and on the dispatch of other generation technologies, particularly VRE plants, during hours when geothermal output and VRE generation overlap. It was anticipated that assigning a must-run status to geothermal would reduce the headroom available for VRE dispatch during low-demand or high-renewable hours and would exert upward pressure on market-clearing prices in hours in which geothermal

capacity displaces generation that would otherwise have cleared the market at a lower or negative marginal price.

iii. Optimal VRE Capacity Scenario

The optimal VRE capacity scenario was designed to identify the level of VRE capacity addition beyond the base case at which the annual mean market price crosses zero. This point represents the transition from a net positive to a net negative annual mean in the aggregate effect of VRE on market pricing. This scenario addresses a question raised by the high-VRE simulation results, in which the mean annual market price indicates that the planned VRE expansion significantly overshoots the capacity at which the market can sustain a positive mean price.

The scenario was formulated by introducing a scaling parameter, *alpha*, which represents the proportion of the additional VRE capacity in the high VRE case that is added to the base case. A value of $\alpha = 0$ corresponds to the base case, and a value of $\alpha = 1$ corresponds to the full high VRE case.

The three sensitivity scenarios collectively extend the scope of the quantitative analysis beyond the two main simulation cases. They allow for the testing of specific operational assumptions, intermediate VRE penetration, geothermal dispatch priority, and the capacity threshold for a positive mean market price, which were identified as relevant to the EAPP context through key informant interviews. The results of these sensitivity scenarios are presented alongside the main simulation findings in Chapter 4.

3.4.1.7. Model Terms Definition

The model uses variables to interpret and explain certain key phenomena. The key variables and terminologies used in this study are described in the next subsection.

a. Variable/Varying Renewable Energy (VRE)

VREs refer to renewable energy technologies that are replenished naturally but have variable output with respect to their rated output. This variation is linked to environmental conditions. This research includes only wind and solar power in the definition of VREs; however, other technologies such as hydropower run-of-the-river are modelled as VREs in AMIRIS. However, hydropower plants are not included in the definition of VRE market penetration levels. This definition is consistent with extant literature (Holttinen et al., 2021; Migliari et al., 2024).

b. Marginal prices

Marginal pricing refers to the concept of the electricity supply price being defined by the cost of the last unit produced to match demand. This forms the basis for pricing in short-term markets. The market-clearing price in a given hour is thus determined by the cost of running an additional more expensive generator than those that are already in operation (Fiuza de Bragança & Daglish, 2016). In this model, marginal pricing is the price for the hour generated by AMIRIS in EUR/MWH.

c. Short-term trading

Short-term trading of electricity refers to the trading of electricity over short temporal horizons. These could be in the form of contractual arrangements over minutes or days. The target is to balance demand and supply and ensure supply in that timeframe (Märkle-Huß et al.,

2018). In this research, the timeframe is hourly intervals. The marginal price is calculated in the AMIRIS model every hour for 8670 hours in the model year of 2025.

d. VRE Market penetration

VRE market penetration refers to the level of incorporation of VREs (wind and solar) in an electricity grid, either in the form of installed capacity or energy utilisation (Holttinen et al., 2021). This integration of VREs is driven by environmental considerations and an attempt to move away from the generation of electricity using fossil-fuel-based power plants. The model penetration level is seen as a percentage quantum of wind and solar installed capacity of the entire installed capacity. This is then used to define two scenarios of high (24.2%) and base (5.5%) penetration levels.

3.4.1.8. Analysis of the Quantitative Data

The simulations provided the outputs as described in **Table 3-5** and **Figure 3-6**. This data on datapoints such as pricing, plant dispatch level, and others was analysed to produce descriptive statistical information, including means, modes, and totals, using MS Excel and IBM SPSS. These were presented in the form of tables and charts that are easy to understand. Trends related to the independent and dependent variables were documented. These allowed for response to the second research question (How would a wholesale electricity market in Eastern Africa be affected by introduction of more varying renewable energy?) and drawing of inferences and conclusions.

3.4.2. The Semi-Structured Interview Questionnaire

3.4.2.1. Introduction

This research involved adapting the AMIRIS model to investigate the short-term market in the Eastern African power pool. Assumptions were made to enable the execution of simulations and scenarios. Two main scenarios were run for the base case and the high-VRE case, and the findings were tabulated. Three additional scenarios were run after considering key informant feedback. These assumptions and findings, along with other questions related to the research questions, were subjected to key informants through semi-structured interviews.

Semi structured interviews were used for the research to address the “*why*”, “*how*”, and “*what else*” behind the simulation findings. A fully structured survey would not allow for spontaneity of thought and opinions from the informants. Unstructured interviews on the other hand would make cross-informant thematic analysis incoherent. The semi-structured interviews allowed for emergent themes to be addressed and increased the depth of response. It allowed for saturation to be achieved faster due to the clear bounds and material presented to informants (M. Hennink & Kaiser, 2022).

Accordingly, a semi-structured questionnaire interview guide and a semi-structured questionnaire were developed (see Appendix 1). Semi-structured interviews were chosen to allow open discussions on the research findings by the expert panel. The interview guide provided an overview of the interview and highlighted the participants’ right to end the interview at any point. It also requires the interviewee to provide consent to answer the specific questions described in the semi-structured interview questionnaire.

The key informants were presented with an informed consent form and a semi-structured questionnaire that was sent to them in advance. The informed consent form provided

a summary of the research and the process to be followed in the interview. The researcher first confirmed that consent was given by the informants and then presented a summary of the findings of the simulation process described above. The presentation slides are attached in Appendix 2.1.

The presentation revealed the research questions and explained the AMIRIS model and its assumptions. A description of the assumptions of the simulations, including the assumption on infinite transmission capacity, the power plant capacities for the base and high VRE cases, and others, was provided. The informants underwent the model validation process with the Kenyan 2023 case and actual statistics from EPRA before being presented with the results of the simulations. The results presented included findings on electricity prices, energy awarded to VREs and conventional plants, CO₂ emissions, and storage plant revenue.

Following this was a questioning session guided by a questionnaire. The interviews were recorded to allow for an easy flow of the conversation and for transcription after the interview. The questionnaire first included a section collecting demographic information, including years of experience, informant role in the sector, and country of operations. This information was collected to understand the experience and demographic representation of the informants. No names were recorded; each participant was assigned an informant number.

The guide questionnaire then asked questions that responded to the first research question on how the electricity market operates and related views to the EAPP. The questions are open ended and allow the informants to respond freely and encourage divergent thought. The key informants' thoughts on a short-term market for the EAPP were sought, as well as whether such a market with more VRE would have any impact on the price of electricity in the region. Views on the findings of the simulation and assumptions of the model were also

collated. The questionnaire ended by soliciting open ended response to the research and researcher. This allowed the key informants to additionally explore any themes that may not be specifically addressed in the guide questionnaire. The interviews each lasted one hour, with the presentation of the simulation results taking up 15 minutes.

The interviews were audio-recorded with the consent of the key informants, with the understanding that the recordings would be useful for the transcription process and to allow for a smooth flow of the dialogue without the researcher having to pause to take notes. The recordings of the semi-structured interviews were then transcribed and coded so that the informants could not be identified. This was done by assigning a specific number to each informant and referring to them by that number in the transcription. Similar themes from the different interviews were identified and the responses were combined to build on the theme. Where new interesting themes were elicited by the informant probing questions were used to dig deeper.

3.4.2.2.Key Informant Data

The qualitative process involved conducting key informant interviews with 11 informants. During the interview, certain demographic data was collected to allow for a better description of the interviewee. This included the years of experience of the respondent, the respondent's gender, the country affiliation or of work of the informant, and the type of organisation (utility, regulator, generator, etc.). This data was used solely for the description of the summarised respondents' demographics, and the specific respondents' names were not recorded. The informants were assigned informant numbers, which served as the basis for documentation in the key informant interviews.

3.4.2.3. Analysis of the Qualitative Data

The qualitative data received from the informants was analysed and grouped into thematic areas with differing opinions and similar themes. These were then used to develop write-ups of the comments and recommendations from the key informants. It should be noted that these informants were presented with the quantitative findings before their qualitative assessments were solicited. This also allowed the research to explore other themes that were not covered by the quantitative processes.

Qualitative coding was undertaken following an inductive coding approach, building from the themes of pricing, dispatch of power plants, and stability of supply. The interview transcripts were reviewed to identify recurring concepts and to gain a good understanding of the data. The quantitative process themes were used to guide the coding of the qualitative process in the first step. New codes were then developed based on the qualitative feedback. These were generated through in-vivo coding from the content of the interview manuscripts. This coding was open to all interpretations of the data to derive codes as guided by previous research (Skjott Linneberg & Korsgaard, 2019).

Inductive coding allows themes to be organically generated from the responses of key informants (Gioia et al., 2013). This was essential because the EAPP market was under development at the time of the research, and key informants had specific views that needed to be derived organically. This qualitative step undertook descriptive coding to allow themes to emerge from key informants' feedback, thereby improving the credibility of the findings (Hsieh & Shannon, 2005).

The initial open coding adapted the three dependent variables: (1) electricity pricing, (2) dispatch of power, and (3) stability of supply. Comments related to these areas were tagged in line with the specific variable. These were aimed at direct triangulation with the quantitative

findings. The qualitative data from the key informant interviews were then parsed to identify and tag themes that were recurring among the eleven informants. These themes extended the study beyond the quantitative view. They added a more nuanced and EAPP-specific qualitative understanding of the wholesale market under high VRE penetration.

The themes identified were unrealistic assumptions, transmission capacity incorporation, technology technical minimums, battery storage, capacity markets, geothermal dispatch, ancillary services, alternative software, political considerations in the EAPP, the EAPP market structure, views on short-term markets, and the demand for electricity.

These themes were refined to collapse overlapping themes and split broad themes. There were an additional five themes that were developed. A further five themes were developed: (1) assumptions of the model and data, (2) EAPP market structure and operations, (3) generation technology considerations, (4) transmission capacity considerations, and (5) political economy of the EAPP. These brought the total number of themes to eight. The combination of quantitative and qualitative findings allowed for a deeper understanding of the research area.

3.4.2.4. Validity of Qualitative Data

Qualitative data validation employs criteria such as credibility, transferability, confirmability, and dependability (Malterud et al., 2016). The research applied coding, rich-thick description and saturation approaches to ensure the validity of the qualitative findings (M. M. Hennink et al., 2017; Ivankova et al., 2006; Phillippi & Lauderdale, 2018).

The coding process undertaken to identify themes in the research broke down the qualitative data into meaningful segments to identify trends and similar themes, further reinforcing the validity of the data. The data was segmented into nine themes that converged the views of the 11 key informants.

The research delved into a rich, thick description of the research context with the biodata of the key informants, their years of experience, and organisational background documented. In addition to documenting the methodological approach, themes, and coding process, these elements also allowed for an audit trail of the research.

Finally, key informant interviews were conducted until saturation was achieved. This is an important indicator of data sufficiency and quality (M. M. Hennink et al., 2017). Code or theme saturation in this research was achieved after eleven interviews with highly experienced key informants, majority of them of PhD level education and with an average of 23 years of experience in the EAPP electricity sector. Previous studies are reported to have achieved theme saturation with nine interviews (M. M. Hennink et al., 2017). Additionally, the robust information power of the interviews as described in literature (Malterud et al., 2016) ensured validity of the qualitative findings.

3.4.3. Integration of Quantitative and Qualitative Approaches

The quantitative analysis ran a model that described the findings of a wholesale short-term market in the EAPP. These generated results related to the main themes of the research, flowing from the independent variables: electricity pricing, dispatch of power plants, and stability of supply. Qualitative research then commented on the findings of the quantitative process and added themes from the lived experience in the EAPP that the quantitative research did not consider but were deemed essential by the key informants.

The integration of quantitative and qualitative findings was undertaken at the interpretation and reporting levels, as in previous similar research (Ivankova et al., 2006; McCrudden & McTigue, 2019; Plano Clark, 2019). This integration aimed to enhance the depth and explanatory strength of this research. The quantitative and qualitative findings were first presented separately, and integration was undertaken at the evaluation of the finding level following the three research questions.

Integration strategies employed at the evaluation level include joint displays, connecting quantitative results to qualitative themes, and narrative integration (Ivankova et al., 2006; McCrudden & McTigue, 2019; Toyon, 2021). A joint display was undertaken for the three themes generated by the quantitative process (electricity pricing, dispatch of power, and stability of supply). Narratives that connect quantitative observations through a qualitative lens were also employed and integrated to enrich the understanding of quantitative findings.

CHAPTER 3.5: OPERATIONAL DEFINITION OF VARIABLES

The quantitative part of the research was based on measuring certain variables through the simulation process. This section provides descriptions of the operational definitions of these variables. Operational definitions of variables define how variables are measured or quantified in a study. The complexity of the research necessitated a set of variables, including independent, dependent, moderating, mediating, and control variables. These are explained in this section.

3.5.1. Independent Variable

The independent variable in this research is the level of penetration of variable renewable energy in the EAPP. For this study, VRE refers to wind and solar energy technologies. The penetration levels of VRE in the grid can be defined as both a measure of the installed capacity of VRE in relation to other sources of generation or as the amount of energy produced or the net load profile supported by VREs as a proportion of the total load or energy produced. This approach has been adopted in previous research on VREs in the Java-Bali power systems (Tumiran et al., 2021).

The level of VRE installed capacity in MWs was compared with the total installed capacity (in MW) on the EAPP. This was considered in the context of two main scenarios: a base case with the actual capacities installed in the EAPP grid and a high VRE case with an increased capacity of VRE on the grid, as defined by power generation expansion plans for 2025. The penetration in terms of the amount of energy produced (in MWh) from the VRE sources was the subject of the EAPP simulation results.

In the base case, the EAPP has 1072 MW of wind and solar installed, representing 5% of the total installed capacity. The high VRE penetration case defines an installed capacity of 6332 MW of wind and solar capacity, representing 24% of the total installed capacity based on 2025 grid expansion plans. Previous research has considered penetration levels ranging between 20% and 80% (Leal et al., 2023; Ríos-Ocampo et al., 2021).

The other variables in this research were examined based on the two described levels of VRE penetration in the EAPP grid.

3.5.2. Dependent Variables

The quantitative part of the research had three dependent variables to be analysed. These were electricity pricing, dispatch of various powerplants, and stability of supply. These issues have been discussed separately.

3.5.2.1. Electricity Pricing

This defines the price of 1 kWh of electricity in the EAPP market. The average EAPP market electricity pricing is derived as the marginal price in the interactions between demand and supply entities in a day-ahead market. This study measured this pricing in euros per MWh. In this case, the price is the resultant marginal price arrived at after matching the hourly demand and supply bids in the wholesale (day-ahead) EAPP market. This definition of pricing in a wholesale market is consistent with the definitions in European electricity markets (Leal et al., 2023; Ríos-Ocampo et al., 2021; Sakaguchi & Fujii, 2021).

The pricing in the model and simulations varies from a floor value of -500 EUR/MWh to a ceiling pricing of 1500 EUR/MWh. This pricing is an hourly value derived through marginal cost pricing in the wholesale market model.

This effect on pricing has been researched in extant literature considering price ranges, time of the price, and area of the pricing (Sakaguchi & Fujii, 2021). This research compares the annual average price of electricity in the EAPP market under the generation sources of the five sampled countries. This price is derived as the average of the hourly prices generated by the wholesale market model.

3.5.2.2. Dispatch of Power Plants

The dispatch of power plants in the research refers to the number of run hours or the amount of energy that a power plant would deliver to the EAPP grid given clearing based on marginal pricing in a day-ahead EAPP grid. This variable was measured in MWh produced per power plant over 8760 h in the scenarios run. The dispatch in MWh can be seen as a comparison between the MWh produced by the power plant as a proportion of the total MWh produced or consumed in the pool in the given period.

The variable is used to quantify this for VREs and other power plants installed in the EAPP in the base and high VRE cases by 2025. Dispatch is defined as the number of hours in a year that a power plant is allowed to produce energy into the EAPP grid.

3.5.2.3. Security of supply

In this research, the security of supply refers to the ability to supply the market with sufficient electrical energy to meet the market demand without resulting in load shedding. Load

shedding is represented by the achievement of the maximum pricing level for a MWh of electricity. The maximum is the ceiling price of EUR 1500/MWh, and the minimum price is - 500 EUR/MWh.

Security of supply in this research is measured by the instances in which the ceiling price occurs under the scenarios defined by the variation in the independent variable (penetration levels of VRE in the EAPP). The occurrence of the ceiling price is an indicator of the inability of the supply to meet the demand in the system. This implies that customers would be disconnected, and existing generation would supply at the maximum pricing.

The effect of VRE penetration is defined in extant research (Beyza & Yusta, 2021; Impram et al., 2020; Jin, 2023) in the context of effects on grid frequency, voltage, and system flexibility needs. This research focuses on effects on pricing of power; dispatch of other power plants and security of supply as defined in this section. This focus has been followed in some of the existing research looking at energy security and pricing in the sense of security of supply defined in this research. Ríos-Ocampo et al. (2021) defined energy security in terms of reliability, reserve margin availability, resilience, and vulnerability. This research focused on inability to supply as a measure of security of supply.

3.5.3. Control Variables

Control variables are essential in the analysis of electricity markets, as they allow the isolation of the specific effects of high penetration of VREs on the grid from other influencing factors (G. Wang et al., 2024). In this case the control variables that were isolated included transfer capacity on transmission lines across the EAPP countries, availability of a market system and availability of powerplants.

3.5.3.1. Transfer Capacity of Transmission Lines

The research considers transmission lines connecting the countries of interest to have an infinite transfer capacity. This implies that there are no physical constraints involved when transferring electrical energy between EAPP countries. Thus, there is no effect on the level of dispatch or the cost of transmission on the overall marginal price. The cost is not included in the derivation of the marginal price. If such transmission costs were included, the analysis of the cost would change from the current relationship between the independent and dependent variables. The availability of sufficient transmission will also affect the dispatch levels of VREs located across borders. The lower the transmission capacity, the lower the cross-country dispatch that can be supported. In this case, the transmission capacity is considered in terms of MW capacity.

3.5.3.2. Availability of Powerplants

The availability of power plants of both RE and conventional natures defines that a powerplant is operational and ready to produce electrical energy. Typical availability numbers for conventional power plants are applied, whereas the availability of VRE plants varies owing to the respective capacity factors and annual resource timeseries applied in the simulation for the specific RE resource. Availability is defined as a percentage value for conventional plants and is guided by the hourly resource profiles that define the level of production at hourly intervals over one year.

3.5.3.3. Availability of a Market System

The research could only be undertaken in a market system. The market system itself being the basis and main platform for the trade in the EAPP. The market system defined for

this research is an energy-based day-ahead market without a balancing and ancillary services market. Trade is based on the matching of demand and supply bids in a marginal-cost-pricing system.

3.5.4. Moderating Variables

Moderating variables in research are those that are essential for computation and running of the model. They define the strength and direction of the relationship between the independent and dependent variables (Bhandari, 2023). These moderators, held in a constant and positive way, allow for independent and dependent variables to establish cause-and-effect relationships within the boundary of the moderating variables. Variations in these moderator variables affect the relationship between independent and dependent variables.

3.5.4.1. Overall Stability of the Grid

The stability of the grid in the EAPP allows for the exchange of energy between the producers and demand centres. In this research, stability refers to the grid operating at the appropriate voltage and frequency to allow for the flow of electricity at a quality that consumer devices can utilise. Stability also implies that the grid has sufficient and well-functioning transmission and distribution infrastructure to support the supply from different power plants to the consumers.

3.5.4.2. Level of Renewable Resource

The research envisioned studying the level of VRE penetration in the grid. The penetration level of renewable energy in the grid is the independent variable. This penetration

can only exist with the availability of renewable energy resources that can be harnessed to produce energy.

The countries of the EAPP are known to have abundant RE resources in hydropower, wind, solar and geothermal sources (Y. Sun et al., 2022). This forms the basis for the variation in the independent variable, and the research is conducted on the basis that there are sufficient RE resources to meet and exceed the demand in the EAPP for the year under review.

3.5.4.3. Political Considerations between Countries

Political considerations between the countries of the EAPP moderate the levels of penetration of renewable energy and, thus, the price and dispatch. The interaction between these dependent and independent variables is affected by political decisions between countries. These could include decisions about energy security and the comfort levels of outsourcing power supply versus own domestic production. This decision would determine whether more VRE would be developed.

Trade policies among countries in the EAPP also affect trade efficiency. The EAPP is heavily influenced by political considerations because of its structural decision-making approach, with its highest organ being the council of ministers, implying that political considerations are key to its success or failure (Elabbas, 2023a).

3.5.5. Mediating Variables

Mediating variables define the conditions and processes under which the independent and dependent variables are related (Bhandari, 2023). These variables define the relationship between independent and dependent variables.

3.5.5.1. EAPP Market Rules

Market rules define how trade is undertaken in a wholesale market. The research through the modelling and simulation applying the AMIRIS model adopts European wholesale market rules. This was necessary as the EAPP market was not live at the time of the research, and the rules were not available. Market rules define the priority of dispatch if based on anything other than prioritisation based on marginal pricing. However, the model is adapted to the prevailing incentive schemes of the EAPP countries, particularly the feed-in-tariff levels for renewable energy projects.

3.5.5.2. Pricing Policy

The applicability of policies related to the pricing of electrical energy in the EAPP will mediate the interactions between the dependent and independent variables. As the research mainly focuses on price variations with increased VRE penetration, if there is a policy, such as a pre-agreed pricing level for generation from VRE, this will affect the overall pricing in the EAPP. Such a pre-agreed pricing level is commonly determined through pre-existing and new bilateral pricing arrangements under feed-in-tariffs and direct long-term fixed tariff negotiations. These power plants are subject to contractual pricing levels for the energy they produce and do not respond to the marginal price. They shape the price of the EAPP market for the periods their supply is utilised.

The known generation tariffs for power plants in the five countries were applied in the modelling. These comprised feed-in-tariff numbers and known generation tariffs for various generation units. These numbers were derived from the generation expansion plans of various

countries. Where these tariffs were not available, the power plants were cleared based on prevailing market prices.

3.5.5.3. Policy on Preferred Dispatch

When there are policies on the dispatch of certain power plants that override marginal pricing, these will mediate the interaction of the independent and dependent variables. For example, preferential dispatch for VREs when available or the intentional curtailing of thermal power plants will affect the dispatch levels of VREs and overall market pricing.

Countries may prefer to have first-right-of-dispatch to locally installed generation in technologies, such as geothermal and hydro, because of the strategic nature of investments in these technologies. Operationally, this is considered from the point of view of the EAPP countries dispatch approaches. In this simulation, dispatch priority was not assigned to any technology outside of marginal pricing considerations.

CHAPTER 3.6: STUDY PROCEDURES AND ETHICAL ASSURANCES

3.6.1. Study Procedures

The study was approved by the UNICAF University in Zambia UREC Ethics Committee on January 31, 2023, prior to data collection, as evidenced by the research ethics approval form in Appendix 3. The research approach chosen was a mixed methods approach with a sequential explanatory approach. The quantitative phase was the first step in the research and involved the modelling of the EAPP wholesale market in AMIRIS, an agent-based model developed by the German Aerospace Agency. There were no copyright issues in accessing the model and its source code as it is an open-source model provided under a creative commons license

However, the modelling required input data to be collected from online secondary sources and gatekeepers. The secondary data was mainly the generation expansion plans of the five EAPP countries under study. The data collection process targeted gatekeepers who had information regarding the electric power networks of Kenya, Uganda, Ethiopia, Tanzania, and Rwanda. The gatekeepers of the information were emailed and followed up by phone and other electronic means over 2023. A gatekeeper request letter was sent to respondents with access to the necessary data for the simulation. The main targets were persons working in management in the regulators, utilities, and at the EAPP secretariat. The data used to develop the model inputs was either publicly available or authorised for sharing by gatekeepers.

Data was collected from individuals and references available online. This included a regulator at the Kenyan Electricity and Petroleum Regulatory Authority (EPRA), a manager at a private utility in Kenya, two regulators at the Ugandan Electricity Regulatory Authority

(ERA), a manager at the Eastern African Power Pool Secretariat, a manager at an Ethiopian utility, and a manager at a utility in Tanzania. The secondary data collected included the most recent power masterplans of the five countries, describing the generation plants, expected regional transmission lines, costs of generation, load profile of the countries, and general data on the EAPP.

The source code of AMIRIS was adapted to the EAPP condition by inputting the time-series data of the various renewable resources and the combined and anonymised powerplant data from the five EAPP countries. These were combined according to the generation technology per country. The specific powerplant data were thus modified to powerplant cluster data per technology per country.

The model was run with two simulations of an EAPP day-ahead market for the year 2025. The results were analysed to generate descriptive statistics and respond to the second research question. A fifteen-minute presentation to be used as a basis for presenting the simulation process and assumptions to the key informants was prepared in PowerPoint.

The qualitative phase involved interviewing 11 key informants to provide feedback on the model assumptions, results, and appropriateness for the Eastern African context. These key informants volunteered to participate in the research. The informants were allowed to exit the interview process at any time. Emailed requests for interviews were sent to the informants with a description of the study. The informants were informed of the nature of the research in advance, presented with quantitative findings at the beginning of the research, and provided with the questionnaire in advance.

Each interview lasted an hour and was conducted using a mixture of physical face-to-face interactions and virtual interviews via Zoom. The informants were allowed to venture into

themes that were not envisioned in the interview guides and were relevant to responding to the research questions. The interviews were recorded with the consent of the informants in audio files. These were then transcribed in MS Word with concurrent proofreading. The informants' details were anonymised, and each informant was assigned a code to conceal their details. The interviews continued until saturation was reached, with 11 key informants.

Recurring themes from the interviews were identified and used to enrich the findings of the quantitative analysis. The documentation of the findings and new and recurring themes together with the earlier quantitative findings was undertaken.

Data analysis was conducted using Excel and SPSS for the quantitative part and was enriched by the qualitative analysis findings. Research findings and recommendations for future research and practice were then drawn.

3.6.2. Ethical Assurances

The data collection process did not store the names of the individuals who responded with the data necessary for the research and sort consent to use the information provided in the research. This practice was also applied for the validation stage of the model when administering the semi-structured questionnaires to ensure the anonymity of the key informants.

The bulk of the study was undertaken within the framework of computer-based simulations run under the adapted AMIRIS wholesale market model. This focuses more on ethical matters related to data handling and copyright issues related to the AMIRIS model. The simulation will involve the researcher directly and the AMIRIS agent-based model of the German aerospace agency (DL), which is provided on an open-source basis. Researchers are

free to access the model and its source code and modify it as necessary, with the understanding that any related new improvements are to be provided to the general research body free of any charges. This research is undertaken for academic purposes and will not result in commercial software.

The eligibility criteria were adhered to for the validation process. The included informants had at least five years of experience in the electricity sector in Eastern Africa, with a preference for regulators and electricity market participants. Staff at a managerial level were the preferred respondents because of their expected broad knowledge. Any respondent who was a non-expert or who was not consenting to participate in the validation process was excluded. Persons with mental disabilities and those unable to provide consent for themselves were not included in the study.

The validation process applied to semi-structured face-to-face or virtual meetings was used to interview key stakeholders in Eastern African electricity markets. These included knowledgeable private and public participants in various markets. The sampling of stakeholder views and data followed purposive sampling to ensure that the most experienced and relevant respondents were interviewed. Participants were identified from regional regulators, private power companies, and power utilities. They were called and emailed with a request for consent for an interview with the topics and university research approval documents were sent in advance. The interviewees were reminded of their right to end the interview at any point and to request that any of the information and data they provide be expunged from the report.

CHAPTER 3.7. SUMMARY

This section describes the research approach and design, including the sampling approach, instrumentation of research tools, operational definition of variables, study procedures and ethical assurances, and approach to data collection and analysis.

3.7.1. Research Approach and Design

This study's research structure follows a mixed-methods approach with a sequential explanatory design (Othman et al., 2020; Toyon, 2021). The research undertook a quantitative process through simulation, followed by a qualitative process to explain, question, and contextualise the quantitative findings using key informant interviews guided by a semi-structured questionnaire.

An explanatory sequential design was undertaken, beginning with a quantitative simulation to generate system-level insights into the dynamics of the EAPP wholesale market. These insights and patterns are non-intuitive and cannot be empirically observed. The simulation provides system-level findings that direct and focus on qualitative analytics, particularly because the EAPP wholesale market is not yet active. The qualitative step then develops in an explanatory manner, with key informant interviews providing context, further interpretation, and analysis of the findings. A purely quantitative approach would not ground the research in the context, whereas a purely qualitative approach would result in a general broad feedback void of the system-level nuances that the simulation provides.

Epistemologically, the quantitative approach through simulation attempted to model the EAPP wholesale market and explain its workings under high VRE in a data-driven, replicable model. The model and simulation results are synthetic, as they are based on a model

built on assumptions and not reality. This allows for the modelling of complex systems but may also lead to overlooking nuances (Beese et al., 2019). The qualitative process aimed to gather information and understand subjective experiences localised to the EAPP from expert perspectives, further explaining why phenomena are observed. While this offered deeper insights, it also exposed the research to informant bias (Pahwa et al., 2023).

This study employed methodological triangulation through complementarity- and discrepancy-driven analyses. The simulation results and key informant interviews were treated as different explanations for or evidence of the effects of VREs on the EAPP market. The integration of the two approaches was viewed at three levels: study design, methods, and interpretation and reporting, which is consistent with the framework in the literature (Fetters et al., 2013). At the interpretation and reporting level, a narrative approach was adopted with a description of the quantitative and qualitative findings by theme (Guetterman et al., 2015), highlighting points of alignment and departure.

Simulation Research Design and Agent-Based Modelling

Three approaches to simulation research design have been identified: discrete events, system dynamics, and agent-based simulations (Dooley, 2002). Agent-based simulation was chosen for this study because it best represents the complex interactions in a wholesale electricity market, with different agents learning after every trade (Ringler et al., 2016). Agent-based models focus on participants as discrete entities, whereas system dynamics models focus on variables and events. This makes agent-based models particularly relevant to wholesale deregulated markets (Shinde & Amelin, 2019).

Agent-based modelling and simulation (ABMS) models an electric power system with various agents and institutional frameworks, including their learning behaviour, decision rules,

and relationships with other agents. These agents make autonomous decisions that lead to the evolution of the market without the intervention of the modeller (Ringler et al., 2016). They bid for supply and demand, with the resultant marginal price determining trade. This approach allows the analysis of electricity markets in aspects such as asymmetric information, learning, externalities, and strategic interactions, better mimicking real-world markets than equilibrium or system dynamics approaches. This study adapted the Java-based AMIRIS model, which was developed by the German Aerospace Agency (Klein, 2020; Reeg et al., 2020; Schimeczek et al., 2023).

The modelling and simulation process followed the steps outlined in Figure 3-2 (Yin & McKay, 2018): building on the research problem and purpose, data relevant to the EAPP were collected; a conceptual model was developed; and the AMIRIS model was verified, validated, and run with two main and three sensitivity scenarios.

3.7.2. Population and Sample of Research

The study sample for the quantitative component comprised five EAPP member states (Kenya, Uganda, Tanzania, Ethiopia, and Rwanda), selected based on their direct physical interconnection and the availability of generation expansion plan data. This criterion allowed for the simulation to be performed without having to build in assumptions for power flows in an intervening country grid not included in the sample

The qualitative sample comprised 11 key informants selected through purposive sampling to ensure that the most experienced and relevant respondents were interviewed. Eligibility required a minimum of five years of experience in the Eastern African electricity sector, with a preference for managerial-level staff at regulators, utilities, and generators. The

informants were drawn from Kenya, Uganda, Tanzania, and Ethiopia. No female respondents were identified within the pool of eligible key informants, which is a limitation in terms of gender representativeness. Thematic saturation was achieved at 11 interviews, below the initially projected 20, but consistent with saturation benchmarks in expert interview studies (M. Hennink & Kaiser, 2022; Yang et al., 2022).

3.7.3. Instrumentation of Research Tools

The research involved the use of a simulation based on a model and semi-structured questionnaire.

3.7.3.1. The AMIRIS Model

This study used AMIRIS (Agent-based Market model for the Investigation of Renewable and Integrated energy Systems) version 2.0.0-alpha.33, developed and maintained by the German Aerospace Center (DLR). It is an open-source tool that runs on the Java platform, based on the Framework for distributed Agent-based Modelling of Energy systems (FAME), and is available on GitLab . AMIRIS simulates the operation and trading of power plants in a market zone with a resolution of 1 h, models market behaviour under uncertainty and has processing speeds of less than 1 min per run.

AMIRIS focuses on the business-oriented decisions of actors in wholesale electricity systems. Agent decisions are influenced by marginal prices, support instruments such as feed-in tariffs, market power, and information availability (Deissenroth et al., 2017; Nitsch et al., 2021). The model was adapted from its German configuration to reflect the EAPP context by modifying *scenario* and *contract* YAML files and inputting country-specific time-series data. The model allows for the direct entry of multiple parameters via a notepad into the

'*scenario.yaml*' and '*contract.yaml*' files, allowing for reproducibility, transparency, and accuracy, with inputs and outputs in the '.csv' format (Klein, 2020; Reeg et al., 2020).

Two simulations were run for the year 2025: a base case reflecting operational and under-construction generation capacity (19,575 MW) and a high VRE case incorporating additional planned solar, wind, geothermal, and battery storage capacity (26,121 MW). Power plant data were assembled from publicly available national generation expansion plans and supplemented by gatekeeper data from regulatory authorities, utilities, and the EAPP Secretariat.

Three sensitivity scenarios were also run to extend the quantitative analysis and test specific operational and market design assumptions that emerged from the key informant interviews. The medium-VRE scenario was constructed by setting the 13 agents that differed between the base and high-VRE cases to their exact midpoint, adding +2,773 MW of new capacity, and placing the scenario precisely halfway between the two main cases in terms of total installed capacity.

The geothermal must-run scenario assigned dispatch priority to geothermal plants regardless of the market clearing price, isolating the effect of baseload dispatch commitments on pricing and VRE headroom under a high-VRE configuration.

The optimal VRE capacity scenario identified the level of additional VRE capacity at which the annual mean market price crosses zero, expressed through a scaling parameter, α .

3.7.3.2. Data Inputs

The demand time series for all five countries were derived by scaling Kenya's 2023 hourly demand profile to each country's projected 2025 peak demand, as guided by national least-cost power development plans (ERA Uganda, 2021; MoE, 2022; MoE Tanzania, 2020; Rwanda Energy Group, 2022; USAID Power Africa, 2021). Solar resource data were obtained from the SolarGIS/World Bank Global Solar Atlas using a reference site at Eldoret, Kenya, which is assumed to be representative of all five countries given their equatorial proximity (SolarGIS & World Bank, 2024).

Wind time series were derived from the global wind atlas (DTU & World Bank, 2024) for two sites: Loiyangalani in Marsabit County (Kenya) for Kenyan wind plants, and the Oromia region of Ethiopia for plants in the remaining countries. Hydropower was modelled as a run-of-river plant using the AMIRIS generic German time series, given the unavailability of plant-specific reservoir data. Bioenergy was similarly modelled using the default AMIRIS time-series. International LNG and HFO prices for 2023 were adopted as proxies for 2025 pricing, given their inherent volatility.

3.7.3.3. Model Validation

Verification and validation of the model were conducted through code inspection, a review of the model's existing validation literature, face validation by subject matter experts, and input-output analysis. For external quantitative validation, the model was run against actual Kenyan grid data for the year 2023; the total energy dispatched in the simulation deviated by only 0.58% from the figures reported by the regulator, Energy and Petroleum Regulatory Authority (EPRA), establishing that the model replicates real-world dispatch with sufficient accuracy to support the EAPP simulations.

The qualitative phase further tested the model's assumptions and outputs against expert experience. Both verification and validation are distinct processes: verification confirms that the model performs as intended, whereas validation confirms that it adequately represents the real system being modelled.

3.7.3.4. Semi-Structured Questionnaire

The semi-structured questionnaire was designed to validate the AMIRIS model and its simulation results in the EAPP context. It was structured around three themes derived from the quantitative dependent variables: electricity pricing, dispatch of power plants, and stability of supply. Prior to each interview, key informants were provided with the questionnaire and were given a 15-min presentation of the quantitative findings. The interviews were open to additional themes that informants considered relevant, which proved important in surfacing issues not captured by the model. These included transmission constraints, ancillary services, and political economy considerations.

3.7.4. Operational Definition of Variables

The quantitative component of the research was structured around a single independent variable, VRE penetration in the EAPP grid, and two primary dependent variables: electricity pricing and the dispatch levels of power plants. Electricity pricing is operationalised as the hourly wholesale electricity price produced by the AMIRIS market-clearing mechanism, measured in EUR/MWh. Dispatch is measured in full-load hours, representing the volume of electricity produced by each plant relative to its maximum theoretical output (Tumiran et al., 2021).

The study also identifies moderating variables, including the merit order of dispatch and the regulatory framework, as well as mediating variables such as the flexibility of generation technologies and the level of interconnection between countries. Control variables include fuel prices, CO2 pricing, and demand profiles, which are held constant across the two main scenarios to isolate the effect of VRE penetration. Countries may prefer to assign first-right-of-dispatch to locally installed technologies, such as geothermal and hydro, given their strategic investment nature; however, in this simulation, dispatch priority was not assigned to any technology outside of marginal pricing considerations.

3.7.5. Study Procedures and Ethical Assurances

The study was approved by the UNICAF University in Zambia Ethics Committee on January 31, 2023, prior to data collection. The AMIRIS model is published under a Creative Commons open-source licence, with no copyright restrictions on use or adaptation, provided that modifications are made available to the research community on a non-commercial basis. All data obtained from gatekeepers were either publicly available or explicitly authorised for research use. Gatekeeper engagement was conducted in 2023 through email, telephone, and electronic follow-up, targeting management-level staff at regulatory authorities, utilities, and the EAPP Secretariat.

The key informants in the qualitative phase were provided with the research description and questionnaire in advance. They were presented with the quantitative findings at the beginning of each interview and were guaranteed the right to withdraw at any stage. Interviews were recorded with consent, transcribed, and anonymised through numerical coding. The eligibility criteria for informants required at least five years of experience in the Eastern African electricity sector; persons who were non-experts, non-consenting, or unable to provide informed consent were excluded. Qualitative data were analysed through inductive thematic coding, resulting in eight consolidated themes that combined quantitative-derived and organically generated thematic codes.

The integration of quantitative and qualitative findings occurred at the interpretation and reporting levels, consistent with the framework applied in comparable mixed-methods research (Ivankova et al., 2006; McCrudden & McTigue, 2019). Integration strategies included joint displays connecting the three quantitative dependent variables (electricity pricing, dispatch of power plants, and stability of supply) with the eight qualitative themes derived from

the key informant interviews, as well as narrative integration that drew qualitative explanations through the lens of the simulation findings. Points of alignment and departure between the two sets of findings were documented.

Taken together, the five simulation scenarios, qualitative interviews with 11 experienced sector practitioners, and integrated mixed-methods analysis provide the methodological basis for responding to all three research questions: the current state and structural limitations of electricity trade in the EAPP, the effects of a short-term wholesale market on pricing and dispatch under varying levels of VRE penetration, and the broader implications for market design and policy in Eastern Africa.

CHAPTER 4 RESEARCH FINDINGS

CHAPTER 4.1 : INTRODUCTION

This chapter presents the quantitative and qualitative findings of the research in response to the three research questions. The chapter is organised to first establish the trustworthiness of the data. The data used in the simulation came from published sources in the five respective countries. The main source was the generation expansion plans of the countries, available as of 2023. This ensured that the input data were legitimate. The section also details the key assumptions of the modelling and simulation processes.

Section 2 presents the results of the quantitative modelling process and the qualitative key informant interviews. Section 3 evaluates the findings against each research question. The quantitative simulation findings and the qualitative insights from 11 experienced sector practitioners are combined to respond to the research questions. The chapter concludes with a summary of the findings and their implications for electricity market design and VRE integration in the EAPP.

The first research question was how is electricity traded globally and in Eastern Africa? This was addressed through comparing key informant interviews with the literature. The current state of electricity trade in the EAPP is characterised by long-term bilateral power purchase agreements between utilities. The EAPP short-term market is not yet operational. The key informant findings confirm that the EAPP is about to launch a day-ahead market. Institutional and technical preparatory work is ongoing. The findings were evaluated against the experience of similar power pool markets, with comparison to the Southern African Power Pool (SAPP), with which the EAPP is expected to interconnect.

Second, how would the introduction of more variable renewable energy affect wholesale electricity markets in Eastern Africa? This was addressed through the AMIRIS agent-based simulation. Two main scenarios were run for the year 2025: a base case with the generation capacity expected to be operational by 2025, and a high-VRE case based on national generation expansion plans. The simulation results were analysed in terms of their effects on electricity pricing, dispatch and utilisation of power plants, value of renewable energy support instruments, fuel consumption and CO₂ emissions, and the economics of battery storage.

Three sensitivity scenarios were run to test specific market designs and operational assumptions. They included (1) a medium VRE scenario constructed at the exact midpoint of the base and high VRE capacity additions, (2) a geothermal must-run scenario that assigned dispatch priority to geothermal plants regardless of the market-clearing price, and (3) an optimal VRE capacity scenario that identified the level of additional VRE at which the annual mean market price crosses zero. The sensitivity analysis findings are presented alongside the main results of the VRE penetration levels.

The third research question was how accurate were the adapted model and simulation findings for the Eastern Africa Power Pool? This was addressed through the quantitative external validation process and the qualitative key informant interviews. The model was validated using actual Kenyan grid data. A scenario for Kenya in 2023 was run and compared with actual grid data. A deviation of 0.58% in the total dispatched energy from the statistics reported by the Kenyan regulator, EPRA, was observed. In the qualitative process, the model assumptions and simulation results were presented to key informants for their assessment. Eight themes emerged from the qualitative feedback coding process. These included electricity pricing, dispatch of power plants, stability of supply, model assumptions, EAPP market

structure and operations, generation technology considerations, transmission capacity considerations, and the political economy of the EAPP. Qualitative feedback added the EAPP context to the quantitative findings and the validation of the instrument.

The chapter also examines the alignment and points of departure between the quantitative and qualitative findings. A joint display approach is used to map the three quantitative dependent variables against the eight qualitative themes. A section situating the qualitative findings within the theoretical framework of the study is also included. This section analyses how the findings from the key informant interviews reinforce or challenge theory.

CHAPTER 4.2: TRUSTWORTHINESS OF DATA

This research involved the acquisition of data related to power plants that were planned and installed in the five East African markets of interest. These data were gathered from the official national plans of Ethiopia, Kenya, Uganda, Tanzania, and Rwanda available at the time of the research (ERA Uganda, 2021; MoE, 2022; MoE Tanzania, 2020; REG Rwanda, 2019; USAID Power Africa, 2021). These reports include data on operational and planned projects up to the year of study of 2025. These data were used to select the base and highly renewable cases. The trustworthiness of the data in these plans was guaranteed as they were official government documents. However, there may be variations in the latest versions of these generation expansion plans, as the utilised documents were restricted to those available as of the year 2023. In the last two years, there may have been updates; however, the research was conducted until 2023 for uniformity, considering that these documents had projections well beyond 2025, which is the study reference year for the research simulations.

Data on power plants in various countries were combined and anonymised in technology pools, such as Kenya wind and Tanzania solar. The data on the resource quality of VRE plants were retrieved from the Global Wind Atlas and the Global Solar Atlas. Using data from these sources, timeseries values for 8670 hours of the year were generated. The AMIRIS generic timeseries for hydroelectricity and bioenergy in Germany was adopted as the timeseries for hydroelectric and bioenergy plants in eastern Africa. Although this is likely to cause deviation from the actual regime of each of the different individual power plants, it is not expected to lead to significant deviation from actual averages. The timeseries used for the simulation of various technologies is an annual average and does not capture any extreme weather events that may occur each year.

CHAPTER 4.3: RESULTS

The results of the study are organised and presented below in accordance with the research questions. The three research questions addressed were as follows: (1) How is electricity traded globally and in Eastern Africa? (2) How would the wholesale electricity market in Eastern Africa be affected by the introduction of variable renewable energy? (3) How accurate are the adapted model and simulation findings for the Eastern African Power Pool? The section ends with a summary of other comments made by key informants related to the EAPP.

4.3.1. RQ1: How is electricity traded globally and in Eastern Africa?

This research question was addressed through a literature review and responses to key informant interviews. The responses of the key informants regarding how electricity is traded in the EAPP are summarised as follows:

Electricity trade in the EAPP was reported to be through PPAs and bilateral trade. However, it was noted that in the future, there will be a hybrid of bilateral and day-ahead markets. These two markets will be allowed to operate simultaneously in the EAPP, allowing both legacy and new bilateral contracting, as well as wholesale market trade of energy. It was noted that currently, KE and UG trade through a power exchange at a fixed tariff, while KE and ET trade through a bilateral PPA based on a fixed take-or-pay tariff. Rwanda, Burundi, and the DRC share hydroelectric facilities in the Ruzizi cascade, and Rwanda and Tanzania share the Rufiji hydropower plant.

The EAPP market was noted to be under development and would follow the SAPP model. The pool would eventually be voluntary for private and public organisations to

participate with their non-firm energy. The EAPP would initially launch with a day-ahead market.

The EAPP would have a market and a pool. The EAPP secretariat would transform into the independent system operator that would run the pool. It was expected that there would be a SCADA system and market operation software in place by the end of 2024. Furthermore, parallel work was being undertaken on the below, among others.

Operational works: The EAPP operations committee is undertaking works to enable the operation of the pool. This includes supporting the completion of transmission lines and ensuring compliance with the regional grid code. The synchronisation of the KE, UG, TZ, and ET electricity grid systems has not yet been performed. The pool currently allows state-owned utilities to participate, and the involvement of the private sector is under consideration.

Market rules: The market rules for the EAPP were under development by the market committee. The draft legal documentation was expected to be ready by mid-2024. These are important because of the multiple interconnections that were in place during the year. These include interconnections with KE, UG, TZ, ET, SUD, and RW.

The EAPP trading platform: The trading platform of the EAPP is under development, and an EAPP day-ahead market is expected to launch in 2026.

The regional regulator: The regional regulator, the Independent Regulatory Board (IRB), was established and is based in Uganda, with capacity-building training ongoing.

Kenya is scheduled to introduce a new market structure with the possibility of shorter-term trading of electricity, bulk supply, and wheeling of power. The country is currently developing The Energy (Electricity markets, bulk supply, and open access) regulations 2024 that would enable these changes in the market structure. Uganda was also reportedly further opening its market with the implementation of the Ugandan Energy Act of 2022.

4.3.2. RQ2: How would the introduction of more variable renewable energy affect wholesale electricity markets in Eastern Africa?

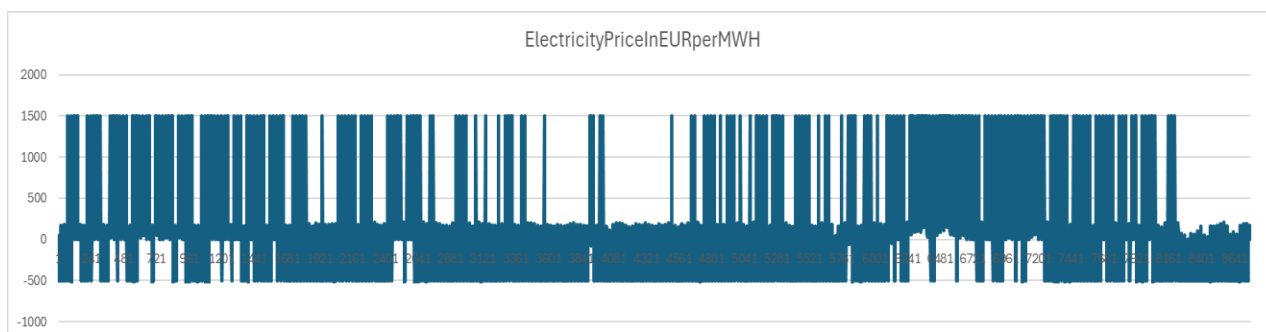
The AMIRIS electricity market model was used to run day-ahead market simulations to answer this research question. The simulation process reviewed various aspects of the electricity market under normal and high levels of renewable energy penetration. The simulation results showed the effects on pricing, the effect on the market value of the support instruments for renewable energy, the awarded energy for conventional and renewable plants, the effect on CO₂ emissions, and the value of battery storage in the Eastern African grid. The following section presents the assumptions of the simulation and the simulation results for these specific data points.

4.3.2.1. Electricity Prices

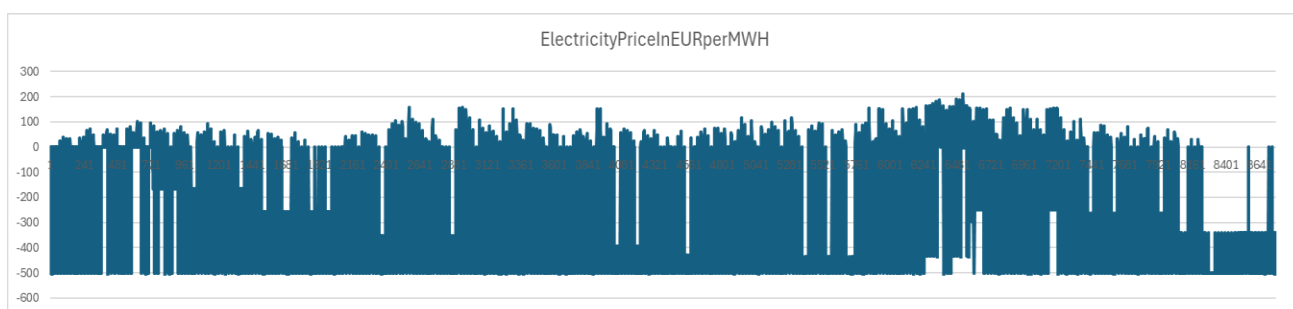
Figure 4-1 and **Figure 4-2** show the variation in the pricing of electricity in the Eastern Africa Power Pool considering the base case and the high-VRE case. In the base case, there are numerous instances in which the price overshoots the market maximum price of EUR 1500/MWH for 556 hours in a year. This implies an inability to supply power at peak demand levels; thus, the maximum price is charged. The price remains above zero, on average, at an average price of 67.5 EUR/MWH for the year 2025. The price drops to the maximum negative price value of – 500 EUR/MWH for 1889 hours in the year 2025. Overall, the prices are negative for a total of 1979 hours in a year.

Figure 4-1

Electricity prices in the EAPP in 2025 in the base scenario

**Figure 4-2**

Electricity prices in the EAPP in 2025 in the high varying RE scenario



In the high-varying renewable energy scenario shown in **Figure 4-2**, the maximum price of EUR 1500/MWh is not achieved over the entire year. This implies the ability to fully supply power at peak demand levels; thus, the maximum price is not charged. The average price remains below zero, at an average price of -295.57 EUR/MWh for the year 2025. The price drops to the maximum negative price value of – 500 EUR/MWh for 2451 hours in the year 2025. Overall, the prices are negative for a total of 6792 hours (an alarming 77% of the time) in a year. **Table 4-1** summarises the impact on pricing for the base and high VRE scenarios.

Table 4-1*Table with the impact of high VRE in the EAPP*

	2025 Base Scenario	2025 High Renewable Scenario
VRE ⁵ MW Capacity Penetration (%)	5%	24.2%
VRE ⁶ MWH Energy Penetration (%)	7.9%	20.5%
Average Price EUR/MWh	67.5	-295.57
Total Energy (MWH)	61,499,095	62,569,826
Dispatch System Cost (EUR)	3,198,766,839	2,779,417,034
Per Unit System Dispatch Cost (EUR/MWH)	52.01	44.42
Instances of under supply at peak (Hrs)	556	0
Instances of (-500 condition) Market negative prices (Hrs)	1,889	2451
Instance of negative market prices (Hrs)	1979	6792

The electricity price collapses with peak prices in the base case averaging between 932 and 841 EUR/MWh. In the high-VRE case, the peak prices average between 10 and below 0 EUR/MWh. The 250 MWh battery installation in the high-VRE scenario helps shift excess daytime generation into the evening ramp. The price and demand duration curve, the diurnal demand profile, the monthly prices, and demand quartile sensitivity are shown in **Figure 4-3**, **Figure 4-4**, **Figure 4-5**, and **Figure 4-6**, respectively.

⁵ Statistic relating to Wind and Solar only

⁶ Statistic relating to Wind and Solar only

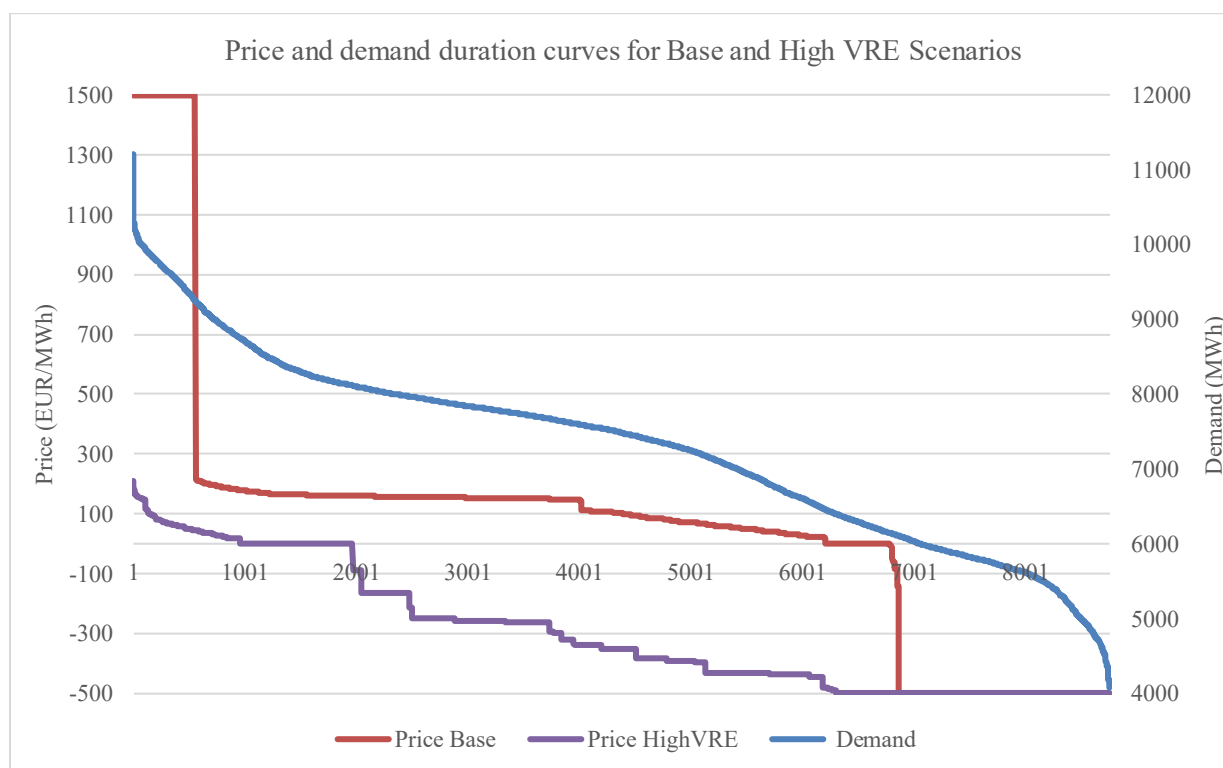
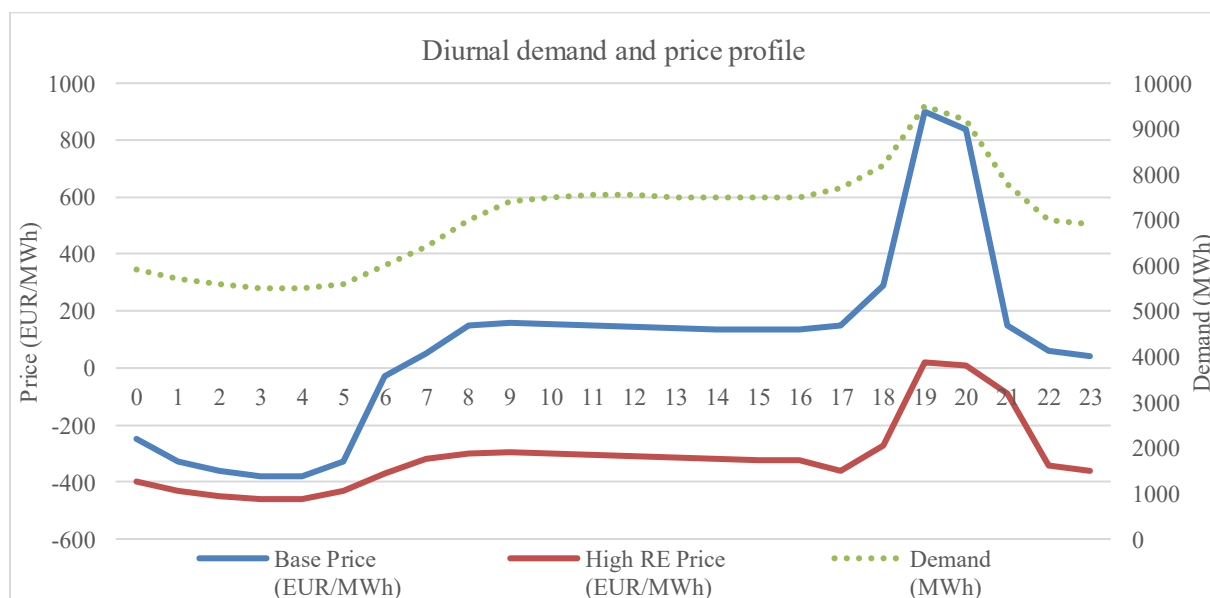
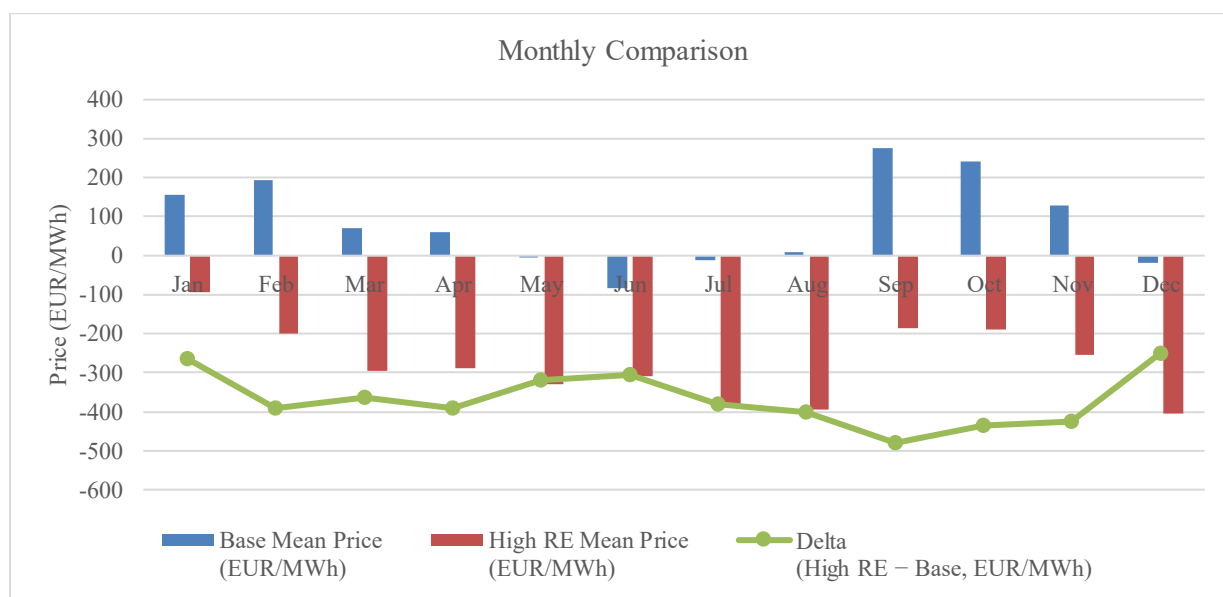
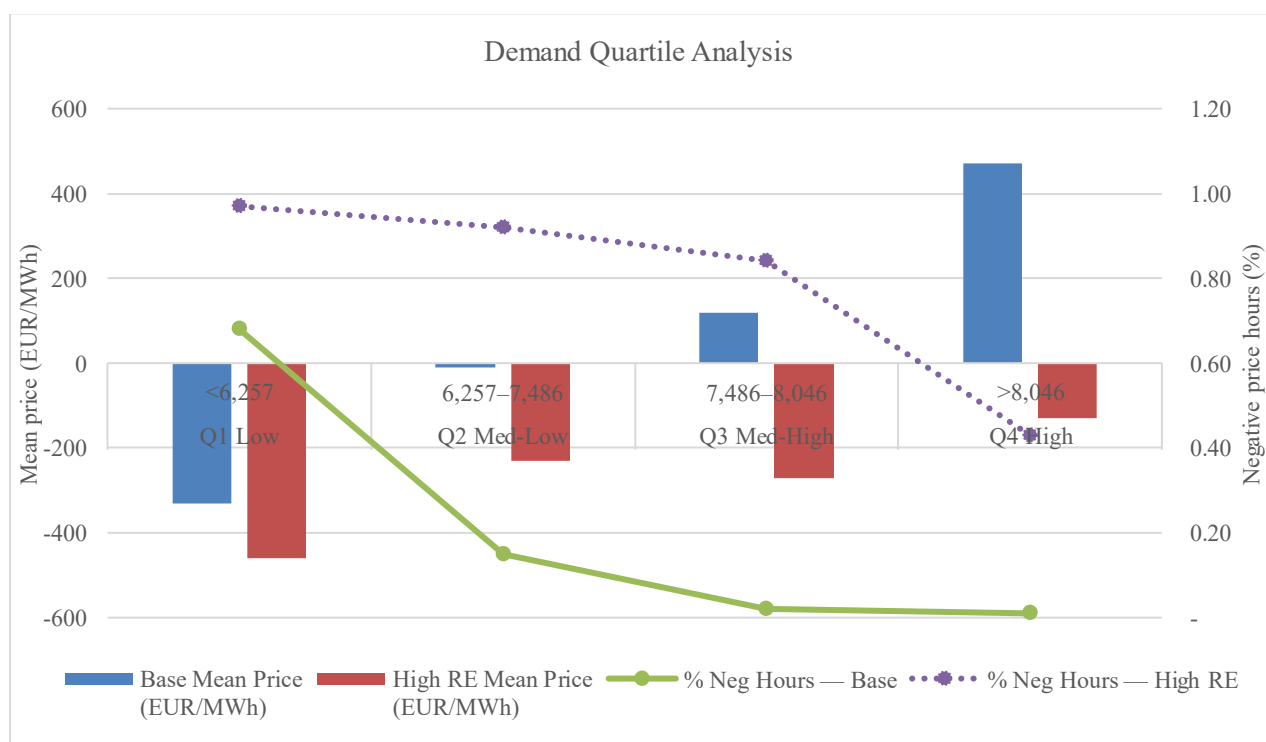
Figure 4-3*Price and demand duration curves***Figure 4-4***24-Hourly price demand and price profiles*

Figure 4-5*Monthly price comparisons***Figure 4-6***Demand sensitivity*

4.3.2.2. Energy Awarded to Power plants

Varying Renewable Power Plants

The energy awarded to various renewable energy plants in the base case is 52.07 TWh, or 85% of the awarded energy, as depicted in **Figure 4-7**. This value increases to 61.07 TWh or 92% of the awarded energy in the high-RE scenario, as shown in **Figure 4-8**. All the energy in the base scenario is awarded along with energy from new various RE plants in the high-VRE scenario. When wind and solar power plants are considered separately, they contribute to 5% and 24% of the installed capacity in the base and high-VRE cases, respectively. The two technologies contribute 7.9% and 20% of the energy dispatched in the base and high-VRE cases, respectively.

Figure 4-7

Awarded Energy to varying RE plants in the base scenario

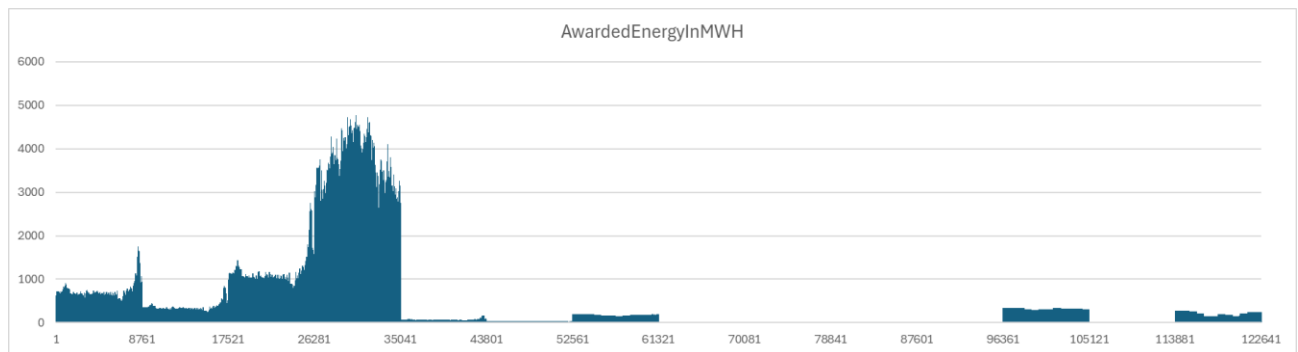
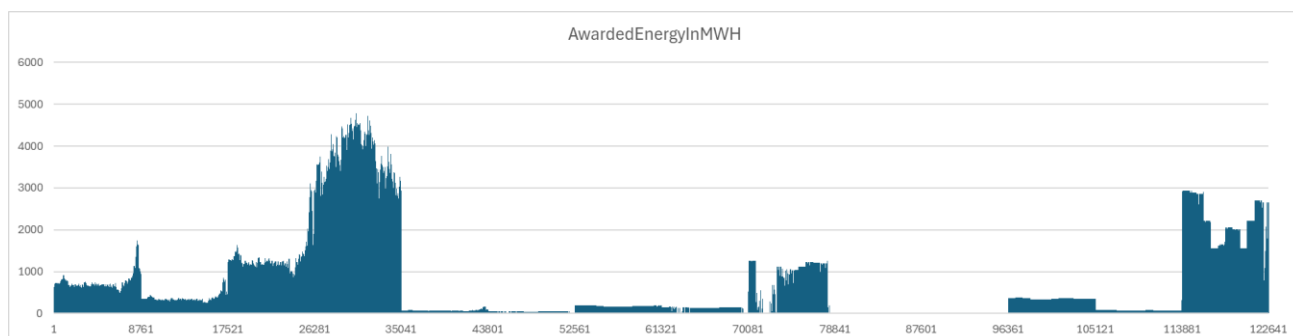


Figure 4-8

Awarded Energy to varying RE plants in the high varying RE scenario



Value of Support Instruments

The value of the renewable RE support instruments is positive, peaking at 300 EUR/MWH in the base scenario, as depicted in **Figure 4-9**. The market value of the RE support instruments then collapses to negative values, bottoming at -450 EUR/MWH, as depicted in **Figure 4-10**.

Figure 4-9

Market value of support instruments under base scenario

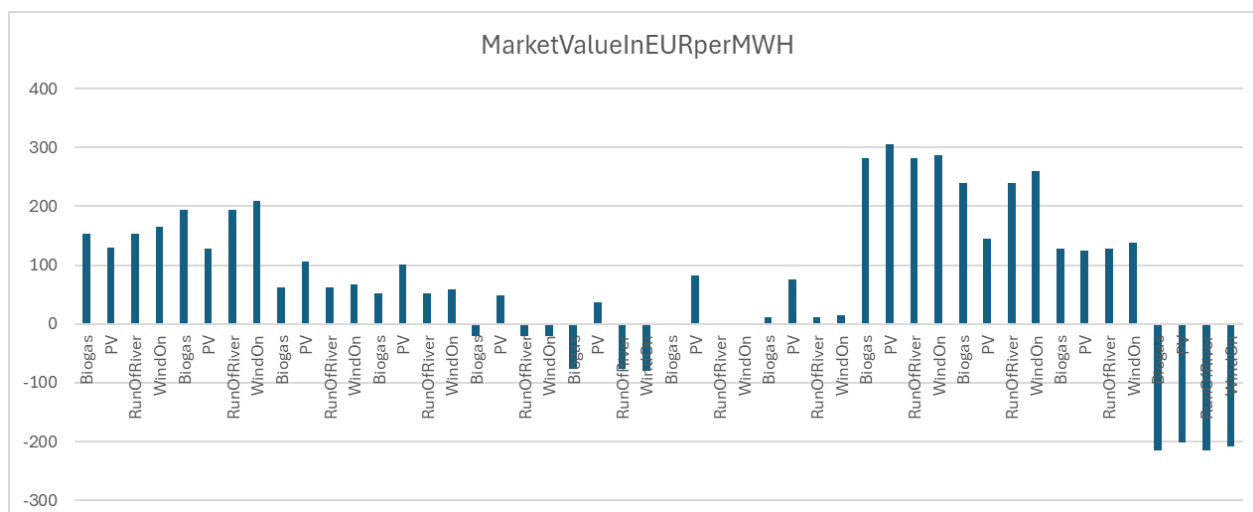
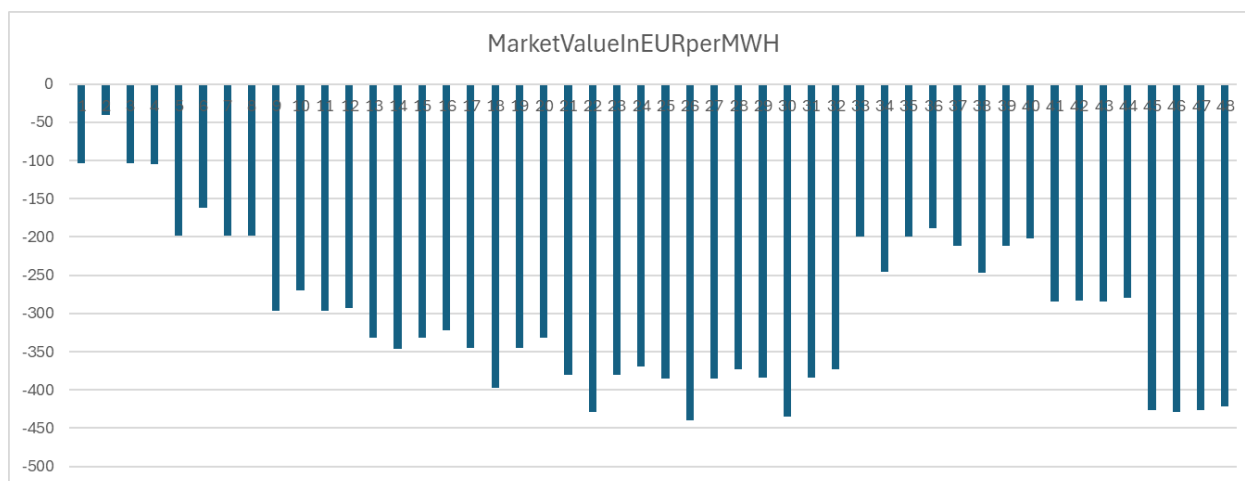
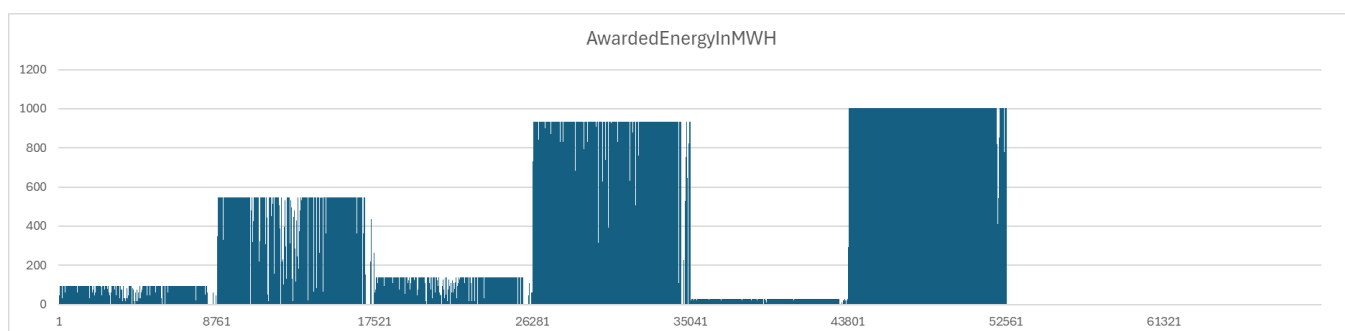


Figure 4-10*Market value of support policies under High RE scenario***Energy Awarded to Conventional Plants**

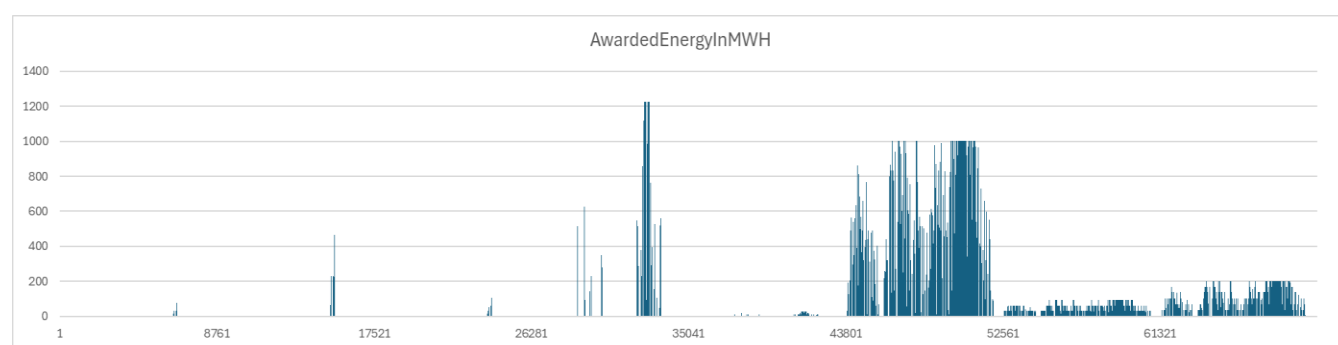
Conventional power plants (HFO, LNG, and geothermal) exhibit strong levels of energy awarded in the base scenario, representing 8.4 TWh or 14% of the awarded energy. This is supported by the strong dispatch of geothermal plants and the relatively high dispatch of LNG plants. **Figure 4-11** depicts this scenario.

Figure 4-11*Awarded energy of conventional plants in the base scenario*

The high-VRE scenario shows a near-total halt in dispatch from conventional plants, especially HFO plants. The introduction of new geothermal capacity is shown. The dispatch from conventional plants drops by 93%, representing 1% of the awarded energy. This is depicted in **Figure 4-12**. The Tanzanian LNG increases by 300 MW with a 100 EUR/MWh markup. The plant only dispatches when prices are high, which only occurs a few times in the high-VRE scenario.

Figure 4-12

Awarded energy of conventional plants in the High RE scenario



Fuel Consumption of Conventional Plants

The fuel consumption of conventional power plants decreased by more than 93% from the base scenario to the high-VRE scenario, as presented in **Table 4-2**. The CO₂ emissions from conventional plants decreased by 98% in the high RE scenario compared to the base scenario, as depicted in **Figure 4-13** and **Figure 4-14**.

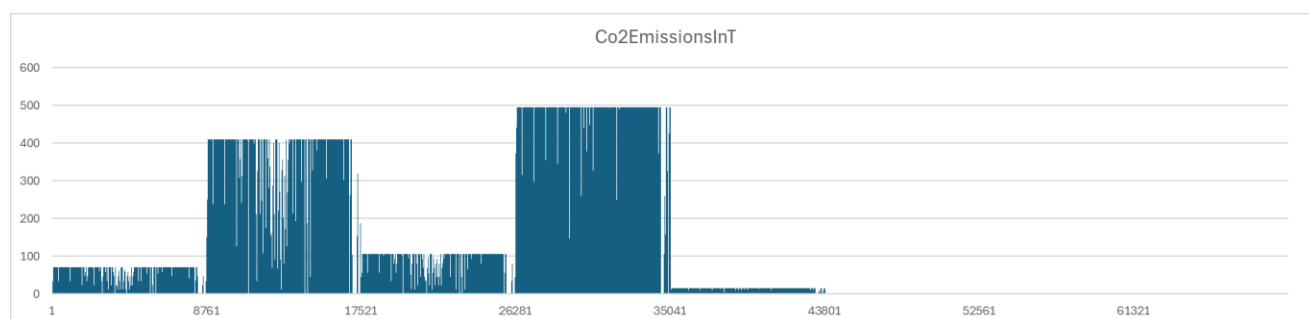
Table 4-2

Change in energy awarded and fuel consumption for conventional plants

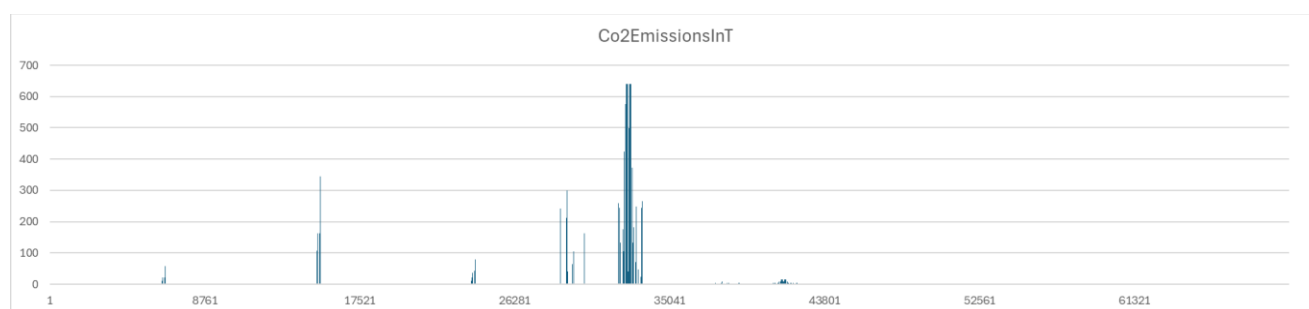
	Base Scenario	High RE scenario	Percentage Variation
Awarded Energy (MWH)	8,418,330	582,986	-93.07%
Fuel Consumption (MWH)	22,127,348	1,462,363	-93.39%
CO2 Emissions (Tonnes)	1,861,655	37,297	-98.00%

Figure 4-13

CO2 emissions of conventional plants in the base scenario

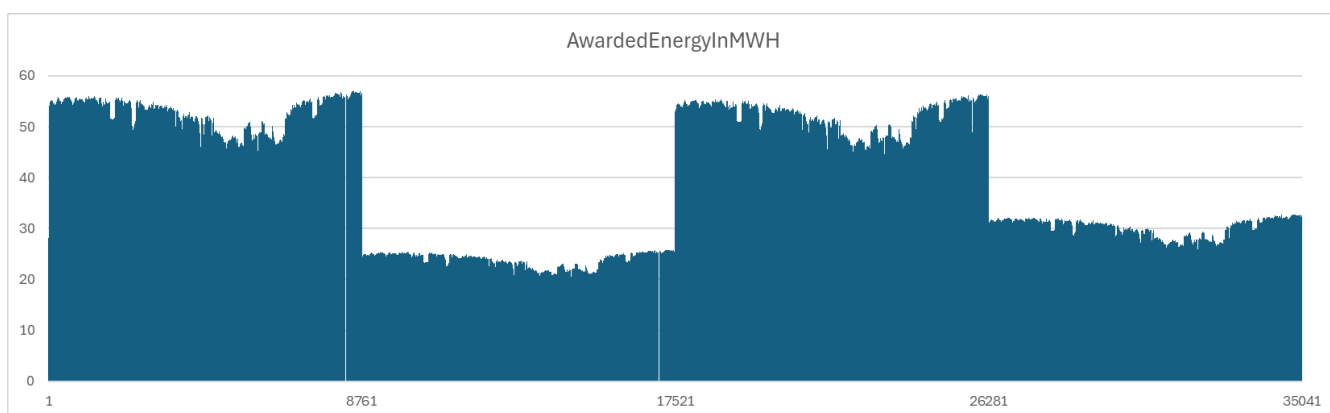
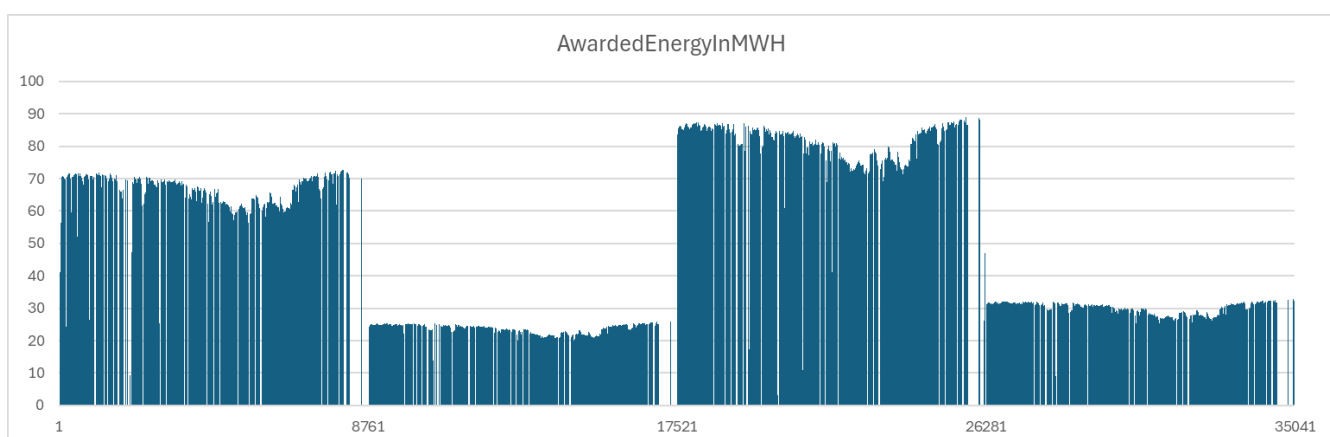
**Figure 4-14**

CO2 emissions of conventional plants in the business-as-usual scenario



Energy Awarded to Biomass Plants

Energy from biomass represented 1.01 TWh or 2% of the energy awarded in the base scenario, as depicted in **Figure 4-15**. This amount of energy awarded was reduced by 32% to 0.32 TWh or 1% of the awarded energy in the high-RE scenario, as depicted in **Figure 4-31**.

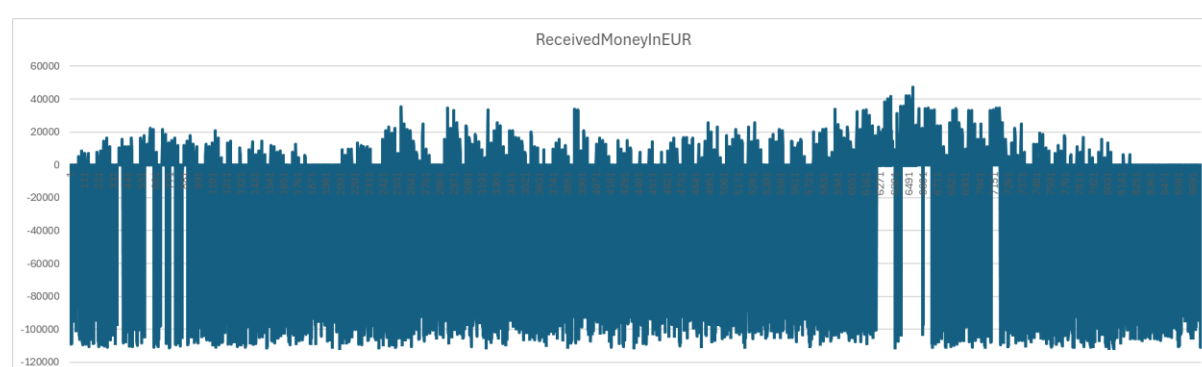
Figure 4-15*Awarded Energy for Biomass Plants in the base scenario***Figure 4-16***Awarded Energy for Biomass Plants in the high RE scenario***Economics of Battery Storage Plant**

The base scenario does not include any grid-scale battery storage projects. The high-RE scenario considers battery storage systems added to the EAPP grid of the five countries. A single 250 MWh battery system is added to the grid, which is then awarded 157 GWh or 0.25% of the total awarded energy. The battery system required 758 GWh to charge it, while it was awarded 600 GWh in energy discharge to the grid.

The results for the money received by the battery storage facility operator show that the facility will not be called upon to produce as often and would overall be in a negative cash position at the end of the year. The battery operator will have a debt of EUR 193 million as a net cost of energy consumed from the grid for charging versus the income from discharging to the grid. **Figure 4-32** shows the overall flow of money for the battery storage operator.

Figure 4-17

Value of battery storage in a high RE scenario



4.3.2.3. Sensitivity Analysis

Three sensitivity scenarios were run to test the robustness of the main simulation findings and to examine specific market design and operational assumptions. The scenarios were designed in response to themes that emerged from the key informant interviews. These included the appropriate pace of VRE deployment, dispatch of geothermal plants, market price implications of the Ethiopian VRE expansion, and how to achieve a positive average price. The parameterisation of the scenarios is described in Section 3.4.1.6. The findings of each scenario are described below.

i. Medium VRE Scenario

Thirteen generation agents that differed between the base and high-VRE cases were set to their midpoint capacity values, adding +2,773 MW from the base scenario. The full capacity breakdown is provided in **Table 3-15**. The mean annual market price progression across the three scenarios was +67.5 EUR/MWh (base), –83.2 EUR/MWh (medium VRE), and –295.6 EUR/MWh (high-VRE). The relationship between VRE penetration and market pricing is nonlinear. The demand quartile price, diurnal, and monthly average prices are shown in **Figure 4-18**, **Figure 4-19**, and **Figure 4-20**, respectively. The demand and price duration curves are shown in **Figure 4-21**.

Figure 4-18

Demand and average diurnal price in the medium-VRE scenario

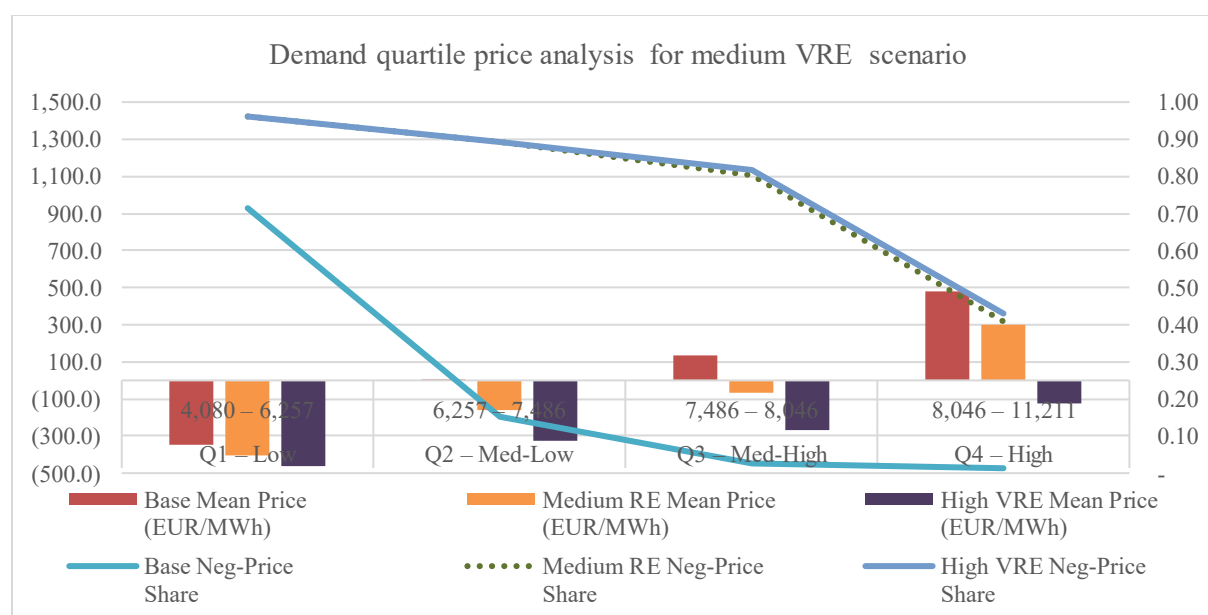


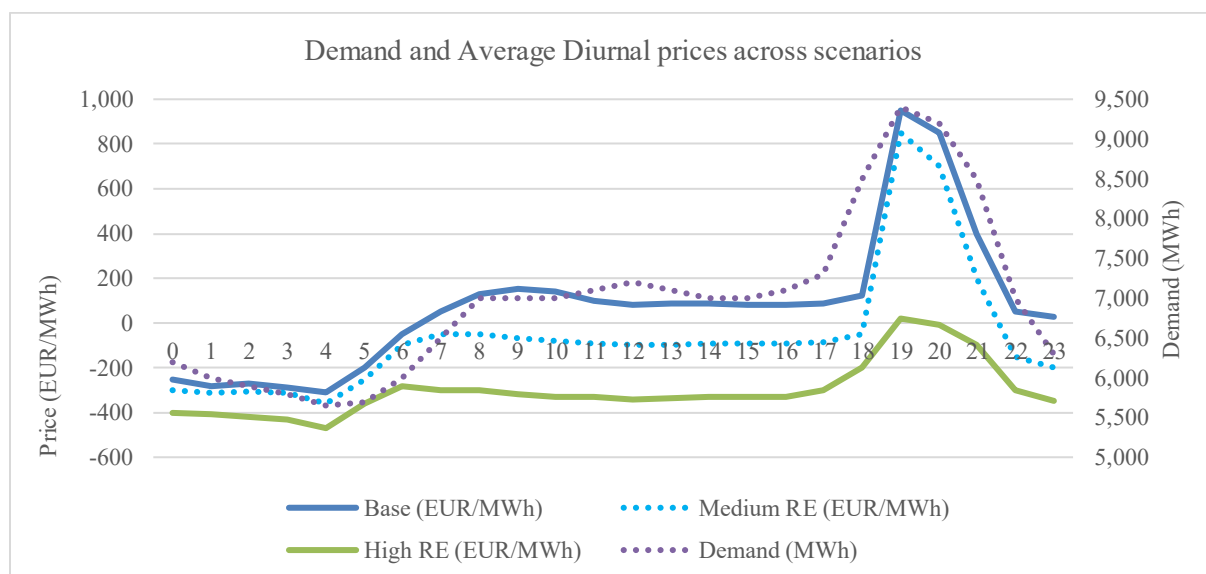
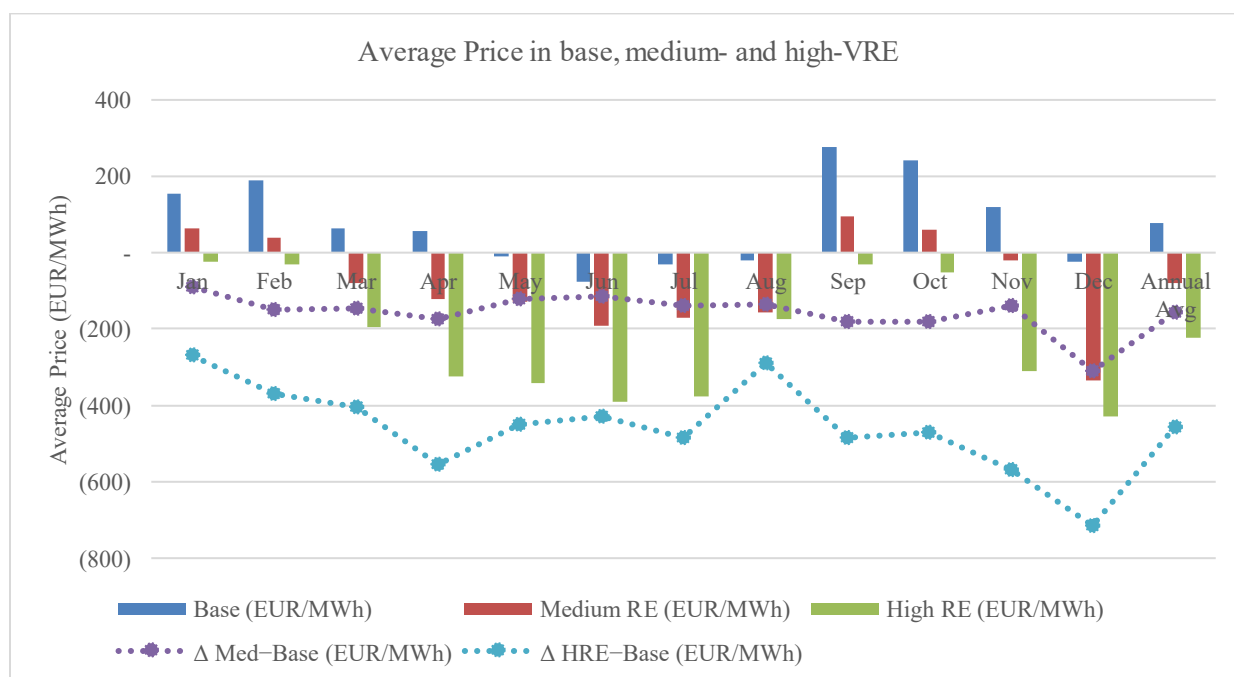
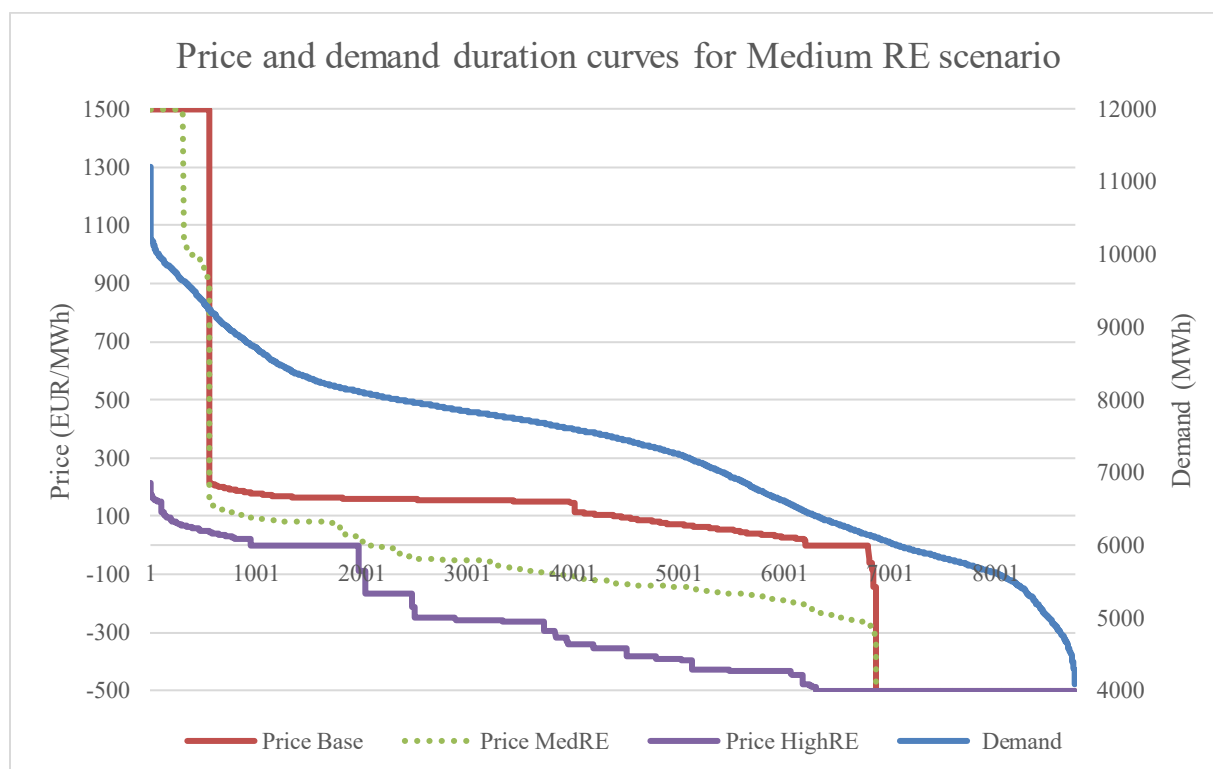
Figure 4-19*Demand and average diurnal price in the medium-VRE scenario***Figure 4-20***Average monthly price in the medium-VRE scenario*

Figure 4-21*Demand and Price Duration Curves in the medium-VRE scenario*

In the fourth quartile of demand hours, 41% of peak demand hours already return negative prices in the medium-VRE scenario, compared with only 1% in the base case. This indicates that the level of VRE penetration at which new capacity begins to erode prices is closer to the medium VRE level than to the high VRE case. The practical implication of the EAPP is that market design interventions must be introduced at an earlier stage of VRE deployment than the binary base-and-high-VRE comparison would suggest.

The evening peak price at 19:00 remains largely intact in the medium-VRE scenario at an average of +841 EUR/MWh. This peak price is +932 EUR/MWh in the base case and near-zero in the high-VRE case. This finding indicates that investment signals for dispatchable generation and storage remain commercially viable at the medium-VRE penetration level. The

medium-VRE scenario is a more realistic near-term transition state than the high-VRE case for investment planning.

ii. Geothermal Must-Run Scenario

The geothermal must-run scenario was designed to test the market pricing and dispatch consequences of assigning a must-run status to geothermal power plants. They were dispatched at full capacity, regardless of the market-clearing price. This was undertaken in a high-VRE scenario. The average price was -335 EUR/MWh and negative pricing prevailed for 7898 hrs. Geothermal was dispatched before marginal pricing mechanisms cleared the market. The demand quartile price, diurnal, and monthly average prices are shown in **Figure 4-22**, **Figure 4-23**, and **Figure 4-24**, respectively. The demand and price duration curves are shown in **Figure 4-25**.

This scenario was informed by key informants who emphasised that geothermal is a ready-to-use RE technology, already installed, at high capital costs, and should not be curtailed. Geothermal plants were curtailed in the base and high-VRE cases. Geothermal had a utilisation factor of 57.79% in the base case and 4.44% in the high-VRE case.

As geothermal energy displaces some VRE bids that would otherwise have cleared the market at a negative price, the frequency and depth of negative pricing are reduced relative to the high-VRE case. Geothermal operates at near-zero marginal cost and thus does not alter the merit order when thermal plants are dispatched. This scenario confirms that a geothermal must-run rule is feasible within the EAPP. A must-run rule for geothermal energy would not significantly distort the pricing signal for other technologies.

This finding directly informs the market design recommendations arising from the key informant interviews. However, geothermal plants in the context of the EAPP can be accommodated through vesting or contract-for-difference arrangements. These would guarantee minimum dispatch levels without exemption from the market pricing mechanism. This must-run scenario provides a quantitative basis for assessing how such an arrangement would affect overall market pricing and VRE dispatch levels.

Figure 4-22

Demand and Price Duration Curves in the medium-VRE scenario

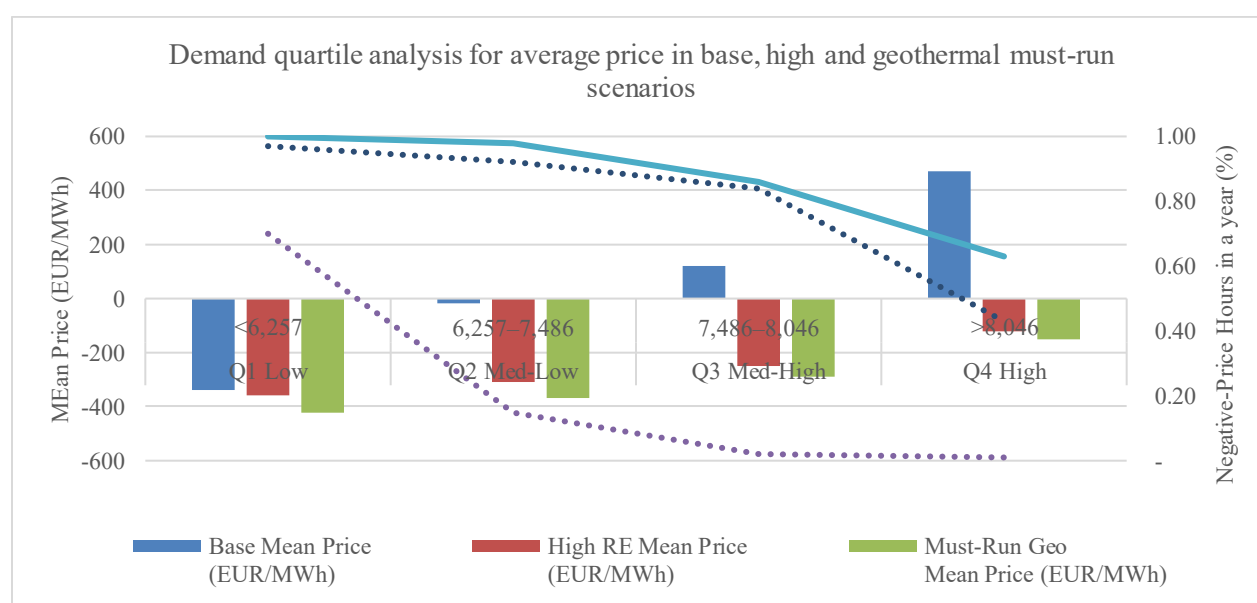
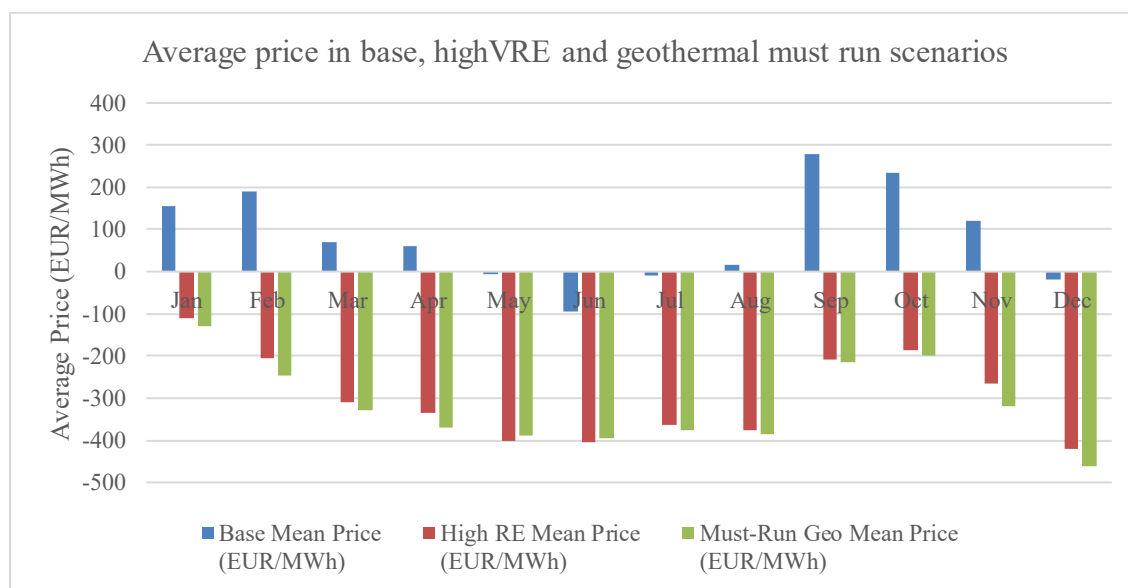


Figure 4-23

Demand and Price Duration Curves in the medium-VRE scenario

**Figure 4-24**

Demand and Price Duration Curves in the medium-VRE scenario

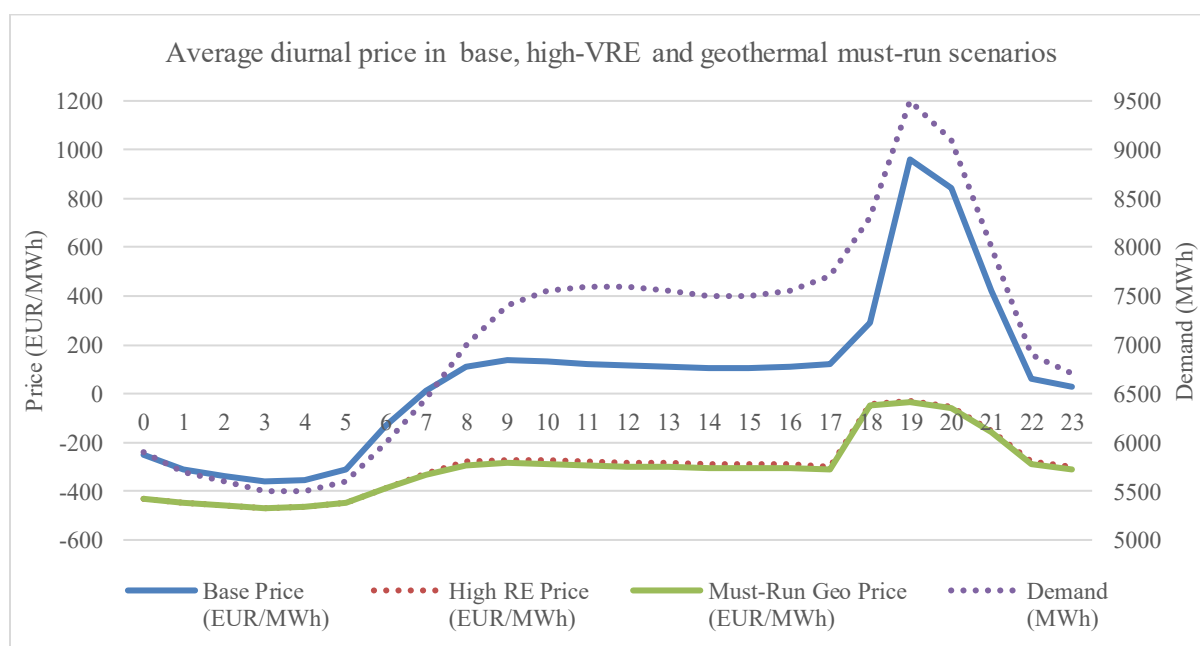
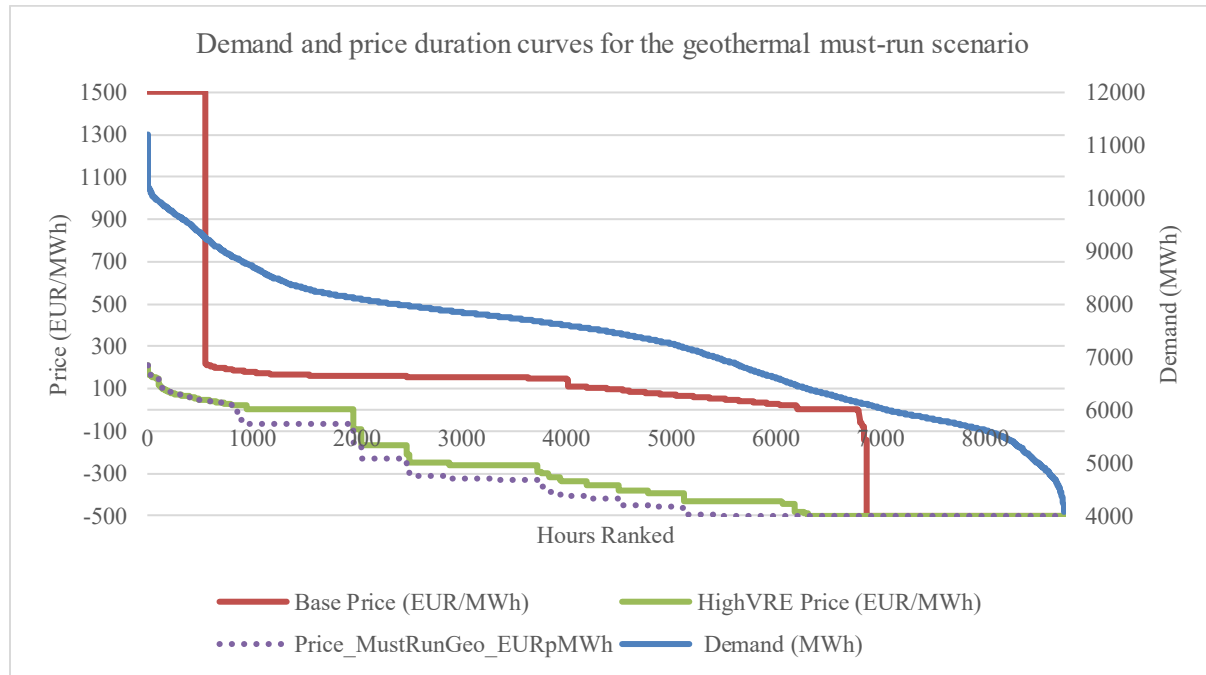


Figure 4-25*Demand and Price Duration Curves in the geothermal must-run scenario***iii. Optimal VRE Capacity Scenario**

Considering the high-VRE scenario average price of -295.6 EUR/MWh, the optimal VRE capacity scenario was designed to identify the level of additional VRE capacity at which the annual mean market price crosses zero. A scaling parameter, α , was introduced to represent the fraction of the high VRE incremental capacity added to the base case. A value of $\alpha = 0$ corresponds to the base case, and $\alpha = 1$ corresponds to the full high VRE case.

The simulation results indicate that the mean market price crosses zero at $\alpha = 0.186$. The market can therefore absorb approximately 18.6% of the additional VRE capacity planned in the high-VRE scenario before the annual average price turns negative. Beyond this threshold, the economics of oversupply erode market revenue. The demand quartile price and monthly

average prices for this scenario are shown in **Figure 4-26** and **Figure 4-27**, respectively. The demand and price duration curves are shown in **Figure 4-28**.

Figure 4-26

Demand quartile analysis for Price in the Optimal-VRE scenario

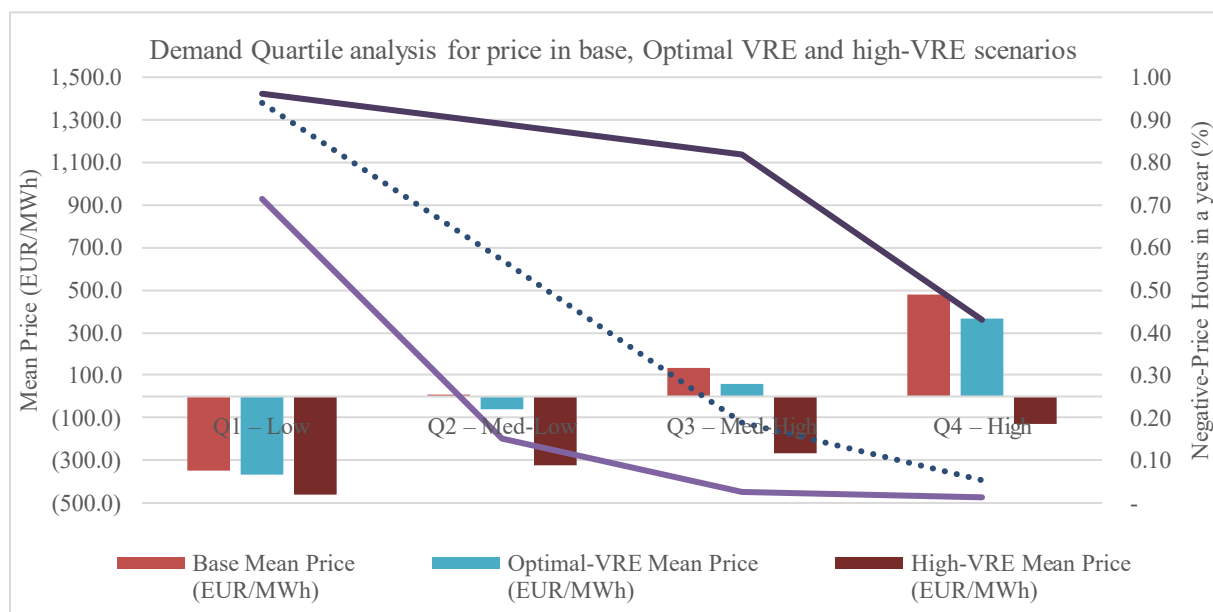


Figure 4-27

Demand and Price Duration Curves in the optimal-VRE scenario

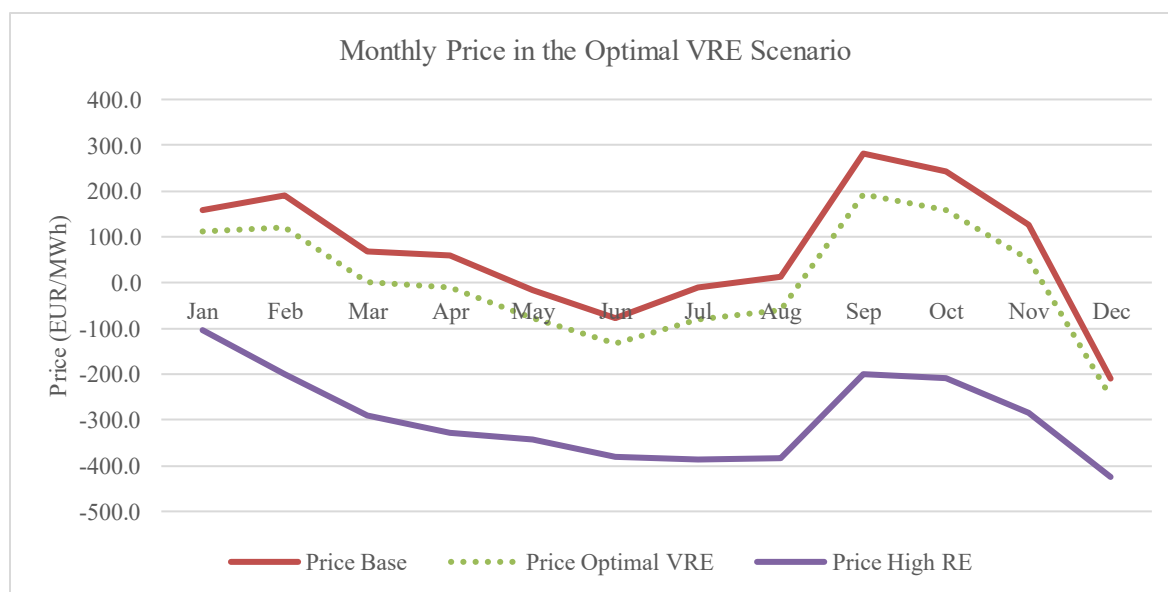
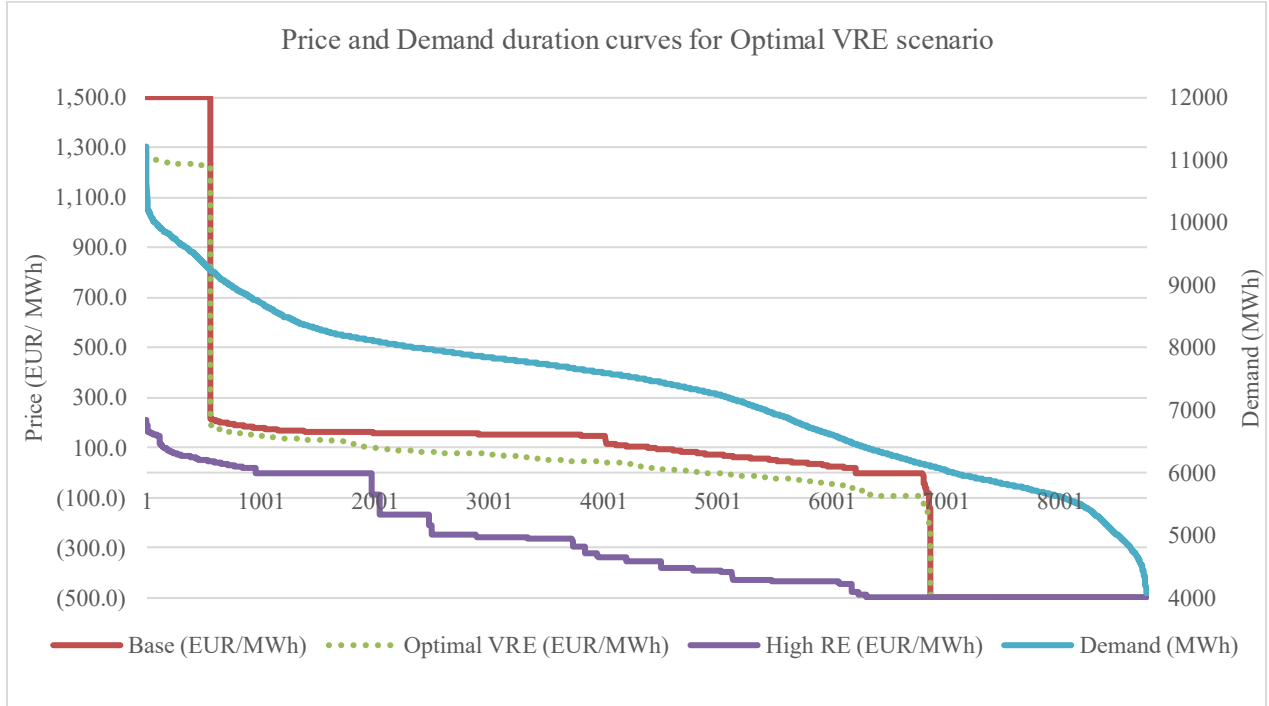


Figure 4-28

Demand and Price Duration Curves in the optimal-VRE scenario



The majority of the incremental capacity in the high-VRE case is concentrated in Ethiopian wind and solar. This scenario also derived an explicit price-capacity budget for Ethiopian generation. The price impact per megawatt of added capacity was estimated to be -0.068 EUR/MWh/MW for Ethiopian wind and -0.087 EUR/MWh/MW for Ethiopian solar. Solar output is more concentrated in the midday hours, which are already the most price-stressed. The combined constraint that holds the mean price at or above zero is

$$0.068 \times W_{add} + 0.087 \times S_{add} \leq 67.5$$

where W_{add} and S_{add} represent the megawatts of the wind and solar capacities added above the base case, respectively. These results are summarised in **Table 4-3**.

Table 4-3*Market metrics in an optimal VRE scenario*

Variable	Price impact / MW	Maximum added (price constraint only)	Optimal (combined constraint)
ET Wind	-0.068 EUR/MWh/MW	+915 MW → 1,239 MW total	+590 MW → 914 MW total
ET Solar	-0.087 EUR/MWh/MW	+721 MW → 721 MW total	+310 MW → 310 MW total

Maximising the total Ethiopian VRE capacity subject to this constraint yielded an optimal addition of +590 MW of wind and +310 MW of solar. Wind is favoured in the optimisation because its output is distributed across more hours. Solar's impact is concentrated in the already-constrained midday period. The results for this constraint are summarised in **Table 4-4**.

Table 4-4*Market metrics in an optimal VRE scenario*

Metric	Base	Optimal VRE	High VRE
Mean price (EUR/MWh)	67.5	0	-296
Median price (EUR/MWh)	102	-40	-354
Std dev (EUR/MWh)	452	420	203
Max price (EUR/MWh)	1,500	1,262	212
Min price (EUR/MWh)	-500	-500	-500
Positive-price hours	6,207	4,907	952
Positive price %	71	56	11
Negative-price hours	1,979	3,842	6,792
Negative price %	23	44	78
Floor-binding (-500) hrs	1,889	1,887	2,451
Ceiling hrs (+1500)	556	0	0
Total system capacity (MW)	19,575	20,685	26,121
Added VRE vs Base (MW)	0	1,109	5,546
ET Wind capacity (MW)	324	914	3,514
ET Solar capacity (MW)	0	310	1,675
ET Wind + Solar (MW)	324	1,224	5,189
ET Wind + Solar added (MW)	0	900	4,865

Three findings from this scenario have direct implications for generation planning in the EAPP. First, 914 MW represents the sustainable wind capacity ceiling for Ethiopia at 2025 demand levels. Second, solar and wind capacity trade off at approximately 0.79:1. For every additional megawatt of solar beyond the optimal, 0.79 MW of wind must be removed to maintain the price constraint. Third, while the maximum pricing hours disappear entirely at the optimal-VRE point, the evening peak price is maintained at an average of +761 EUR/MWh.

Consolidated Comparison Across Scenarios

Table 4-5 presents a consolidated comparison of the key metrics across all five scenarios. The variations in the metrics in the base, medium-VRE, optimal-VRE, high-VRE, and geothermal must-run variants illustrate the nonlinear price dynamics in such a market.

Table 4-5

Consolidated metrics over 5 scenarios

Metric	Scenario	Base	Optimal-VRE	Medium-VRE	High-VRE	Geo Must Run
Peak Price (EUR/MWh)		1500	1262	1500	212	212
Min Price (EUR/MWh)		-500	-500	-500	-500	-500
Mean Price		67.5	0	-83	-296	-335
Negative Price Hours		1889	3842	6712	6792	7898
Ceiling price hours		556	0	312	0	0
Total Capacity (MW)		19575	20685	19094	26121	26121

The sensitivity results collectively confirm that the pricing and dispatch outcomes in the high-VRE case are heavily driven by the scale of Ethiopian wind and solar. A more graduated approach to VRE deployment, informed by market price signals, would produce

better market outcomes. These findings are discussed further in the context of the qualitative themes in Sections 4.4 and 4.5.

4.3.3. *RQ3: How accurate are the adapted model and simulation findings for the Eastern African Power Pool?*

The accuracy of the simulation findings and assumptions was validated through the validation steps defined in Section 4.2 and through conducting key informant interviews. The interviews were conducted following the research tools defined in Section 3. This was the qualitative part of the research, and the findings were organised into themes identified in the coding process. Eight themes were identified, including electricity pricing, dispatch of power plants, stability of supply, assumptions of the model, EAPP market structure and operations, generation technology considerations, and the political economy of the EAPP. The responses from different interviewees have been organised to combine similar recurring themes and comments while allowing for differing opinions. Specific comments on the assumptions and findings of the model and simulation are enumerated below.

i. Electricity Pricing

Effect on prices: The key informants' prominent view was that power prices would decrease in a short-term wholesale market. The marginal clearing price was assumed to be, on average, lower than a bilateral PPA price over the year. These marginal prices would be driven by the marginal cost of generating using VREs. It was argued that short-term trading would help reduce the cost of electricity by allowing countries to buy cheaper power from neighbouring countries. Savings were also expected on the cost of building new plants because of the possibility of building larger-scale power plants.

Negative pricing: The informants noted that the possibility of having negative pricing in the markets will not encourage investments. Investors would not be willing to set up power plants in a market where the prices of power would be negative for significant periods. It was recommended that rules to limit how low the prices can go be defined. This would provide a minimum price that is not negative.

A contrary view was that short-term contracting would lead to higher prices, as returns for generation investors would need to be achieved in a shorter timeframe. The requirement to recover costs over shorter timeframes than the typical 20-year PPA period was viewed as resulting in higher pricing by investors.

Additionally, it was noted that VREs will have prices determined at the market. Prices were variable but largely good. VREs will piggyback on the high prices available at the market if the price is set at the margin. However, it was noted that any pricing advantages are good for consumers but may be difficult for investors accustomed to setting guaranteed PPA pricing.

Effects of congestion on price: It was believed that marginal costs would be heavily influenced by marginal congestion costs. It was necessary to design the market to avoid congestion rent pivoting. Unbundling of the electricity markets in the individual countries of the region should also be encouraged.

ii. Dispatch of Power plants

Geothermal dispatch: There was concern noted on the curtailment of geothermal energy by cheaper wind sources. It was noted that geothermal required longer operation hours to better utilise the steam resource that would otherwise be vented. Geothermal was noted as a renewable technology with high initial investment costs in steam exploration. There was a

proposal to introduce a dispatch rule to make geothermal a must-dispatch technology, regardless of market clearing price.

iii. Stability of Supply

The place of battery storage: Although battery storage did not seem to make economic sense, it is good for grid stabilisation, given high installed levels of wind and solar. It was suggested that the value of system stabilisation as an ancillary service should be factored in. Future research should endeavour to model system stability as a value or service.

Availability of in-country demand: The pool will allow for balancing the demand and supply for hourly supply. Conventional power plants will supply power when VRE cannot. The region has some countries with excess generation, which may be seasonal, that will allow them to support deficits in other countries.

However, there was a concern that the suppressed demand needed to be factored in. Demand in the countries of the region is growing rapidly and is scheduled to grow further, as a large number of citizens in the EAPP countries are not connected to the power grid. The electricity access rates for KE, UG, TZ, and ET as of 2020 were 71.4%, 42.1%, 40%, and 51.1%, respectively (Kang, 2023).

iv. Assumptions of the Model

Unrealistic assumptions: The key informants felt that the numbers for Ethiopian wind and solar in the high RE case were not realistic. The feedback was that such capacity expansion will not be achieved by 2025. There was a recommendation to undertake a staggered increase in VRE capacity. Additionally, the regulatory and political risks were not included in the model. These were proposed to lead to a more realistic model and simulation when included.

Incorporation of transmission capacity: Informants noted the need to incorporate transmission and congestion into the model and simulation. The simulation assumed an infinite transmission capacity modelling the five countries as a single zone. This assumption assumes no congestion and that electricity can flow unhindered. This assumption will obscure the constraints faced in country on generation or demand sufficiency. This leads to lower-than-expected market price. If transmission limits were to be introduced there would be countries with higher prices (where internal generation is expensive or insufficient) and those with lower prices (where internal demand is insufficient or generation costs are cheap).

Alternative simulation software suggestions: Alternative software tools that could be used in the simulation were suggested. Some of the software that were suggested included the IRENA FlexTool⁷(a capacity expansion and operation planning tool), GAMS⁸, Balmorel⁹ open-source project (this requires a subscription model GAMS and is a partial equilibrium model), and Valoragua¹⁰ (a simulation model focusing on hydropower plant modelling). However, these were not viewed as being able to improve the modelling as they were not ABM tools. They are physical infrastructure-based models and cannot handle the behaviours of agents as is required when modelling a short-term electricity market.

⁷ Models the full power system dispatch, flexible generation, demand-side flexibility, and energy storage, alongside power-to-heat, electric vehicles and hydrogen production through electrolysis. The model is available for download in the [IRENA website](#).

⁸ This is an optimisation tool that is used to find the optimal solution for complex electricity market problems. It can be applied in energy and chemical industries, for economic modelling, agricultural planning, or manufacturing. The software can be accessed from the [GAMS website](#).

⁹ is a partial equilibrium model, which supports modelling and analysis of the energy sector with emphasis on the electricity and the combined heat and power sectors. It can be accessed from the [Balmorel website](#).

¹⁰ This model is applied for the optimal management of the operation of hydro and thermal systems.

v. EAPP Market Structure and Operations

Capacity markets: It was noted that the model only considered an energy market and that a capacity market would need to be considered. Capacity market options were seen as complicated but could be organised in a competitive segment purely for capacity at various timescales.

Day-ahead market for the simulation: The choice to model the day-ahead market was appropriate and clear. Adding other short-term markets can be considered later.

Inclusion of ancillary services: The inclusion of ancillary services is essential to obtain the true value or price of VREs. Currently, the model considers only the energy price of VREs and not the system services required to support them. Stochastic and probabilistic simulations may be required to consider these. Compensation for system services that support VREs is required. It was noted that to compare the RE supply versus the conventional supply, it is necessary to determine the cost of the RE supply plus the requirements to stabilise them in the system as compared to conventional power plants.

View on short-term markets for EAPP: The informants viewed that a short-term market, beginning with a day-ahead market, is feasible and beneficial for EAPP. Some of the benefits cited for short-term markets include the promotion of competition, lower electricity prices, promotion of SDG7 (on ensuring access to affordable, reliable, sustainable, and modern energy for all), and an overall increase in efficiency.

The view was that, at Eastern Africa's stage of development, the direct participation of customers in the pool was not feasible. This was suggested to require a smart system for customers to buy directly from the pool.

Enabling factors for EAPP short-term markets: There was a proposal that power markets should be developed in-country before bringing together all countries in the pool. This would allow each country to define what is applicable to them and for different models to be tested before application to the pool. Additionally, there was a proposal to develop a proper regulatory framework based on individual country markets.

It was noted that capacity building was needed to overcome inertia and promote a transition away from bilateral trade. Training to build the capacity of policymakers and develop the understanding of market players was required. It was foreseen that legacy bilateral and long-term PPAs would control the market for some time unless measures were put in place to limit this control.

The establishment of an independent system operator who is independent and capable of providing transmission capacity to all participants. This party would also be responsible for providing signals and information to market participants. To this end, a regional regulator should be established that can oversee market manipulation, especially collusion among bidders.

Additionally, political stability and cohesion were required of a central market operator and a regional coordination centre. Working to insulate the pool from the politics of the region and ensuring the professional operation of the pool were also necessary. There would also be a need to shield the market from nationalistic thinking in the countries of the pool.

The countries in the pool would need to maintain a high level of reliability for all grid systems in generation, transmission, and distribution. Conformity to an Africa-wide standard

that anticipates the AfSEM¹¹ being developed under the AU as well as SAPP integration was necessary.

Major hindrances for EAPP short-term. The lack of uniform regulations in EAPP member countries was seen as a major obstacle to the implementation of a short-term market. The creation of uniform regulations is necessary. The informants deemed it necessary to initiate a process to standardise regulations. Another hindrance was the insufficient coordination of developments in the electricity markets of EAPP countries. Regulations were seen as a possible solution to this issue.

The involvement of policymakers in the activities of the power pool, often spearheaded by technical working groups, was deemed necessary. Policymakers in the region were seen to be unaware of the power pool and short-term markets and were used to bilateral arrangements based on PPAs. Capacity building and political buy-in are needed.

The amount and transfer capacities of regionally interconnecting transmission lines were seen as a hindrance to short-term trade. Trade was seen to be encouraged by the availability of more transmission capacity and at diverse nodes of the grid.

The existing bilateral agreements were viewed to hinder the adoption of short-term trade. This was seen to be a consequence of aversion to change and countries wanting to secure security of supply ahead of other market participants.

Key informants perceived a lack of robust systems in banks to ensure effective trade. The SAPP was reported to pay 14 days after market clearing, while the European market was reported to pay instantly after gate closure. European banks are connected to the market

¹¹ The Africa Single Electricity Market, launched by the African Union in 2021. More details [here](#).

operator's system. There is a need to harmonise the operations of the banking system and the market.

Availability of a regional short-term market and development of more variable renewable energy sources: Yes, the short-term market will lead to more variable renewable energy sources as the current planning is based on restricted load per country. The power market will allow power plants to be built using a merchant approach. The business model will depend on the market's ability to offtake. The development of new wind and solar power will depend on the rising demand to justify increased supply. Knowledge of the availability of the market for offtake will incentivise all technologies and smaller investors.

It was noted that there is a need to harmonise and distribute the amount that each country can undertake in RE to enable the coordination of resource development. A regional generation expansion plan was considered necessary. It was suggested that the amounts of renewables that each market can develop be apportioned. Each country could be allowed to develop VRE systems based on their demand, as a proportion to the total. This will also help to forestall the risks of loss of national interest and energy security of a nation.

It was also noted that VRE plants would need some form of dispatch guarantees to a certain level for the pool to work for them. Conventional plants that are required would need a capacity market, as they cannot rely on energy-only.

vi. Generation Technology Considerations

Consideration of technical minimums for technologies: There was a suggestion that the modelling should enforce technical minimum operational levels for the given technologies in the simulation. These technologies should then be allowed in the model to run at a required

minimum level. Specifically for hydro, there was a request to find a way to include low hydrology periods in the average data.

It was believed that battery storage would require an overinvestment in the generation facility to ensure the capacity to meet PPA requirements, as well as the energy required to charge the batteries.

Standardisation of the highest voltage of transmission for cross-border HVDC at long distances and HVAC for shorter distances. The need for a uniform voltage level of transmission has been noted.

vii. The political economy of EAPP

The overall views of the informants on the pool were positive. The EAPP was seen as allowing the sharing of generation resources, which consequently allows for overall economies of scale for power plants built in the region. It was suggested that countries could choose focus technologies. For instance, KE can focus on geothermal, TZ on LNG, and ET on hydropower. This will allow larger plants to be built. Scale brings about lower costs.

The pool provides a platform for countries to benefit from least-cost energy from their neighbours, which leads to higher economic welfare in the region. This was indicated to lead to a higher economic welfare for the region. The EAPP is also seen as being more pro-consumer than traditional PPA approaches, which are seen to favour investors and utilities more.

The pool was seen as allowing the expansion of market liquidity. Constrained liquidity in the region has been identified as an issue. Many different participants will cause the market to expand and lead to more economic development.

There were some concerns raised about EAPP. It was noted that countries were focusing heavily on their own markets and ensuring their own supply instead of building the pool. There

had been drawbacks in bringing countries together due to national interests. It was recommended to start the market and deal with teething problems.

There was a recommendation that the region should find a way to insulate the EAPP from the geopolitics of the region. At the EAPP council of ministers, decisions made at the technical level were reported to often be watered down. The geopolitics of the region was recommended to be delinked from the pool. There was a recommendation to find out how the SAPP has managed to delink the pool operations from the regional geopolitics. The interviewees were of the view that the EAPP can also learn a lot from the operations of the SAPP.

CHAPTER 4.4: EVALUATION OF FINDINGS

This section evaluates the research results in relation to the theory, simulation, and key informant interviews. The evaluation is undertaken following the research questions. A description of the conformity of the results to the expectations of the research is provided, and potential explanations are offered for unexpected and conflicting results.

4.4.1. RQ1: How is electricity traded globally and in Eastern Africa?

The research responses from the key informant interviews showed similarities with the findings of the literature review in terms of how electricity is traded in Eastern African countries (Rudnick & Velasquez, 2018). The five countries that focus on KE, RW, TZ, UG, and ET have similar market structures, with variations in the levels of unbundling. UG has the most unbundled electricity sector, while RW, TZ, and ET have more centralised structures, as described in **Figure 4-29**.

Figure 4-29

Comparison of the unbundling levels of the five EAPP countries. Green indicates full unbundling.

	Generation	Transmission	Distribution	Retail	Offgrid
Kenya	Green	Green	Red	Red	Green
Uganda	Green	Green	Green	Green	Green
Tanzania	Red	Red	Red	Red	Green
Ethiopia	Green	Green	Red	Red	Green
Rwanda	Green	Green	Red	Red	Green

All countries except Ethiopia (where a procurement process is ongoing) have IPPs operating power plants in the electricity market in conjunction with the state generator. Uganda

has introduced competition in the distribution and retail sectors with concessionaires awarded supply areas. Overall, the region's market operates based on PPAs signed between generators and utilities for new power plants with tariffs agreed bilaterally or through feed-in tariffs. These PPAs are typically signed for contractual periods of 20 years, with the possibility of extension. Electricity trade is undertaken via these long-term contracts, with no short-term trade. However, KE is planning to introduce short-term trading linked to the EAPP and electricity wheeling by private parties, similar to EPRA (2024). The five countries all have renewable energy power plants operational on their grids. These are dominated by wind, solar, hydropower, and geothermal sources.

In terms of regional trade, countries have interconnections that allow power to move across national boundaries. However, these do not exist between all countries, and in some instances, they have a low capacity of transfer. The transfer capacities are illustrated in **Table 3-2**.

Power trading is conducted by bilateral PPAs between utilities, such as ET and KE, and by power exchanges, such as KE and UG. There is no short-term trading or market operation.

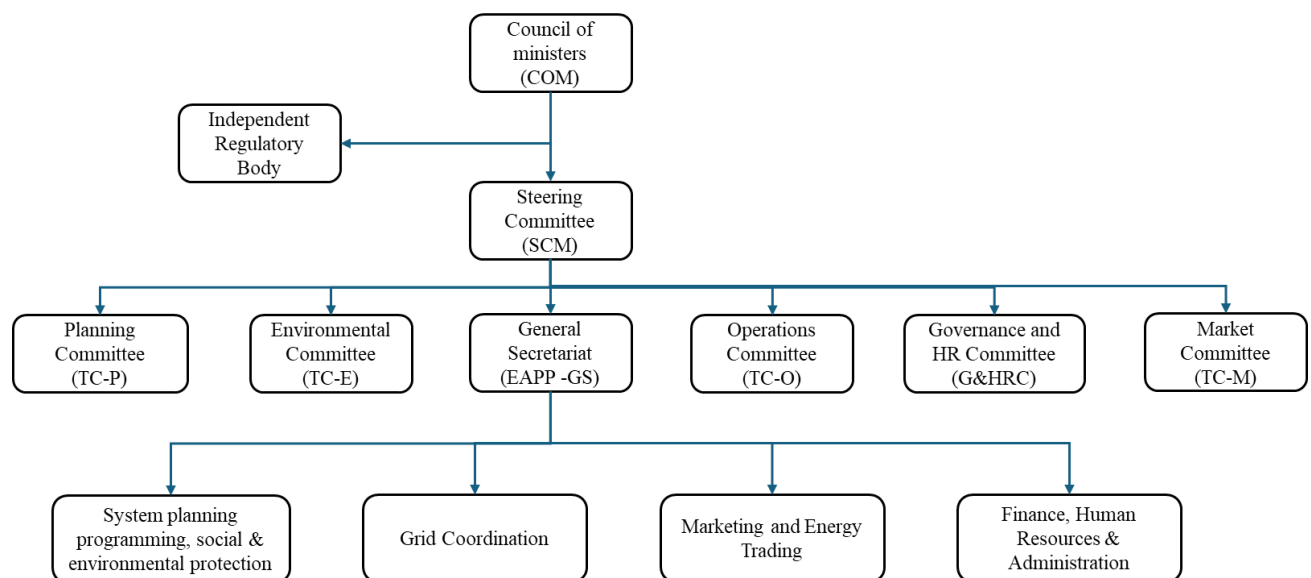
However, from the key informant interviews, it is clear that the region is moving toward the development of a regional market for electricity, with the EAPP advancing toward agreed norms for launching a market. The EAPP, with its secretariat in Addis Ababa, Ethiopia, is the organisation that brings together all the countries of the EAPP into a pool. The pool intends to start a power market based on a day-ahead market in 2025. This finding aligns with the literature on the EAPP (Elabbas, 2023b, 2024). Currently, the region has established a regulator based in UG, is developing market operation guidelines and rules. There also exists a regional regulatory union between the different regulators, and the pool convenes a ministerial committee that deliberates and decides on policy interventions to push the pool forward. The

basic structures of a regional day-ahead market are being set in place, with an expectation that the market will launch in 2026.

The reviewed literature indicates that the EAPP operates from an office and planning perspective (Elabbas, 2023b). Key informant interviews showed progress in narrowing down the day-ahead market, developing a regional code of operation, establishing an independent regional regulator, progressing toward the acquisition of market operation software, and identifying a regional system operator. The current structure of the EAPP market is shown in **Figure 4-30**.

Figure 4-30

Structure of the EAPP market



Note. Sourced from Nord Pool Ricardo (2021).

These advancements in the EAPP imply that the market is moving toward being ready for the introduction of short-term trading initially via a day-ahead market. Legacy bilateral arrangements would, however, also continue along the short-term market.

Globally, markets have been more advanced, introducing short-term markets over 30 years ago. Regionally, the EAPP lags developments in the SAPP, which has already started short-term trading with a day-ahead market and has further progressed in the launch of a short-term market.

The SAPP is structurally different from the EAPP, with the inclusion of an executive committee and a management committee and a coordination centre with a board. The SAPP structure is illustrated in **Figure 4-31**. The SAPP has delegated authority from the Southern African Development Community (SADC), allowing the structures of the SAPP to make decisions on non-policy matters directly (Marumo, 2020). This is in contrast to the EAPP, which has ministerial coordination meetings to make decisions, as confirmed by the key informants.

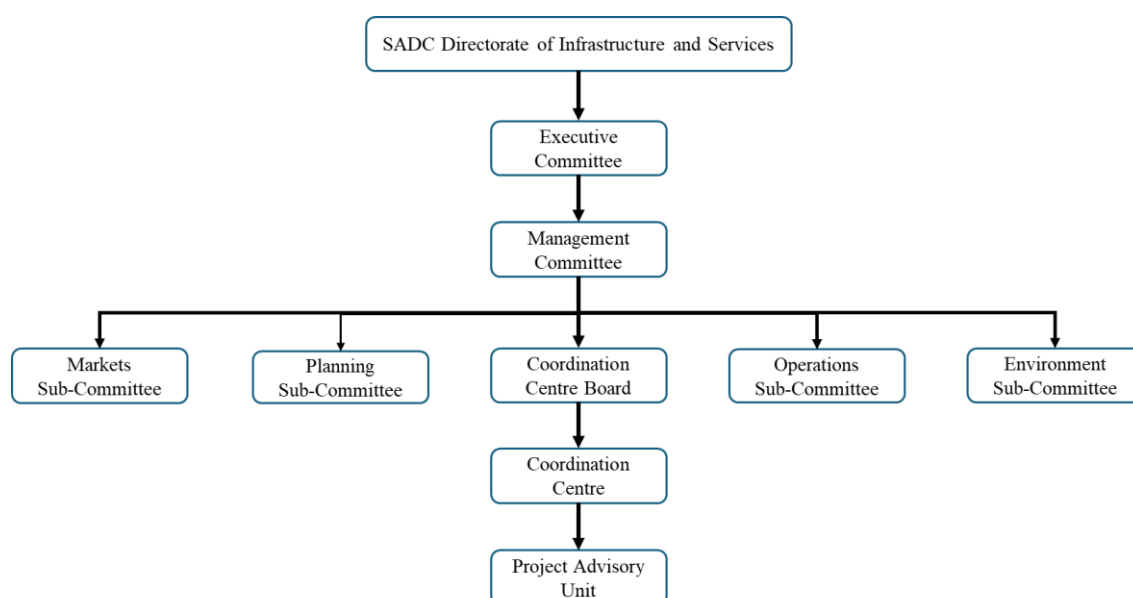
The Executive Committee of the SAPP comprised the CEOs of the operating members of the SAPP utilities. The committee makes decisions regarding the operations of the management committee, as well as all subcommittees and the coordination centre. The management committee oversees the work of the subcommittees and the coordination centre board, including the determination of fees, ensuring data collection, and facilitating the coordination centre among other roles. The coordination centre is responsible for the day-to-day operation of the pool and for coordinating the trade in electricity among members of the SAPP.

The SAPP's robust structure and clear mandate have enabled the launch and operation of short-term markets, with day-ahead and balancing markets. However, the SAPP faces challenges related to market depth, as the volumes being traded are minimal compared to pre-agreed bilateral arrangements. The infrastructure of the SAPP is also aging, with a need to invest in the construction of new transmission lines and the renovation of old power plants

(Moeko & Visser, 2013; Ndlela et al., 2023). The SAPP also faces inadequacies in power generation capacity and load management. In contrast, the EAPP currently has multiple countries (i.e., Tanzania, Uganda, and Ethiopia) with surplus generation that would require evacuation opportunities.

Figure 4-31

Structure of the SAPP market



Note. Sourced from the SAPP website (SAPP, 2025).

The transition to wholesale markets includes provisions to allow the acquisition of capacity through bilateral markets. This is aimed at avoiding the ‘missing money’ problem, in which generators struggle to recover their fixed costs solely through energy-only revenues. These capacity acquisitions are medium- to long-term in nature, guaranteeing supply and system reliability (D. R. Biggar & Hesamzadeh, 2025). This capacity is acquired through parallel capacity markets, the need for which is debated in both the literature and practice. Proponents of energy-only markets argue that sufficient compensation (without price caps) for

times of over- or under-supply will sufficiently compensate generators to cover the ‘missing money’ (M. Hogan, 2017; W. W. Hogan, 2015).

In developing countries, legacy bilateral contracts, the terms of which are still in effect at the introduction of wholesale markets, are allowed to run (Rudnick & Velasquez, 2018). In 2021, 80% of developing countries had not established wholesale markets and continued to operate on bilateral markets (Chattopadhyay & Klein, 2021). The arrangements in existing markets normally continue to dominate trade in a pool as the short-term market is introduced. The short-term portion of the market then grows as more demand and supply become available, and legacy bilateral contracts reach the end of their terms. The transition in the EAPP is expected to follow the same progression as existing bilateral arrangements, such as ET-KE and UG-KE and ET-TZ, continuing to dominate trade in the pool as the short-term market progressively adds market participants and volumes.

4.4.2. RQ2: How would the introduction of more variable renewable energy affect wholesale electricity markets in Eastern Africa?

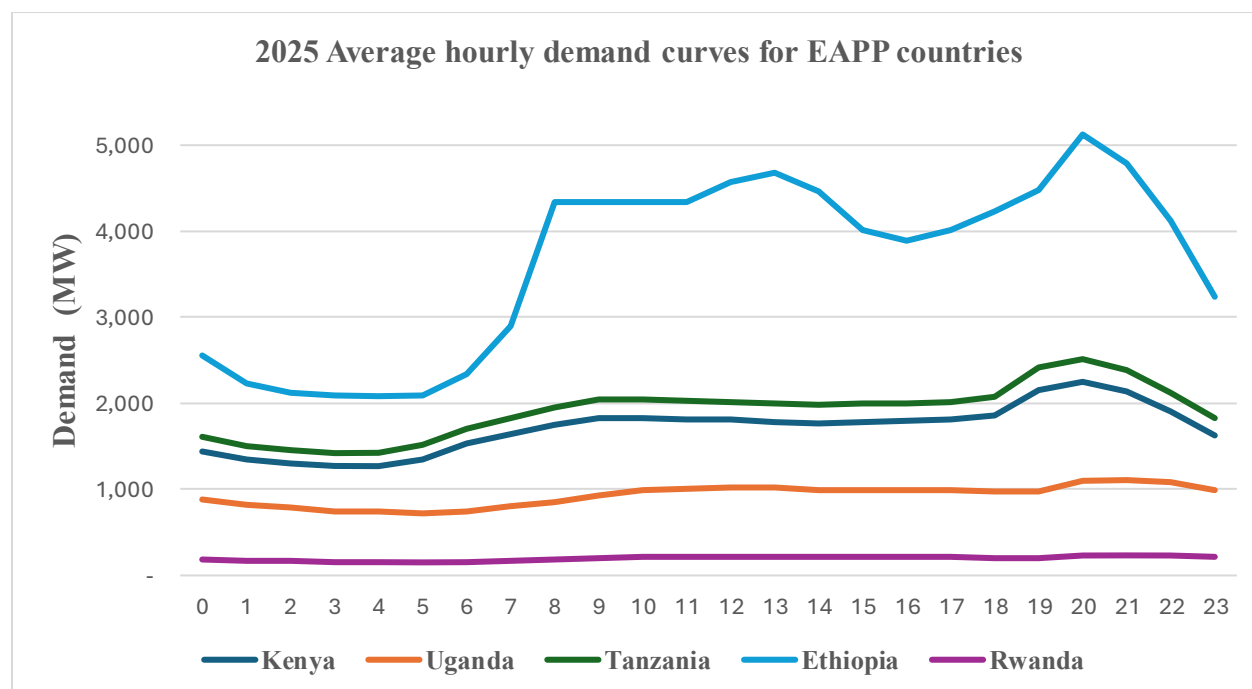
As there does not exist a wholesale electricity market in Eastern Africa, the market was modelled using a software simulation, as described in Chapter 3. This model was then subjected to two scenarios, including a normal case and a high renewable energy penetration case. The effects of increased renewable energy penetration on various aspects, including electricity prices, awarded energy to various renewables, awarded energy to conventional plants, effects on market support instruments, effects on fuel consumption and CO₂ emissions of power plants, and the proposed economics of battery storage plants were analysed.

4.4.2.1. Electricity Prices

The simulation showed that if the EAPP markets were perfectly interconnected in 2025 with the generation and demand that will pertain, the average electricity price would be 67.5 EUR/MWh. However, there would be an insufficient supply during evening peaks, which would lead to the marginal price hitting the ceiling price of 1500 EUR/MWh for 556 hours per year. This achievement of maximum prices implies that there would be insufficient supply to cover the regional demand during peak periods in the base case. The load curves of the five eastern African countries are similar, experiencing a night peak between 6 and 10pm. **Figure 4-32** depicts the peaks of the five eastern African countries. At peak times, solar power is unavailable, and the seasons of low wind resources exacerbate the problem. This explains the periods when the ceiling price is hit by the market because of the scarcity of supply.

Figure 4-32

Modelled load curves for EAPP countries in 2025



Note: Developed in the modelling process

In the high-renewable scenario, the instances of load shedding end as the price of electricity in the market drops significantly to an annual average of – 295 EUR/MWh, as summarised in **Table 4-6**.

The base case finding of 556 ceiling-price hours represents the hours in which demand cannot be fully served. This is both a supply-security indicator and an investment signal. In this scarcity period, new peaking capacity would earn the revenue needed to justify its investment. The disappearance of these hours in the high-VRE case is, therefore, not positive from an investment perspective. It eliminates the scarcity revenue on which peaking plant economics depend, and is one of the drivers of the battery storage commercial loss documented in the research findings

Table 4-6

Statistics on Electricity pricing in the Base and High RE cases

Price (EUR/MWH)		Base Case		High VRE Case	
		Statistic	Std. Err.	Statistic	Std. Err.
Mean		67.50	4.83	-295.57	2.17
95% Confidence Interval for Mean	Lower Bound	58.04		-299.82	
	Upper Bound	76.96		-291.33	
5% Trimmed Mean		19.45		-306.05	
Median		101.67		-353.87	
Variance		204046.74		41066.20	
Std. Deviation		451.72		202.65	
Minimum		-500.00		-500.00	
Maximum		1500.00		211.90	
Range		2000.00		711.90	
Interquartile Range		158.53		334.17	
Skewness		1.60	0.03	0.67	0.03
Kurtosis		3.96	0.05	-0.96	0.05

A Sample of the first 2000 hrs of the simulation for the electricity price in **Figure 4-33** and **Figure 4-37** shows that the maximum price achieved in the high RE scenario is approximately 100 EUR/MWh. Further statistics on pricing are presented in **Figure 4-34**, **Figure 4-35** and **Figure 4-36**.

The additional RE capacity improves the availability of generation to meet peak demand and eliminates instances of ceiling prices. If the constraints on the network are included, the prices for electricity would likely increase, and any congestion in transmission lines implies more significant peak-time load shedding.

Figure 4-33

Sample of the electricity price for the first 2000 hrs of the year in the base case

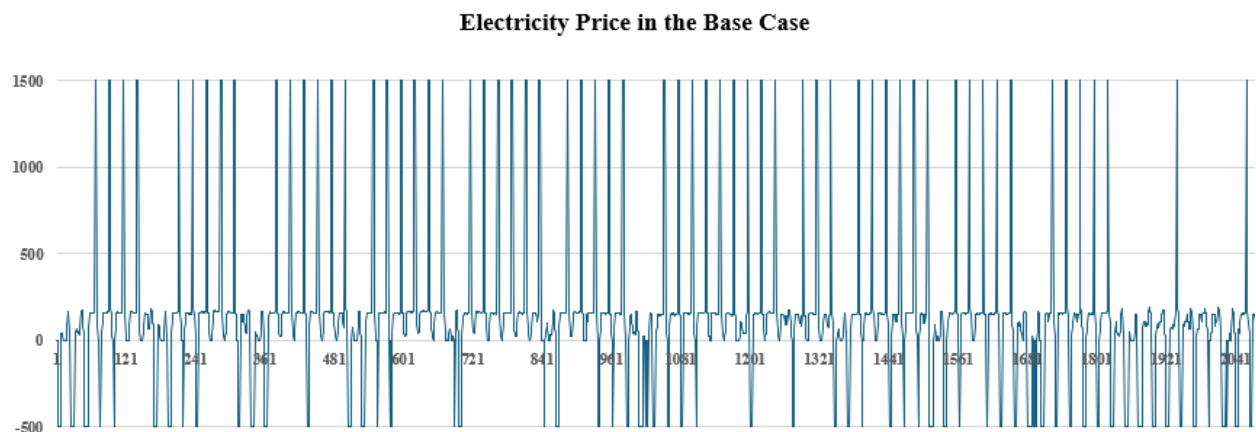


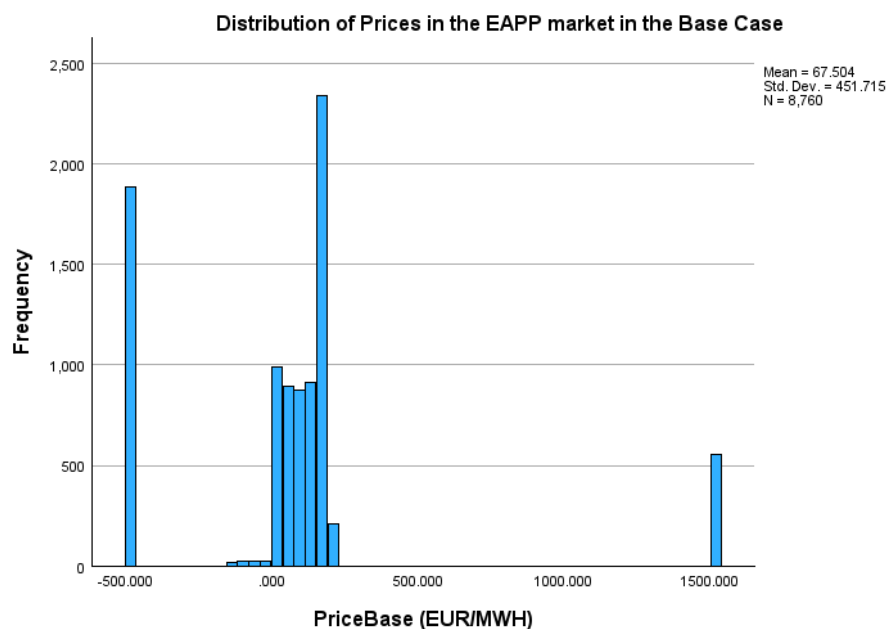
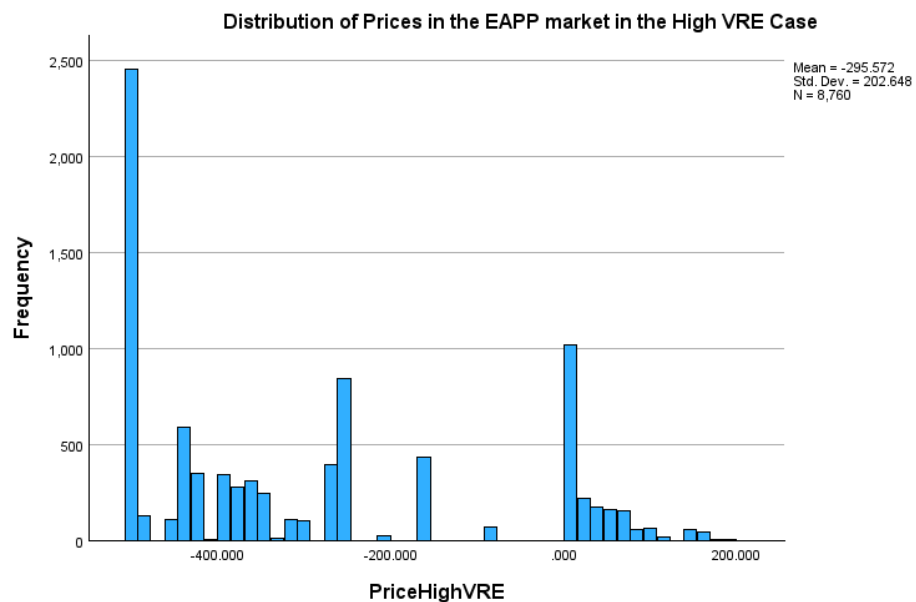
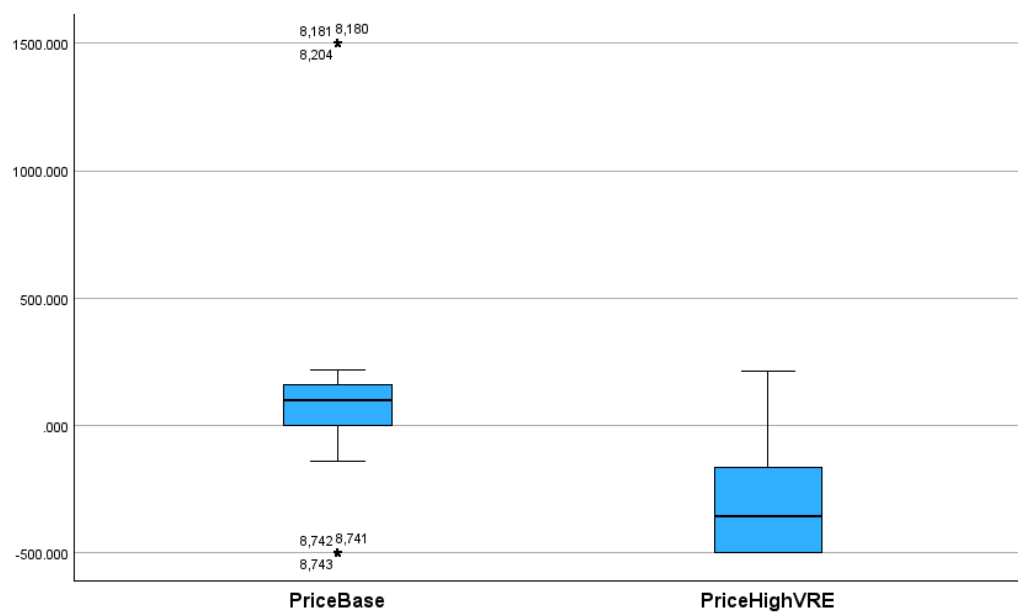
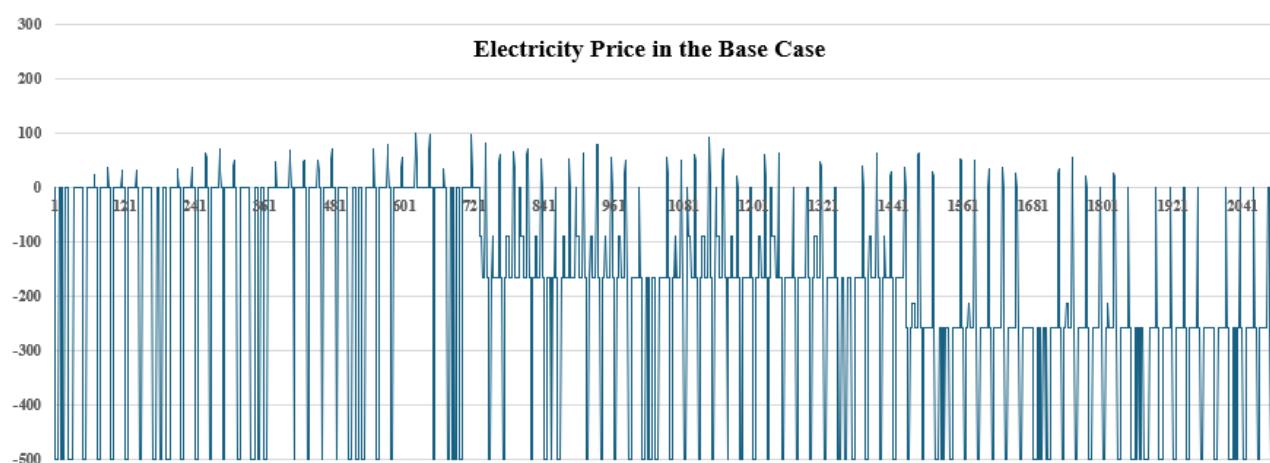
Figure 4-34*Hourly Price distribution in the EAPP base case***Figure 4-35***Hourly Price distribution in the EAPP High VRE case*

Figure 4-36

Stem and leaf Hourly Price distribution in the EAPP Base and High VRE case

**Figure 4-37**

Sample of the first 2000 hours of the year in the high RE scenario



However, the high-VRE scenario introduces significant instances of negative pricing because of the abundance of wind and solar power installed on the grid. The high-RE scenario

assumes a five-fold increase in wind capacity and a corresponding seven-fold increase in solar capacity based on the generation expansion plans of the countries. Prices in the EAPP market were negative for 77% of the hours in a year, up from 22.6% in the base VRE case. This compares to between 4% and 25% of the hours in a year, as observed in the U.S. markets (Seel et al., 2021).

If these low prices materialise, they would likely result in underinvestment in new-generation facilities, unless regulatory or financial interventions are taken to ensure that investors recover their investments or achieve an acceptable rate of return. This finding is consistent with research on wholesale markets with high VRE levels (Atănăsoae et al., 2020; Seel et al., 2021; Sewalt & De Jong, 2003). The relationship with the inflexibility of demand is, however, also given prominence in literature (Halbrügge et al., 2024).

The qualitative process, however, added different perspectives on the effects on pricing. While the key informants generally agree that a wholesale market would lead to lower pricing, as noted in the literature, there was a contrary view. There was a view that, because the contracts in a wholesale market would be shorter, there would be an attempt to recover costs quickly and thus higher pricing. A related view was that VREs would piggyback on obtaining high prices because of setting prices at the margin. However, this view is not supported by literature or in the simulation, as marginal prices tend to be led by abundant VREs at low marginal prices (Pavlík, 2025; Rafizadeh, 2026). Technical, market-based, and regulatory solutions have been proposed to overcome this challenge, which is caused by the overproduction of wind and solar when demand is low (Pavlík, 2025; Q. Sun et al., 2026). These instances of negative pricing would also be a disincentive for new investments, as observed by the key informants.

Grid conditions have also been found to lead to negative prices (Pineau & Rafizadeh, 2023). This is in line with the opinion of the key informants that negative pricing could result from the over-estimation of available wind and solar generation in Ethiopia. They argue that the expansion plan for Ethiopia exaggerates the level of wind and solar on the grid and, thus, significantly increases the available generated electricity, thus causing negative prices. This is a major factor in the higher instances of negative pricing. Additionally, the key informants state that the lack of consideration of grid constraints and related congestion costs when transferring energy across countries leads to high instances of negative prices. Prices will be higher when there are limitations and an associated cost to the amount of power that can be transferred across countries.

4.4.2.1.1. Addressing the Negative Electricity Prices

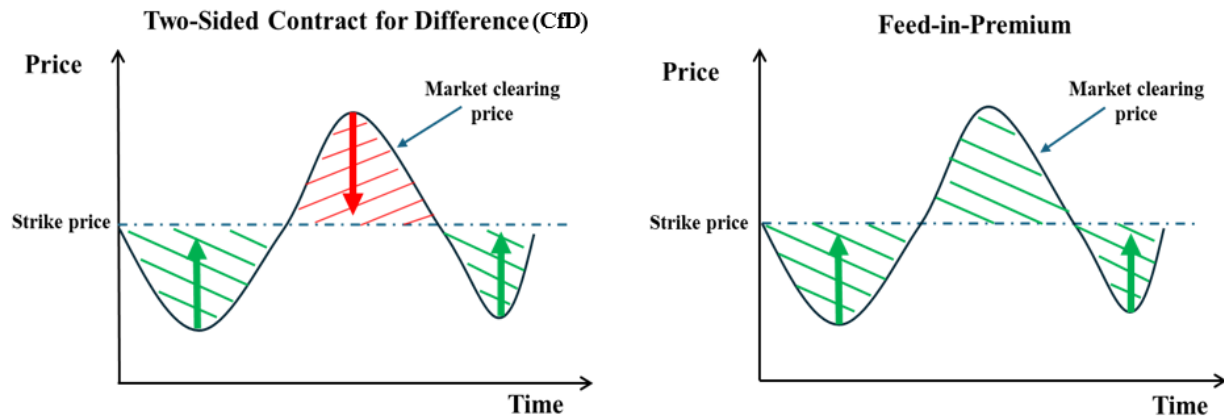
Negative electricity prices disincentivise investors looking to establish renewable power plants (Ríos-Ocampo et al., 2021). This is the same observation from the key informant interviews and is the ‘missing money’ problem (Stoft, 2015). Regulatory intervention is required to ensure that renewable investors are sufficiently compensated for their investments (Q. Sun et al., 2026). Other researchers however argue for an energy only market that allows for full swings in pricing in both the negative and positive directions without caps (M. Hogan, 2017). This balance between regular marginal pricing and high and negative prices is argued to leave the operator whole. Conversely negative prices will be charged at times of extremely low demand. This balance between regular marginal pricing and the high and negative prices is argued to leave the operator whole. However, has been applied in a few markets including Texas (ERCOT), U.S.

Regulatory intervention to curb negative pricing and solve for the ‘missing money’ can be achieved by utilising contracts for difference and feed-in-premiums, as depicted in **Figure 4-38**. These schemes are applied to reduce the financial risk in wholesale markets for investors in VRE power plants. A minimum price or strike price is agreed upon with the developers of the VRE power plant, and then, CfDs are applied. The strike price can be linked to the LCOE of the specific technology plus an allowable rate of return for the investment. LCOE numbers as regularly tabulated by IRENA such as in IRENA (2023) can be applied. However, these need to be adjusted to the EAPP average financing costs.

CfDs provide price support for VRE sources and encourage investments in such technologies (Ason & Dal Poz, 2024). CfDs allow market operators to guarantee a price level for generation from new plants. In a two-way CfD, when the market price is higher than the agreed strike price, the market recovers the difference, and the specific powerplant is only paid the strike price. Conversely, when the market-clearing price is lower than the strike price, the market provides funding for the difference required to achieve the strike price, and the generator pays the strike price.

Figure 4-38

Schematic of CfD and feed-in-premium showing gains and losses by the generating company relative to the strike price



In contrast, feed-in-premiums compensate the power plant by providing the funds required to raise the market price to the strike price in case of deficits. Feed-in premiums do not internalise the benefit when market prices are higher than the strike price. In this scheme, the generator is allowed to retain the profits from market clearing prices higher than the strike price.

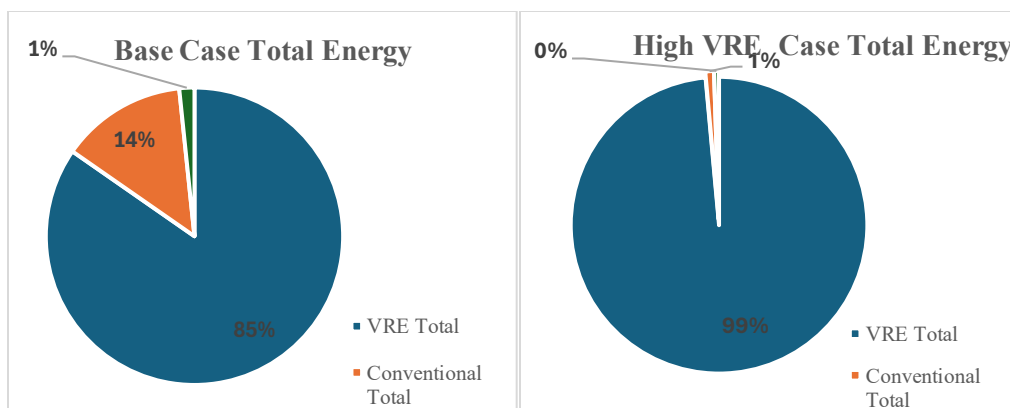
Negative prices could also signal overinvestment in RE capacity (Q. Sun et al., 2026) and suggest that a staggered approach to installing VRE sources is required. This staggered buildup could be achieved by optimising incremental capacity, technology, peak demand, and cost. This represents a prevalent view in the literature, suggesting that negative prices should be tolerated as a signal of resource allocation inefficiencies in the market. This then triggers corrective or pre-emptive actions, such as generation investments, transmission and storage development, and opportunities for demand growth (Halbrügge et al., 2024; Jia et al., 2025).

4.4.2.2. Dispatch and Energy Awarded to Power Plants

Power plants in the model were awarded different levels of opportunities supply. This was based on the marginal cost of generation for each power plant. In this section, the dispatch of various renewable, conventional, and bioenergy power plants is described. The power plants were grouped into technology-specific bundles for each country and modelled as a single plant of a specific technology and codified, as depicted in Appendix VI. In both the base and high-RE cases, VRE dominated the supply of energy, with 85% and 99% of the energy supplied, respectively. Conventional power plants contributed 14% and 1%, respectively. This is consistent with the literature on wholesale mar(Pavlík, 2025; Pineau & Rafizadeh, 2023; Rafizadeh, 2026; Seel et al., 2021; Q. Sun et al., 2026)al., 2021; Q. Sun et al., 2026). **Figure 4-39** shows the energy mix from different sources in the base and high-VRE cases.

Figure 4-39

Percentage of energy supplied by technology in base and high RE case

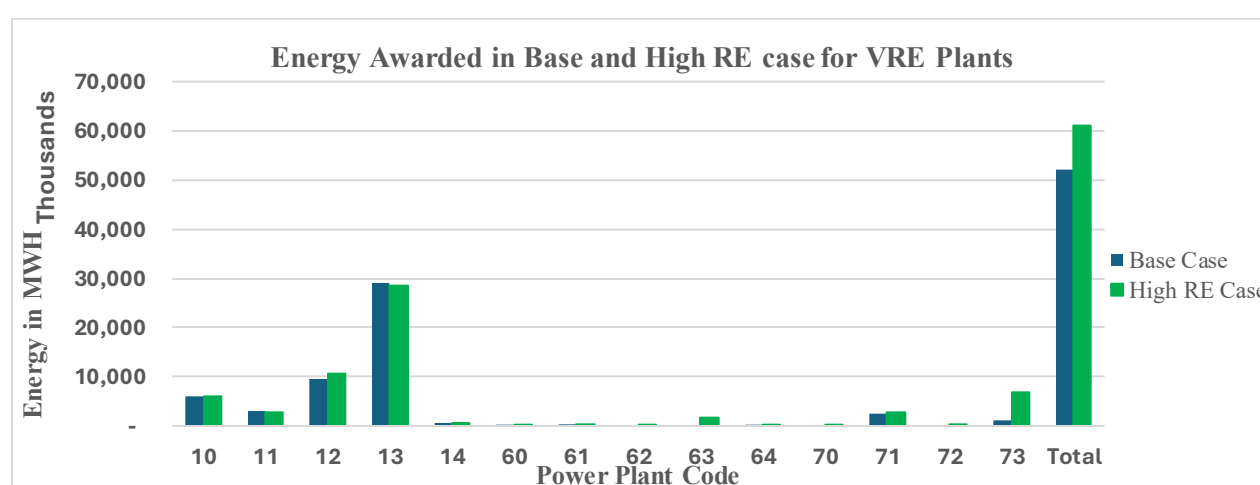


4.4.2.2.1. Varying Renewable Power plants

For this research, the technologies that were included as VRE power plants were wind, solar, and hydro power. Hydro power plants with dams were modelled as run-of-the-river power plants, allowing them to be modelled as varying renewable energy plants¹². The energy awarded to VREs in the base and high-VRE case is as shown in **Figure 4-40**.

Figure 4-40

Energy awarded to varying renewable Power plants



The varying renewable energy plants dominated the awarded energy in the EAPP for both the base and high-RE cases. This was driven by hydropower, which contributed 47.377 TWh of the 61.499 TWh in the base case and 47.977 TWh of the 62.126 TWh in the high-RE case. Ethiopian hydropower installations dominated the energy dispatched into the EAPP system. Overall, these varying renewable power plants had a utilisation factor (dispatched energy as a fraction of the theoretical maximum energy) of 36.11% and 32.1% in the base and

¹² This assumption was necessary to simplify the modelling process and computing requirements.

high-RE cases, respectively. Hydropower plants had utilisation factors of 37.97% and 38.46%, as summarised in **Table 4-7**.

The utilisation factors (UF) for wind and solar are related to their capacity factors in the base case because of their low marginal costs and eventual higher levels of dispatch. The UF reduces in the high-VRE case because of curtailment related to low levels of demand.

Table 4-7

Utilisation Factor per technology in the EAPP Base and High RE cases

Technology	Installed Capacity (MW) Base Case	Installed Capacity (MW) High RE Case	Utilisation Factor Base Case	Utilisation Factor High RE Case
Hydropower	15,386	15,386	37.97%	38.46%
Solar	314	2,214	19.56%	14.44%
Wind	760	4,120	51.39%	43.51%
HFO	836	836	12.46%	0.03%
LNG	962	1,262	26.28%	0.63%
CH4	30	30	27.86%	0.65%
Geothermal	1,025	1,328	57.79%	4.44%
Bioenergy	262	337	44.08%	10.93%
Battery	0	250		7.19%
Total	19,575	25,762	35.86%	27.53%

The key informants opined that the high levels of dispatch and utilisation of wind and solar are also a consequence of the overestimation of capacity installation for Ethiopian wind and solar in their generation expansion plants. They argue that this was an overly ambitious plan that was not in tune with the real demand and investments as of the end of 2025. The informants additionally raised the issue of ensuring that power plants that were already built needed to be fully utilised to ensure the recovery of investment and benefits. From this

perspective, the expansion of wind and solar generation required to be staggered to avoid overinvestment.

The wind and solar utilisation factors of 43.51% and 14.44%, respectively, in the high VRE case are consistent with the global capacity factors (IRENA, 2023). The dispatch allocation in the simulation is realistic. Therefore, the dispatch findings are not only relevant to the research questions of this study but also directly inform the quantitative parameters of the CfD and geothermal dispatch recommendations in Chapter 5.

The low utilisation of geothermal power plants was also viewed as a concerning outcome of the modelling process. Geothermal is a dispatchable renewable energy resource. The utilisation findings of the simulation have direct implications for the LCOE of each technology in the EAPP. This will influence the strike prices required in CfD arrangements to make new investments financially viable. In the high-VRE case, the geothermal utilisation factor of 4.44% implies an effective LCOE far above the global average of USD 3,478/kW reported by IRENA. This would mean that new geothermal investments would require price support. However, low utilisation levels for HFO, LNG, and CH₄ plants have been documented in the literature (Heptonstall & Gross, 2020) and by key informants.

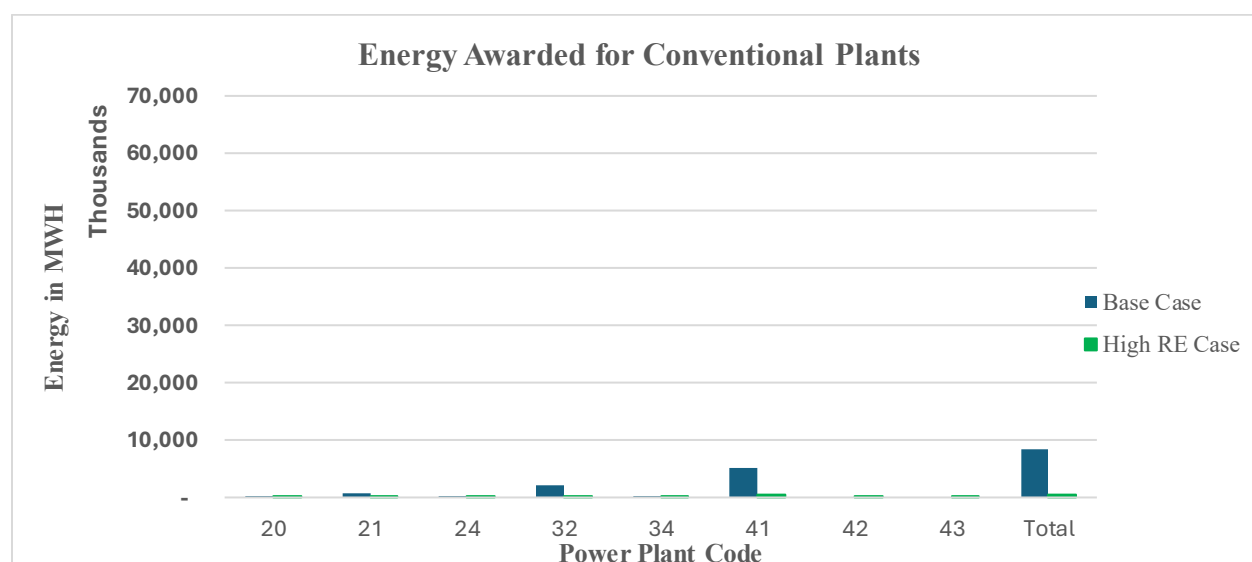
4.4.2.2.2. Conventional Power plants

Conventional power plants in this study were HFO, LNG, CH₄, and geothermal power plants. These power plants were awarded 13.69% and 0.94% of the 61.49 TWh and 62.56 TWh in the EAPP market in the base and high-RE cases, respectively. This is shown in **Figure 4-41**. This indicates that, even in the base case, with infinite transmission conventional plants would operate in a limited manner. This operation is further minimised in a high VRE scenario.

This is a generally expected result because of the higher generation costs of conventional plants, especially hydrocarbon-based power plants.

Figure 4-41

Energy Awarded to Conventional Plants



The handling of dispatch from geothermal power plants is a concern. The key informants cautioned that geothermal power plants are a RE) source that should be prioritised. This is the case in Kenya, where geothermal power plants operate as baseload plants, although wind and solar have first right of dispatch whenever available. The informants warned that when these power plants are curtailed, steam is vented, a resource that is expensive to prospect and develop. In the model, geothermal plants experience curtailment of 41% and 95.5% in the base and high RE scenarios, respectively. This is expected from a wholesale market operation, where the marginal cost of generation is the only consideration for the right of dispatch. The inability to enforce a constraint in AMIRIS to force the dispatch of geothermal at certain minimum levels made it impossible to enforce dispatch.

The investment in geothermal generation in the EAPP, the fact that geothermal is renewable, and that steam is a costly resource, will mean that a regulatory intervention is required to allow geothermal plants to dispatch at higher levels. The levels can be decided on both commercial and technical terms. Commercially, this could be achieved via a vesting or CfD arrangement, as described in Section 4.4.2.1, to ensure that the prioritised dispatch of geothermal does not distort marginal market pricing.

The concept of a ‘must-run’ condition in a wholesale market is related to the need to ensure the technical stability of the grid, observe regulatory and contractual obligations, environmental and cogeneration requirements, and cater for physical and operational constraints. These must-run units are exempted from the prevailing wholesale pricing and are paid special rates to retain them online. As such, the EAPP wholesale market cannot be idealistic but would need to be adjusted to the specific conditions of the grid or pool to accommodate these concerns. The simulation considered that all capacity installed in the EAPP was open for participation in the pool. In practice, there would be a need to observe bilateral arrangements between countries and within utilities and generators in-country. These bilateral arrangements and technical requirements of the country-level grids will force the utilisation of contracted conventional and renewable plants before resorting to the wholesale market. Additionally, transmission constraints between countries will result in quasi-islanding of the countries and a need to operate conventional power plants to ensure supply. The utilisation of conventional power plants will therefore be higher in practice.

4.4.2.2.3. Bioenergy Plants

The bioenergy power plants considered in this simulation comprised bagasse-, biogas-, methane-, and peat-based power plants. Bioenergy power plants contributed insignificantly to

the energy in the EAPP, as illustrated in **Figure 4-42**. These power plants were awarded 1.64% and 0.51% of the energy dispatched in the base and high RE cases, respectively. This conforms to the expectations of the research, as from the generation data, bioenergy plants in the EAPP do not have significant installed capacities. However, they will receive prioritised dispatch over conventional plants because of their cost benefits and renewable nature. The simulation software is designed¹³ to support bioenergy projects that are often community-based and support agricultural waste management. Although bioenergy plants are few in the EAPP, they receive a preferred dispatch in the simulation.

In the EAPP and much of the developing world, bioenergy resources, such as firewood, are a primary source of energy for cooking and agricultural processing activities. The availability of biomass in the quantities and quality required for consistent dispatchable generation is not guaranteed, as is the case in Germany. Globally, the establishment of robust and sustainable supply chains for solid biomass remains to be a challenge (Ahmed et al., 2025). The choice of feedstock for bioenergy production also affects the sustainability rating of the generated electricity.

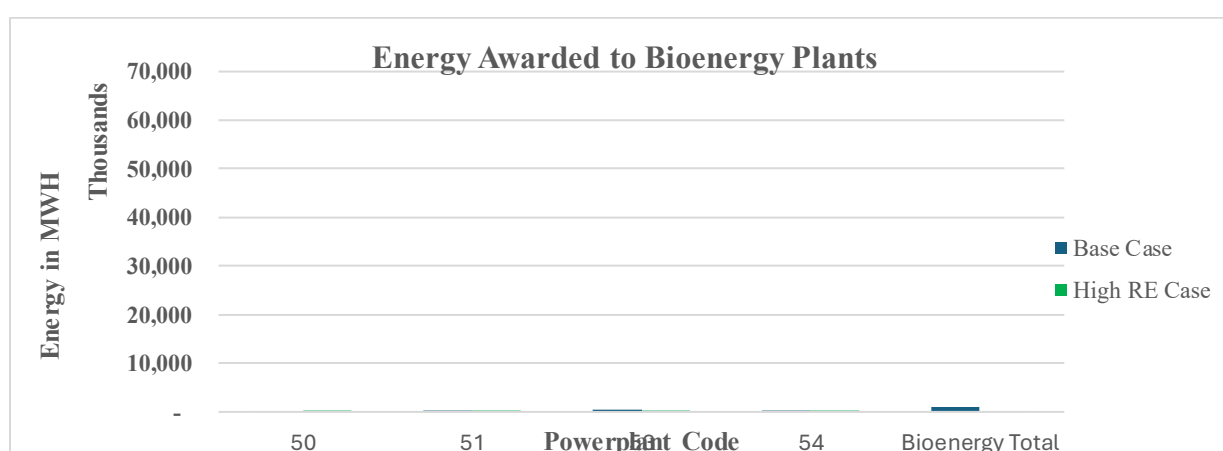
Bioenergy in the form of biogas and methane is most commonly used for electricity generation. This is the case for methane-based electricity production in Rwanda from Lake Kivu (Mbakop, 2024). Methane is produced in large volumes under Lake Kivu, which is shared with the DRC, an EAPP member (Boehrer et al., 2019; Sadeghi & Hassanzadeh, 2025). These plants have a steady supply of feedstock and operate much like conventional plants.

¹³ The simulation software is based on the European (German) market that gives priority support to bioenergy generation. Such a support policy is also foreseen to be necessary in EAPP for solid biomass based plants.

Additionally, bagasse from sugarcane production is commonly used for power generation in sugar factories in Kenya and Uganda (Fashina et al., 2018; Kabeyi & Olanrewaju, 2022; Rotich et al., 2024). These plants rely on sugarcane waste availability, which is affected by seasonality. Power plants are prone to feedstock scarcity.

Figure 4-42

Energy awarded to bioenergy Power plants



The differences in the operations of bioenergy plants imply that a more nuanced, project-specific approach is required to determine their operations in a wholesale EAPP market.

4.4.2.2.4. Battery Storage Powerplant

The simulation included a 250 MW battery installation in the high RE case. The simulation showed that battery installation would result in a commercial loss of EUR 193 million. This negative economic return for the battery system is an expected outcome of the simulation, especially considering the high installation of RE resources and the generally high reserve margin. Battery installation is not required given the availability of different generation sources in the pool and the ability to move power without capacity constraints. However,

battery installations are expected to be beneficial in supporting various renewable energy power plants with instantaneous supplies during periods when dips in supply are experienced.

4.4.2.3. Stability of supply

In a pure energy market, such as the one modelled for the EAPP, there is a need to provide sufficient financial support for power plants that supply capacity to the market. These would be provided by conventional plants that can be called upon at any time to ramp up or down in response to grid demand. There is a need to compensate the fixed capital costs and operational and maintenance costs for power plants that provide capacity to the electrical system. This invariably calls for the development of a capacity remuneration mechanism. This could be achieved through capacity auction schemes for short-, medium-, and long-term capacity or through a direct fee for the provision of capacity, as is the current case in the EAPP utilities.

These capacity payments can be availed by both generators who can increase their supply at short notice and consumers who can reduce their demand at short notice (consumers with interruptible supply). There is also an option to mandate the provision of capacity by large consumers or producers at certain times and costs, with the option of being penalised if they do not. These are capacity obligation schemes (NECOM, 2024).

4.4.2.4. Ancillary Services

This study does not consider ancillary services required to support the penetration of VREs. The high penetration of VREs will necessitate the supply of ancillary services by other technologies. These ancillary services must be factored in when evaluating the cost of supply from VREs and must be traded in a balancing market and value and compensation provided for the powerplant supplying the service. The simulation does not model separate ancillary

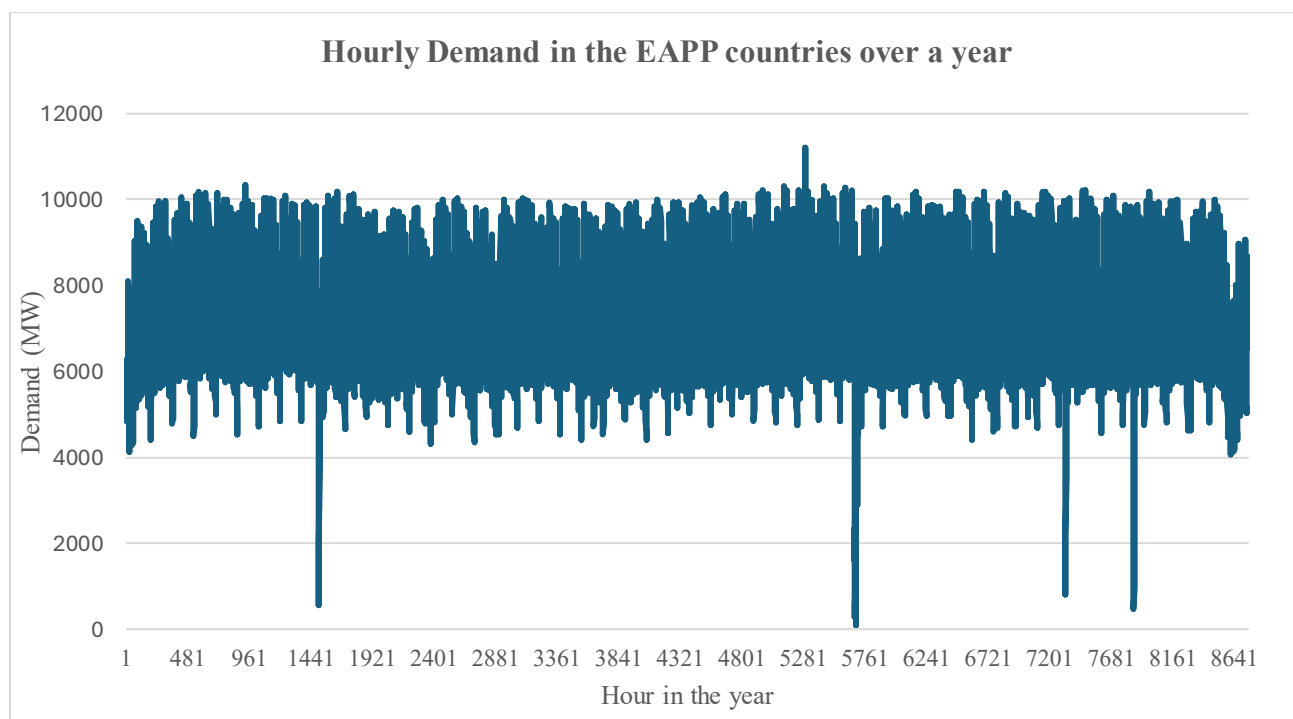
services or balancing markets. This is necessary to ensure grid stability and the quality of supply to consumers considering the successful deployment of high quantities of VRE sources.

4.4.2.5. Planning reserve Margin and Curtailing of Generation

The peak demand for EAPP from the data was 11.21 GW, with a profile, as illustrated in **Figure 4-43**. This contrasts with an installed capacity of 19.57 GW in the base case and 25.76 GW in the high RE case. This implies that the reserve margin was 43% and 56%, respectively. This is a high level compared with the recommended reserve margin levels of 15–30%. This implies that there would be a significant amount of idle capacity at most times of the year. This would have associated costs that the market would have to compensate investors for, increasing overall prices.

Figure 4-43

Demand in the EAPP for the modelled year



In terms of curtailed energy, there is a 65% and 98% curtailment of the conventional plants in the base and high RE cases, respectively. This is a very expensive undertaking, given that these plants mostly already exist and would receive capacity compensation to continue operating.

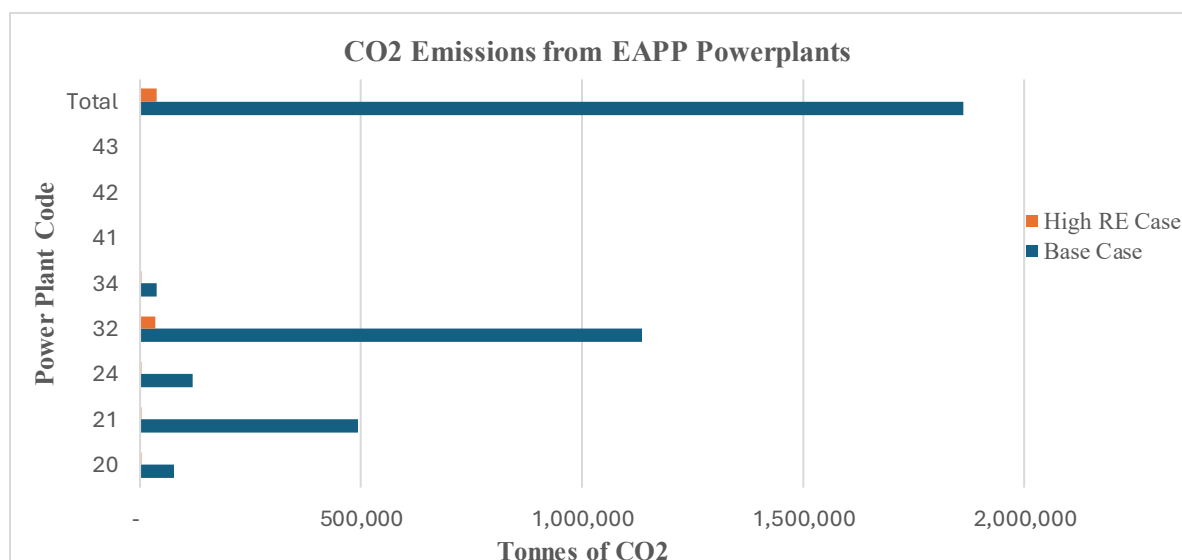
A properly planned generation expansion should result in lower levels of curtailment and reasonable reserve margins. Otherwise, consumers of the EAPP would pay for unutilised capacity in a capacity market, as varying RE plants would receive priority of dispatch in the market owing to lower marginal generation costs.

4.4.2.6. Fuel Consumption and CO₂ Emissions

CO₂ emissions related to electricity in the five EAPP countries are driven by the generation of HFO, LNG, methane, and peat. In the base case, the five EAPP countries grids were found to have an annual carbon emission of 1.8 million metric tons of CO₂eq. In the high-RE scenario, this reduced significantly to 37,000 tonnes of CO₂eq. This is depicted in **Figure 4-44**. The sharp reduction is attributed to the increase in RE generation in the high-VRE case. This is an expected outcome of the wider penetration of VREs, which have a near-zero marginal cost of generation compared to thermal sources, which have marginal costs driven by their fuel costs.

Figure 4-44

CO₂ emissions of the conventional Power plants in the EAPP market



The reduced dispatch from the thermal plants will also imply a sharp reduction in fuel consumption commensurate with their reduced levels of awarded energy, as observed in **Figure 4-11** and **Figure 4-12**.

The reduced dispatch of thermal plants does not imply that they are not needed in the electrical system. In contrast, the increased penetration of VREs necessitates the availability of fast-reacting generation technologies that can provide capacity and system inertia. LNG, HFO, methane, and hydro plants are required to support the grid during fluctuations in wind and solar power plants. Thermal plants will also continue to play an important role in providing peaking reserves for the grid. A sharp reduction in dispatch and consequent reduction in CO₂ emissions are expected.

4.4.2.7. Market Power in the EAPP

Applied to the simulated EAPP market, the Herfindahl–Hirschman Index for the installed generation capacity in the base case would be approximately 3,000. This is more than the 2,500-threshold used by competition authorities to classify markets as highly concentrated. Ethiopia's share of 52% and 59% of total installed capacity in the base and high VRE scenarios, respectively, influences this.

Under a Stackelberg-type leadership dynamic, Ethiopian generators could exploit their first-mover advantage to set effective price floors. Smaller generators in Kenya, Uganda, Tanzania, and Rwanda would be price-takers. This structural risk is not captured in the AMIRIS simulation, which models all agents as symmetric marginal-cost bidders. The simulation results represent an upper-bound welfare estimate. A real market with strategic bidding would likely produce higher prices and less efficient dispatch than the model. Regulatory mitigation, including mandatory cost-based bidding in the market's early phase, real-time market monitoring, and capacity withholding penalties, are essential structural features of the EAPP day-ahead market design (Ranci et al., 2013; Stoft, 2015).

4.4.3. RQ3: How accurate is the model developed for short-term trading?

The quantitative assessment of the model's accuracy yielded a positive correlation with the measured statistics of the regulator in Kenya. The qualitative check revealed various themes that needed to be addressed by the simulation. These include the inaccuracy of the assumption of infinite transmission and the lack of modelling of the political factors in the EAPP. These issues were grouped into main themes, as described below.

4.4.3.1. Main Themes to be Addressed from the Key Informant Interviews

The research received invaluable comments from a pool of key informants who brought in different perspectives not directly covered by the model and simulation. These include the effect of transmission bottlenecks in enabling the activities of the pool, the effect of politics on decision making given the five governments involved, standardisation of technical codes, financial system readiness, and VRE production quotas, among others. In this section, the research delves into these matters.

Infinite Transmission and Congestion: The assumption of an infinite transmission capacity was viewed as having a significant impact on the results of the simulation. Interviewees believed that the lack of modelling of different transmission capacities and constraints would not allow for the true cost to be derived. This view was expected but was not seen as having the possibility of leading to lower prices. Constraints in transmission capacity between countries are expected to lead to higher overall prices in the EAPP.

The assumption of an infinite transmission capacity also allows for maximum transfers of energy between countries, a situation that may not be realistic. Currently, the EAPP has limited transfer capacities between countries, as described in **Table 3-2**.

These capacities define the maximum power that can be transferred between any two countries. The chosen software, AMIRIS, did not allow the modelling of transmission capacities between countries. In this study, the entire EAPP was modelled as one market zone.

This finding from the key informants corroborates existing literature on the need to manage congestion (Kumar et al., 2005; Pillay et al., 2015; Reichenberg et al., 2023; Yusoff et al., 2017). Congestion is a manifestation of non-infinite transmission capacity and the cost of apportioning access to transmission.

Geopolitics, political decision-making, and the potential effects of the EAPP: A common concern is the necessity of political harmony among member states and devising means of shielding the pool from geopolitics and intercountry political issues. The widespread failure of power sector reforms in many countries can be attributed to not considering their political realities. The power sector is seen as an instrument of government policy, and its performance affects the social and economic programs of the respective governments (Barnett, 2014). Decisions made in the power sector reform processes have a fundamental impact on the public and their interests. It is foreseeable that any move toward pooling of electricity and further in-country market reforms would have political influence.

In power pools, the equating of local generation sources in the territory of a given country ensures energy security. However, this may lead to inefficiencies in the economic cost of the country and draw resources away from other development needs. The political costs in a pool that need to be addressed include providing one country political power over another, involving countries in the internal affairs of other countries, creating political costs in protecting a line from interference by local groups, providing an excuse for political oppression in the route of regional transmission lines in favour of regional over local priorities (Barnett,

2014). The impact of political objectives on optimal electricity generation and transmission in the SAPP was reviewed. The study examined the optimal trade-offs between CO₂ emissions, system expansion costs, and electricity sovereignty for different political risk scenarios. It found that there was a swift monetary trade-off between electricity sovereignty and CO₂ emissions and that solar PV will dominate the pool if environmental and political considerations are factored (Trotter et al., 2017).

Political considerations will play a significant role in the success of the EAPP and affect the penetration of VREs. The existing local political contexts must be mapped, and the development of the power pool must be adjusted to the existing political environment. This will enable buy-in in the EAPP and allow for faster progress. Once a framework is agreed upon and implemented, the pool will need to be independent of the political establishments of Eastern African countries.

Prinsloo (2019) argues that the SAPP has been successful as SADC has allowed it to focus on energy cooperation with little interference. He argues that efficient and effective management of the SAPP coordination centre has boosted trust among member countries and attracted development partners. Regional interests have dominated national interests. The SAPP also benefits from being a regional powerhouse in South Africa, with other countries not competing. This is not the case for the EAPP, with contests for dominance in the energy sector between Kenya, Ethiopia, and Egypt. However, national interests also dominate regional energy integration in the SAPP, with countries rushing to secure bilateral agreements to meet their own energy security needs. Smaller countries with resource constraints are, however, benefiting from access to the SAPP market to further solidify the bankability of cross-border

projects developed in these countries. The availability of development finance has also greatly advanced the development of the SAPP.

The success of the EAPP will also depend on the decentralisation of the institutions of the pool, as observed in the SAPP. This process has already begun with the establishment of the seat of the regional regulator in Uganda and the EAPP secretariat, which is to become the system operator in Ethiopia.

Apportionment of VRE development quotas: The interviewees expressed concerns regarding the manner in which renewable energy development would be undertaken. There were concerns that countries might want to ensure their own energy security as a matter of national interest and may not want to be fully reliant on the pool. This concern was particularly acute in countries with political disputes. It was also considered that countries with the bulk of the supply may consider satisfying their local demand before exporting to the pool during times of scarce supply. This may leave other participants without supply and result in economic losses. The prioritisation of national interests in the pool is an expected position by market participants and must be considered in market design.

There was the suggestion to have a quota of allocation of renewable energy development related to the EAPP market. Further, this quota for the development of renewable energy potential could be linked with the in-country electricity demand and overall EAPP generation expansion planning framework. This allocation, a technical and economic consideration, will need to be viewed in the context of the political economy of the pool. Enabling countries to secure national interests while advancing regional integration. Technologies that are prevalent in all countries will likely be dominant, as all countries will have a chance to develop their home-based resources.

An alternative approach to solving the national interest issue is used in the SAPP that could also be instructive for the EAPP. The SAPP has a methodology for prioritising projects with those that have higher multi-country involvement and projects where excess generating capacity was made available for trading in the pool, thereby receiving a higher score. These are the projects the pool then supports in implementation and enables access to finance. The scoring system is as shown in **Table 4-8**.

Region-wide regulation and standardisation of technical parameters: There was concern regarding the need to standardise regulations. The establishment of a regulator in Uganda, as noted by key informants, shows that the process is ongoing. The regulator would have to define codes for the system, market, transmission, and generation operations. These would allow for standardisation of operations over the entire EAPP region, covering 16 countries

Financial system readiness: The readiness of the financial system in EAPP countries to financially settle each clearing member was increased. The market clearing system and banks of the respective market participants will need to be connected. Communication should be conveyed between the market clearing and the point of actual settlement of the trade in the bank accounts of the trading parties. Banks will need to support the speed of transactions required to settle participants financially. A lead time for payments must be defined. The EAPP could borrow from the experience in other markets such as the SAPP, Singapore, the EU and the US wholesale markets

Region-wide regulation and standardisation of technical parameters: There was a concern raised on the need to standardise regulation. The establishment of a regulator in Uganda, as noted from the informants, shows that the process is ongoing. The regulator would

have to define codes for the system, market, and transmission and generation operations. This would allow for standardisation of operations over the entire EAPP region, covering 16 countries.

It is also necessary that as the power pools converge into a single African electricity market, similar codes be developed, or existing codes be adapted for the entire continent. The EAPP could borrow from the SAPP, which is more advanced and is planned to be connected to the EAPP.

Table 4-8

Scoring system to prioritise projects in the SAPP

	Criteria	Weight (%)	Weak (1)	Below Standard (2)	Standard (3)	Above Standard (4)	Best (5)
1	Project size (MW)	15	<50	50 - 200	200 - 500	500 - 1000	>1000
2	Levelized costs (USD/MWh)	25	>=131	101 - 130	71 - 100	41 - 70	<= 40
3	Availability of associated Transmission infrastructure (km of lines needed)	10	>750 km	101---750 km	50---100 km	<50km	0
4	Economic impact (descriptive)	10	Little impact, limited to small area	National Impact only --- jobs, >GDP	Mainly national impact --- jobs, >GDP and some regional benefit	Balance between regional and National impact	Mainly regional Impact --- jobs, >GDP
5	Commissioning date (year)	10	After 5	After 4	After 3	After 2	After 1
6	Share of capacity already committed (%)	10	<20	21 - 35	36 - 50	51 - 80	81 - 100
7	Share of capacity available for regional	15	<20	21 - 35	36 - 50	51 - 80	81 - 100

	Criteria	Weight (%)	Weak (1)	Below Standard (2)	Standard (3)	Above Standard (4)	Best (5)
	trade after commissioning						
8	Number of participating member countries (#)	5	1	2	3	4	≥ 5

Note. Data was sourced from (Prinsloo, 2019)

4.4.3.2. Qualitative Findings relative to theory

The qualitative findings showed significant convergence with the theoretical frameworks established in the literature. They qualify the theory in the Eastern African context. Three theoretical bodies are considered in this discussion from the points of departure and alignment. These include electricity market design theory, political economy theory, and VRE integration theory.

4.4.3.2.1. Market Design Theory

Alignment

Key informants affirmed that a day-ahead EAPP market would reduce the average cost of electricity through merit-order dispatch. This is consistent with foundational market design theory which states that competitive short-term markets produce more efficient welfare outcomes (Kirschen & Strbac, 2018; Rudnick & Velasquez, 2018; Stoft, 2015). The key informants' expectation of a hybrid bilateral-and-day-ahead structure mirrors the transitional pattern in developing country electricity market reforms (Rudnick & Velasquez, 2018).

The informants' concern that conventional and geothermal plants would not recover fixed costs through energy-only revenues in a low-price VRE market is consistent with the 'missing money' problem (M. Hogan, 2017; Stoft, 2015). The informant's proposal that

capacity remuneration mechanisms be developed alongside the energy market aligns with literature (D. R. Biggar & Hesamzadeh, 2025). Though energy-only markets are also advocated in some literature (W. W. Hogan, 2005).

Points of Departure

A minority of informants argued that shorter contract durations would drive higher investor prices rather than lower system prices. This was in the context that fixed costs would need to be recovered over shorter timeframes than under a 20-year PPA. This view is not supported by the simulation or the theoretical literature on marginal cost clearing (Stoft, 2015). This is however consistent with project financing literature.

Separately, the informants' preference for developing individual country markets before pool integration contrasts with the theoretical argument that regional markets can themselves substitute for national market (Oseni & Pollitt, 2016; Vanheukelom & Bartelsmann-Scott, 2016). This departure likely reflects a practical political assessment, not a rejection of the theoretical proposition.

4.4.3.2.2. Political Economy Theory of Regional Energy Integration

Alignment

Informants consistently raised the risk of Ethiopian dominance in the EAPP, given Ethiopia's 52.3% share of total installed capacity in the base case. This maps directly onto political cost framework and documentation of Ethiopia's exercise of influence over EAPP members (Barnett, 2014; Elabbas, 2023a). The finding that technical decisions are regularly overridden at the ministerial level confirms characterisation of the EAPP as a political organisation that needs greater secretariat autonomy (Elabbas, 2023a). The informants' reference to the SAPP as a model aligns with theory on delegated institutional authority is as

determinant of pool success (Oseni & Pollitt, 2016; Prinsloo, 2019). The informants' VRE quota proposal, linking development quotas to national demand and the EAPP generation expansion plan, aligns with the SAPP scoring methodology (Prinsloo, 2019). This mechanism ensures regional interests are aligned with national ones.

Points of Departure

The informants' have a more positive view of the prospects of the EAPP. This is likely due to their active roles in the EAPP. Political economy literature is more cautionary arguing that the political costs of power pools are systematically underestimated (Barnett, 2014). Ineffective governance structures has been noted as a persistent weakness across African power pools (Elabbas, 2023a). This divergence reflects a selection effect. It also suggests that the political constraints are not regarded by those closest to the process as insurmountable. Researchers are however sceptical.

4.4.3.2.3. *RE Integration Theory*

Alignment

The simulation results confirm four theoretical predictions of VRE integration. These are the declining average prices through the merit order effect, increased frequency and depth of negative pricing, declining utilisation factors for dispatchable generation, and growing requirements for flexibility services (Holtinen et al., 2012; Owolabi et al., 2023; Sewalt & De Jong, 2003). The informants confirmed that high VRE penetration depresses the prices that VRE generators themselves receive. This is well (Brown & Reichenberg, 2021; Reichenberg et al., 2023) 2021; Reichenberg et al., 2023). The recommendation for CfDs as the primary investment protection instrument aligns with the theoretical and policy consensus (Ason & Dal Poz, 2024).

The identification of ancillary services as a critical unmodelled gap is consistent with the literature (Banshwar et al., 2017; Holttinen et al., 2012; Perez-Arriaga et al., 2017).

Points of Departure and EAPP-Specific Extension

There is departure from the existing theoretical literature concerning the tension between variable and firm renewable generation. Wind and solar on one hand, geothermal on the other. The VRE integration literature, dominated by European and North American contexts, frames the integration challenge primarily as a tension between variable renewables and fossil fuel-based conventional generation. The more acute tension in the EAPP is between VRE's and geothermal. VRE technologies bid near zero marginal cost and geothermal plants while technically renewable, carry high capital costs and variable costs. These make them commercially vulnerable to curtailment by VRE in a merit-order marginal market. This renewable-versus-renewable framing represents an original contribution of the research.

The informants' qualification that the severity of negative pricing in the high-VRE case reflects overestimated Ethiopian expansion plan capacity rather than a realistic near-term scenario also extends the theoretical literature. VRE integration theory predicts negative pricing as an expected outcome but does not account for the systematic overoptimism of expansion plans in developing countries (IRENA, 2023) . The optimal VRE sensitivity scenario provides a methodological tool for applying this adjustment within a simulation framework.

4.4.4. Alignment of Qualitative and Quantitative findings

This section examines the alignment and points of departure between the simulation and the key informant findings. It is organised according to the three dependent variables. Points of convergence are identified first, followed by the specific misalignments and their analytical implications (Ivankova et al., 2006; McCrudden & McTigue, 2019) .

4.4.4.1. Electricity Pricing

Alignment

Both the qualitative and quantitative findings confirm that a day-ahead EAPP market would produce lower average prices than the current bilateral PPA structure. Both findings confirm that negative pricing would occur and agree on its cause as zero-marginal-cost supply meeting price-inflexible demand, as in literature (Sewalt & De Jong, 2003).

Misalignment: Direction of pricing for investors

A minority of informants argued that wholesale market conditions would force higher prices because generators would need to recover fixed costs over shorter period. This contradicts both the simulation and the theoretical literature on system marginal clearing prices. The misalignment arises because the two sources are measuring different constructs. The simulation produces the system marginal clearing price, while the informants are describing the minimum viable price from a project finance perspective. The absence of long-term offtake certainty in a wholesale market raises the cost of capital. This may increase the break-even price for new investment even as the marginal clearing price falls. The simulation does not model this distinction, and it remains an unresolved gap.

Magnitude and realism of negative pricing

There is a divergence in the magnitude of negative pricing. The simulation finds negative prices in 77% of hours in the high VRE case, a level the literature characterises as extreme (Owolabi et al., 2023; Seel et al., 2021). The informants attributed this severity to the overestimation of Ethiopian VRE capacity in the national expansion plans. They view the high-VRE case as a hypothetical extreme rather than a prediction. The optimal VRE sensitivity scenario supports this position. It finds that the market sustains a positive mean price if additions are limited to 18.6% of the high VRE increment. Systematic overoptimism in national expansion plans is well-documented in developing country contexts (IRENA, 2023). This misalignment highlights the need to apply a deployment realism adjustment when using expansion plan figures in simulation-based research.

4.4.4.2. Dispatch of Power Plants

Alignment

The qualitative and quantitative findings agree that renewable energy dominates dispatch in both the base and high VRE cases. The simulation awards 85% and 99% energy to REs in the base and high-VRE cases respectively. The marginal costs of wind, solar, and hydro place them at the front of the merit order (Rudnick & Velasquez, 2018). This is a clear point of convergence across the quantitative, qualitative, and literature findings.

Misalignment: Geothermal curtailment

The simulation produces a geothermal utilisation factor of 4.44% in the high-VRE case. Key informants rejected this as operationally and commercially unrealistic. They noted that geothermal steam vented during curtailment is a costly, irreversible loss. This is also a stance in literature (Dobson, Ayling, et al., 2020; Dobson, Dwivedi, et al., 2020b). Informants argue

that fixed costs cannot be recovered at 4.44% utilisation, and Kenyan geothermal already operates as baseload under the existing bilateral framework. The misalignment arises because the simulation applies the standard European ABM treatment of geothermal as a conventional market participant. This does not reflect EAPP conditions.

The geothermal must-run sensitivity scenario was run directly in response to this qualitative finding. The must-run scenario confirms that dispatch priority for geothermal is feasible without fundamentally distorting the merit order.

4.4.4.3.Stability of Supply

Alignment

The simulation and the key informants agree that a larger, regionally pooled generation fleet improves supply security by enabling countries with surplus capacity to support those in deficit. This also aligns with literature (Prinsloo, 2019; Vanheukelom & Bartelsmann-Scott, 2016).

Misalignment: Infinite transmission and supply security

The simulation's finding that ceiling-price hours disappear entirely in the high VRE case was rejected by informants as result of the infinite transmission assumption. They argued that actual transmission constraints would trap generation surpluses and deficits geographically. It is confirmed from literature that several EAPP interconnections are limited to a few hundred megawatts (as depicted in **Table 3-2**). The literature supports the informants affirming that ignoring transmission constraints significantly overestimates supply security benefits(Perez-Arriaga et al., 2017; Pillay et al., 2015). This is the most important qualification on the simulation's findings for policymakers. Incorporating nodal or zonal pricing with

explicit transmission capacity constraints is identified as the highest-priority improvement for future modelling work in this research.

Misalignment: Battery storage value

The simulation returns a net commercial loss of EUR 193 million for the 250 MW battery installation. Informants argued that the energy-only model omits the ancillary services revenue. These are from frequency regulation, voltage support, and black start capability. These they argue constitutes a significant portion of real-world battery value. This is a methodological misalignment as the two sources assess the same asset against different value streams.

Literature documents the growing importance of storage in providing system services that synchronous conventional generation previously supplied (Banshwar et al., 2017; Holttinen et al., 2012). Co-optimisation of energy and ancillary services is essential for accurate storage valuation. The EUR 193 million loss should therefore be understood as a lower bound on commercial position rather than a reliable net estimate.

CHAPTER 4.5: SUMMARY

Chapter four of the research started with a check of the trustworthiness of the data used in the research, the reliability and validity of the data. The results of the simulation were then laid out and an evaluation of the findings undertaken. A summary of this approach is given here below.

4.5.1. Trustworthiness of Data

The simulation data were drawn from official national generation expansion plans of the five EAPP countries, supplemented by resource timeseries data from the Global Wind Atlas and Global Solar Atlas. The national plans were treated as trustworthy as official government documents, with the caveat that the documents used were current as of 2023 and may have been updated since. The VRE resource timeseries represent annual averages and do not capture extreme weather events. Hydropower and bioenergy timeseries were adapted from the AMIRIS German reference scenario, introducing a known approximation for the EAPP context that is acknowledged as a limitation of the simulation.

4.5.2. Research Findings by Research Question

RQ1: How is electricity traded globally and in Eastern Africa?

Electricity trade in the EAPP is currently conducted through long-term bilateral PPAs between utilities, with no operational short-term market. The Kenya-Uganda interconnection operates a power exchange at a fixed tariff, and the Kenya-Ethiopia connection is governed by a take-or-pay bilateral PPA. Key informant findings confirmed that the region is actively developing a day-ahead market under the EAPP framework, with market rules under

development. A regional regulator has been established in Uganda, and market operation software under procurement. The market was expected to go live in 2026.

The EAPP was compared with the SAPP, which operates both day-ahead and balancing markets but faces challenges of market depth and infrastructure aging. The EAPP, by contrast, has surplus generation capacity in several member states that provides a favourable starting condition for short-term trading. Key informants noted that a hybrid market structure would likely persist for an extended period, with legacy bilateral contracts coexisting alongside the new short-term market.

RQ2: How would the introduction of more variable renewable energy affect wholesale electricity markets in Eastern Africa?

The simulation involved six scenarios being run for the EAPP. Two main scenarios (base and high-VRE), one validation (Kenya 2023) and three sensitivity scenarios (medium-VRE, optimal VRE, geothermal must-run).

In the base case, the annual mean market price was +67.5 EUR/MWh, with 556 hours at the ceiling price of 1,500 EUR/MWh indicating supply insufficiency at peak. In the high VRE case, the ceiling price hours disappeared entirely as additional capacity eliminated the supply shortfall, but the mean price collapsed to -295.6 EUR/MWh, with negative prices occurring in 77% of the year. VRE plants supplied 85% and 99% of awarded energy in the base and high VRE cases, respectively. Conventional plant dispatch fell by 93%, CO₂ emissions fell by 98%, and geothermal utilisation dropped from 57.79% to 4.44%.

The medium VRE sensitivity scenario, constructed at the exact midpoint of the base and high VRE capacity additions (+2,773 MW), produced a mean price of -83.2 EUR/MWh,

confirming a non-linear price-penetration relationship. The merit-order inflection point, where new VRE capacity begins to erode prices even during peak demand hours, occurs between the base and medium VRE levels: 41% of the fourth demand quartile hours already return negative prices in the medium VRE case. The evening peak at 19:00 remains commercially viable at +841 EUR/MWh in the medium VRE case, preserving investment signals for dispatchable generation and storage.

The geothermal must-run sensitivity scenario confirmed that assigning priority dispatch to geothermal plants within the high VRE configuration increases the frequency and depth of negative pricing without fundamentally distorting the merit order for other technologies. An average price of -335 EUR/kWh is achieved.

The optimal VRE capacity scenario identified a scaling parameter of $\alpha = 0.186$, meaning the market can absorb approximately 18.6% of the high VRE incremental capacity before the mean price turns negative. The Ethiopian wind and solar capacity ceiling consistent with a positive mean price is 914 MW and 310 MW respectively, governed by a price-capacity budget of $0.068 \times W_{\text{add}} + 0.087 \times S_{\text{add}} \leq 67.5$.

The negative pricing findings prompted analysis of regulatory interventions including contracts for difference, feed-in premiums, and capacity remuneration mechanisms. CfDs were identified as the most appropriate instrument for the EAPP context, providing price support for VRE investors without creating a blanket subsidy. A staggered approach to VRE capacity deployment, guided by market price signals and aligned with actual demand growth, was identified as the most effective means of avoiding the overinvestment scenario represented by the high VRE case. Battery storage in the high VRE case produced a net commercial loss of

EUR 193 million, reflecting the absence of revenue from ancillary services that are not captured in the energy-only market model.

RQ3: How accurate is the model for the EAPP?

External quantitative validation using a simulation of a Kenya 2023 scenario against official Kenyan 2023 grid data produced a 0.58% deviation in total dispatched energy from EPRA statistics, establishing the model's credibility for EAPP simulation. The qualitative validation through key informant interviews produced eight themes that confirmed the broad directional findings and identified specific limitations of the model.

The most significant model limitations identified were the assumption of infinite transmission capacity, which key informants viewed as producing optimistic supply security outcomes and artificially low pricing in the EAPP; the modelling of geothermal as a conventional market-bid plant, which produces unrealistic curtailment levels; the exclusion of ancillary services, which causes the model to undervalue storage and flexibility resources; and the use of Ethiopian generation expansion plan figures for wind and solar, which key informants considered overly optimistic relative to actual deployment prospects.

4.5.3. Qualitative Findings Relative to Theory

The qualitative findings show strong convergence with three theoretical bodies: market design theory, political economy theory of regional energy integration, and VRE integration theory. Key informants confirmed the theoretical prediction that wholesale markets produce lower average prices and more efficient dispatch than bilateral contracting, while also surfacing the missing money problem for high-capital-cost plants in an energy-only market.

The political economy findings, particularly the concern about Ethiopian dominance, the importance of political insulation for the pool, and the proposal for VRE development quotas, are consistent with theoretical predictions about distributional tensions and sovereignty concerns in regional energy integration.

The VRE integration findings extend the theoretical literature by highlighting the specific tension between variable and firm renewable generation in the EAPP context, a dimension less prominent in the European and North American literature that informs most VRE integration theory.

4.5.4. Alignment of Qualitative and Quantitative Findings

The quantitative and qualitative findings confirm strong directional alignment on the effects of integrating VRE into a regional electricity market. A day-ahead EAPP market would produce lower average prices than the current bilateral operation. This would be driven by dispatch of zero-marginal-cost renewables. Negative pricing would occur when zero-marginal-cost supply meets price-inflexible demand. Contract-for-difference arrangements are recommended to protect investors. Renewable energy dominates dispatch in both base and high-VRE scenarios. Regional pooling of generation capacity improves supply security by allowing surplus countries to support those in deficit.

Despite this alignment, five substantive misalignments exist stemming from structural features of the simulation. A minority of informants argued that wholesale markets would force higher prices for investors, as the absence of long-term offtake certainty raises the cost of capital. Informants also viewed the simulation's extreme negative pricing results as a consequence of overestimated renewable capacity figures and rejected near-total geothermal

curtailment as commercially unworkable. This informed the geothermal must-run sensitivity scenario. This confirmed that dispatch priority for geothermal is feasible. The simulation's assumption of unlimited transmission capacity was seen as significantly overstating supply security benefits. Real interconnection constraints would trap surpluses and deficits geographically. Finally, the simulation's commercial loss estimate for battery storage was considered a lower bound, as it excluded ancillary services revenue.

CHAPTER 5 IMPLICATIONS, RECOMMENDATIONS, AND CONCLUSION

CHAPTER 5.1: INTRODUCTION

This chapter presents the implications of the research findings, the policy recommendations arising from the study, and the conclusions drawn in response to the three research questions. It also identifies areas for future research and situates the study's contributions within the existing body of literature on short-term electricity markets and variable renewable energy integration in developing-country power pools.

This final chapter is structured as follows. Section 5.2 presents the implications of the research organised by the three research questions, including the study's limitations, its alignment with the theoretical framework, and its contributions to the literature. Section 5.3 sets out five policy recommendations for application in the EAPP. Section 5.4 proposes five areas for future research. Section 5.5 concludes the research with a summary of findings and a statement of the study's academic and practical contributions.

CHAPTER 5.2: IMPLICATIONS

This section describes the implications of the research. The limitations of the study that may have affected the interpretation of the results are discussed. The results are described in terms of how they respond to the study problem, align with the purpose of the study, and the conceptual framework of the research. The significance of the results and how they contribute to the existing literature are also described. The conformance of the results to the existing literature is checked, and the implications for practice are described. The section also describes how the research findings build on the existing body of research. The section is organised according to the three research questions.

5.2.1. RQ1: How is electricity traded globally and in Eastern Africa?

This study explored how power is traded in the EAPP, considering the five countries of Kenya, Uganda, Ethiopia, Tanzania, and Rwanda. The findings from the pool of experts revealed that, in the current state, the approach described in the literature is similar to what is being undertaken in practice. However, there is little literature describing the state of the power sector in the EAPP, with the literature focusing more on the developing world and some countries of the EAPP (Oseni & Pollitt, 2016; Rudnick & Velasquez, 2018).

The region is still dominated by bilateral trade between countries, although some markets, such as Kenya, are moving toward wholesale markets. The EAPP is also advancing the launch of a day-ahead market with structures in place to advance this, including a regulator being set up and grid codes and market protocols being developed. The literature and key informant interviews also confirmed the advancement of the transmission line infrastructure needed for trade to occur in the region.

Further interviews with regional key informants would add more information to the literature on the EAPP. Respondents in the key informant interviews provided updates on the state of development of the EAPP and the issues of concern. There was also an acknowledgement of the advancement of other regional pools, such as the SAPP, which had advanced further than the EAPP. The SAPP was already trading on a day-ahead market across its member countries.

The EAPP does not currently have provisions for private sector involvement in trade, as indicated by the available literature. At the time of the research, the pool comprised only national utilities as members. From the key informant interviews, it was understood that there are movements to allow access to the pool for private sector generators and traders. This will be part of the agenda for the ministerial committee meetings at the end of 2024.

This study revealed the need to manage political influence in the decisions and approaches of the EAPP. Indeed, the literature agrees that this is an issue hindering the advancement of the EAPP (Prinsloo, 2019). The research made recommendations based on how the SAPP handled political interference in pool operations. The SAPP was cited in the literature as being successful at this by having a dominant country, South Africa, that drives demand and is the main buyer in the pool. This is in contrast to the EAPP, where Egypt, Kenya, and Ethiopia were reported to be competing for influence.

The member countries of the participants of the SAPP were the same as those of its main governing body, the SADC, whereas the EAPP, whose main body is COMESA, did not have all its members as members of COMESA. The latter's case means that a ministerial committee was set up and is the main decision-making body of the EAPP, a political one. In contrast to the SAPP, SADC allows the secretariat to run independently on more techno-economic considerations than political ones. The participation of the private sector, an

independent secretariat, and funding from development finance institutions in the SAPP was also cited as important factors in its successful operations.

The research shows that EAPP is moving toward integration into a wholesale market. The countries in the pool have varied levels of liberalisation in their grids but are working together to establish a platform for regional trade. This will enable the trade in excess and deficit with neighbours and allow for the deployment of more renewable energy projects. The research also showed the countries' ambitions to develop more renewable energy sources. The ability to trade will result in lower prices, as described in the following section. This will support lower-end consumer prices and increased penetration of renewable energy, conforming to SDG7 of the sustainable development goals of the UN.

The activation and furtherance of regional trade, however, require care to insulate it from the adverse effects of political posturing by member states and to accommodate the political concerns of member countries.

5.2.2. RQ2 How would a wholesale electricity market in Eastern Africa be affected by introduction of more varying renewable energy?

To investigate the effect of VREs on penetration in an EAPP market, we ran an AMIRIS wholesale market model simulation. The model revealed results that responded to the problem statement and significance of the results. This research aimed to investigate the effect on electricity pricing levels, penetration of RE, demand risk for private investors, and generally to add to the body of work on EAPPs. The simulation findings on electricity prices, allocation of energy to different technologies, and balancing of the demand-supply situation were analysed.

5.2.2.1. Electricity Prices

The research found that electricity prices would be reduced in a short-term market of the EAPP. This finding conforms to the expectations from the literature on power pools, leading to lower electricity prices. The results further showed a worrying trend of negative electricity pricing, which may be good for consumers in the pool but would likely not attract investments in new generation capacity. This is especially prevalent in the high renewable scenario run in the simulation with higher levels of wind and solar power introduced to the grid.

The research recommends that some minimum levels of pricing be introduced to limit the levels of negative pricing and attract investments in generation. The use of contracts for differences to ensure that investors are adequately compensated to guarantee returns and attract interest in investing in power plants is also recommended. This recommendation conforms to what is applied in other jurisdictions, as described in the literature. The base pricing in a CfD scheme is defined as the strike price. This price is recommended to conform to the LCOE numbers described by IRENA, plus an allowable rate of return to ensure a minimum pricing level. A feed-in-premium or one-sided CfD could be used to ensure that investors are left whole, while consumers are not stuck with high prices.

Another possibility for controlling negative prices is to plan expansion properly to ensure that existing resources are fully utilised before new power plants are developed. The simulation applied the expected generation numbers from the generation master plans of the region for the period up to 2025. This had some unrealistic expansion targets for wind and solar, relative to the growth in demand, which would directly imply negative pricing. This would be driven by excess supply in certain instances rather than available demand. In practice, the EAPP would need to control the level of generation expansion relative to demand.

However, this can also be self-regulated by investors receiving timely and accurate signals on the demand-supply situation and pricing for power in the pool before they decide to invest in generation.

The research modelled the EAPP as a single zone with a perfect transmission interconnection, with no limitation on the amount of power that can move between countries. This is not the case, and the difficulty in transmitting power from one country to another based on transmission capacity inadequacies may lead to congestion and higher negative prices for generation stranded in one country. This could imply higher prices than the negative pricing seen in the simulation. However, the countries of the EAPP are progressing the construction of transmission lines, as reported in the literature and informant interviews, and the achievement of the ideal levels of interconnection will expose the market to the likelihood of negative pricing.

Electricity prices are also likely to be influenced by incumbent generators in various countries and the pricing levels of their generation. The management of this risk by vesting contracts, as documented in the literature for markets in transition, was suggested. This would keep consumer prices low by minimising the influence of the pricing of these generators on the marginal pricing of the wholesale market.

The EAPP region is endowed with abundant renewable resources, including wind, solar, hydro, and geothermal. However, investments in generation are needed to exploit these resources. Controlling negative pricing is significant because it enables the attraction of investments into the region, which would lead to more renewable energy on the grid and lower average electricity prices than the currently prevailing prices, to the benefit of the region's consumers.

5.2.2.2. Penetration of Renewable Energy

The research found that RE technologies would be preferred to other sources of generation in the wholesale market. This is mainly driven by the lower marginal pricing from the VREs. Hydroelectric, wind, and solar power plants would dominate the energy awarded to power plants. These technologies together would contribute 85% and 99% of the energy delivered in the base and high RE scenarios, respectively. This directly implies that a wholesale market would favour dispatching RE technologies, as indicated in the literature and observed in practice.

This would, however, imply high curtailment for geothermal, HFO, LNG, and methane-based power plants. These technologies would experience utilisation levels lower than 5 %, with the last three having utilisation levels lower than 1 %. As most of these conventional power plants are already constructed and have contracts based on take-or-pay arrangements (the utility will pay the generator for the available power capacity, whether it is utilised or not), the proper utilisation of available resources becomes a consideration. These plants must be allowed to recover their fixed capital and operation and maintenance costs. These power plants also provide load-following capacity to the grid that VREs can not provide. The simulation does not include an ancillary services market in which such power plants would play a significant role. Such a market is necessary to ensure grid stability and the quality of supply in a high-VRE penetration grid.

The handling of dispatch from geothermal plants was seen as an issue. High penetration and dispatch of wind and solar with a near-zero marginal cost would lead to significant curtailment of geothermal power plants, as observed in the literature and from informant feedback sessions, particularly for the Kenyan grid. Geothermal is a renewable energy source that is a base-load plant but is more accurately modelled as a conventional plant because of its

characteristics. Its main fuel is steam delivered from the depths of the earth. The research implies the need for a regulatory intervention to ensure that geothermal plants are allowed to dispatch their power at higher levels to be a base-load and better utilise the steam resources that are costly to develop. To avoid undue influence over the marginal market price, existing geothermal plants were recommended to be absorbed via vesting contracts, and any new plants through CfDs.

Bioenergy-based power plants and battery energy solutions were marginal contributors to the EAPP dispatch. This was expected, as they have the smallest installed capacities. It should be noted that the bioenergy modelling in this study is confined to grid-connected electricity generation plants and does not capture the dominant role of biomass in household cooking and agricultural energy in EAPP countries. The study also does not account for the associated land use impacts and CO₂ implications of continued dependence on traditional biomass in countries with low grid-based renewable energy penetration. The relationship between grid-scale VRE development and the broader household energy transition is a separate research question that falls outside the scope of this study but warrants attention in the context of SDG7 and regional climate commitments.

The simulation showed high reserve margins of 43% and 56% in the base and high RE cases, respectively. This compares with 20% to 35%, as recommended by the IEA. This means that overall, there is an overinvestment in generation in the region, and demand is lagging. These investments were paid for by the market, which would imply underutilisation of investment. This overcapacity in the high RE case is contributed by higher-than-installed levels of solar and wind in the Ethiopian generation expansion plan for the year 2025. The research

however also has the limitation that it does not consider demand external to the 5 modelled EAPP countries. This may reduce the actual levels of reserve margin.

Overall, as expected from the literature, the EAPP wholesale market would result in higher penetration of renewable energy sources. The provision of ancillary services and sustainable utilisation of invested resources in conventional power plants must be factored in the planning. The levels of VRE on the grid must also be optimised. This can also be achieved through appropriate market signals to potential investors.

In this study, three sensitivity scenarios were used to extend and refine the findings. The medium-VRE scenario demonstrates that the relationship between VRE penetration and market pricing is nonlinear. Adding the first 2,773 MW of capacity reduces the mean price by 151 EUR/MWh, whereas adding the second equivalent tranche reduces it by 212 EUR/MWh. At the medium-VRE level, 41% of peak demand hours return negative prices. This indicates that the market pricing challenge materialises at lower penetration levels than the binary scenario (base-high) comparison suggests. The optimal VRE capacity scenario identifies the point at which the annual mean price crosses zero. The market can absorb approximately 18.6% of the additional high VRE capacity planned in the national expansion plans before the average price turns negative.

For Ethiopia, which accounts for the bulk of the high VRE increment, this translates to a sustainable wind capacity ceiling of 914 MW and a solar ceiling of 310 MW at 2025 demand levels. These findings directly inform the recommendations for VRE investment optimisation in Section 5.3.2.

5.2.3. RQ3: How accurate are the adapted model and simulation findings for the Eastern Africa Power Pool?

The verification of the simulation approach and results was the subject of the final research question. This was addressed via key informant interviews and validation of the model based on Kenyan grid and regulator statistics for 2023.

The informants found the modelling of the EAPP using the AMIRIS model insightful and generating results that are helpful for the furtherance of the EAPP. The resulting dominance of VRE on the EAPP grid was seen as expected and significant in promoting the further exploitation of regions RE resources. The negative prices seen in the simulation were viewed as expected but undesirable because of the likelihood of not attracting investors to build power plants. This expectation was understood in the context of the research assumptions, such as a pure marginal price-based dispatch on the pool. There was an understanding that regulatory intervention would be needed for technologies such as geothermal, as well as to ensure the optimal expansion of generation.

The main themes addressed as shortcomings of the research were transmission-line assumptions, the effect of political interests on the EAPP, and VRE production quotas.

The assumption of an infinite transmission capacity was identified by the key informants as the most significant limitation of the simulation. It is also the misalignment between the quantitative and qualitative findings with the greatest implications for the supply-security conclusions. The simulation finds that ceiling-price hours disappear entirely in the high-VRE case. The key informants rejected this as a consequence of the infinite transmission assumption rather than a reliable prediction of real-market conditions. They argued that the EAPP's limited interconnection capacities would confine generation surpluses and deficits geographically. This would then result in simultaneous oversupply in some countries and

undersupply in others during peak hours. The implication is that the supply-security improvement shown in the high-VRE case can only be understood as an upper bound achievable only under conditions of unconstrained power transfer. Once transmission constraints are incorporated, the outcomes would be less favourable. This is the highest-priority limitation to be addressed by future modelling work.

Qualitative validation also revealed four further misalignments between the simulation and EAPP operational realities. The finding on geothermal curtailment was rejected by informants as commercially and technically unrealistic, given the high sunk costs of geothermal development and the irreversible loss of steam. This motivated the development of a geothermal must-run sensitivity scenario.

The severity of negative pricing in the high-VRE case was attributed partly to the overestimation of Ethiopian VRE capacity in the national expansion plans. This qualification is supported by the optimal-VRE scenario findings. The commercial loss of EUR 193 million estimated for the 250 MW battery installation understates the true value of storage because the energy-only model excludes ancillary services revenue. Such revenue constitutes a significant portion of real-world battery economics. A minority of informants also argued that wholesale market conditions would produce higher rather than lower investor prices. This is a valid distinction between system clearing prices and project finance break-even prices. The simulation does not model project finance metrics. These misalignments collectively define the boundaries within which the simulation findings should be interpreted. They also form the agenda for future research.

The informant feedback did recommend alternative models that could be utilised in future research with different advantages and disadvantages. These included the IRENA

flextool, GAMS, Balmorel, and Valoragua. These could be considered in a future extension of the research. The AMIRIS model was also in the process of developing a module to integrate transmission capacities between different pricing zones.

The informants viewed that the simulation and modelling did not factor in political considerations. Accurate modelling was seen to necessarily include the interests of the different countries in the power pool. These interests were corroborated by the literature and included the energy security of the respective countries. The implication of this finding is the need to factor in the modelling of energy security concerns by including preferences for local generation. This could mean instituting quotas for the development of renewable energy among the countries in the power pool.

Considering the political interests of different countries may lead to a loss of efficiency in electricity pricing and limitations on the size of VRE projects and the attendant benefits of economies of scale of larger power plants. This could result in higher electricity prices in the pool due to distributed generation across the pool. However, the energy independence of each country would be better secured, and harmony among the members of the EAPP would be more likely. However, this approach would be a drawback to the wider integration of the pool.

The continual integration of the pool into a scenario, as the model assumes, was also investigated. The EAPP had appointed a regulator and developed grid and market codes. It was noted that the model operations largely conformed to the anticipated operations of the EAPP. This lends credibility to the key findings of the research.

CHAPTER 5.3: RECOMMENDATIONS FOR APPLICATION

Research into the penetration of various renewable energy sources in the EAPP, given a short-term wholesale market operation, revealed some key issues that would benefit from policy intervention and contribute to the development of the EAPP market system. This section describes five policy recommendations that would enhance the success of the EAPP market. These include the establishment of minimum pricing levels for energy in the pool, the prioritisation of geothermal technologies for dispatch, a policy on how to transition existing generation interests and contracts, the development of a policy on the optimisation of the development of RE technologies vis-a-vis existing plants to ensure better utilisation of power plants and resources, and a recommendation for the development of the pool while factoring in national interests and geopolitics.

5.3.1. Set Positive Minimum Pricing Levels in the EAPP Market

The prices available in an electricity market affect the likelihood of attracting investment in electricity generation. Investors in power plants are required to cover their fixed and variable costs and earn a reasonable return. No market design can induce suppliers to sell below their average production cost (Stoft, 2015).

The simulation results indicate that the EAPP market in the base and high RE cases would experience negative pricing levels for 1979 h and 6792 h per year, respectively. This is equivalent to 19% and 78% of the time in the two cases. These negative prices are contributed by the near-zero marginal cost of generation for wind and solar, compounded by a reduced level of demand during off-peak hours in the EAPP grid. The high RE scenario indicates a significant increase in the instances of negative prices, culminating in an average price of -

295.57 EUR/MWH compared with 67.5 EUR/MWH in the base case. This shows that there is no incentive to build power plants in the high RE case, as there would be no income for generators that would allow them to recover their fixed and variable costs, much less a reasonable return. In practice, in wholesale markets, negative prices occur when the marginal generator would rather continue generating and paying a price rather than reduce its output (Seel et al., 2021).

In the simulation, the price is determined by a combination of feed-in-tariff (for power plants that this is assigned), fuel costs, plus capacity charges (for conventional plants), and marginal pricing (for power plants without support structures and reliant on the market for clearing). In addition to setting the minimum negative price and the maximum positive pricing levels, no regulatory intervention on pricing is considered.

The situation in the model is not feasible for high RE, and regulatory or policy intervention would be required. An approach that considers both incentivising investments and insuring consumers from price shocks (Hirth et al., 2023). They proposed a dynamic tariff with price hedging. An annual volume of consumption, an hourly consumption profile, and a price are set for consumers for a contractual period of one or more years. If the consumer consumes as much electricity as agreed, they only pay what was contractually agreed. If the consumer does not consume as agreed, the hourly excess is reimbursed or billed at the spot market price. However, this approach is suitable for a more complex, smart-metered grid, which the EAPP is not.

Negative pricing can also be interpreted as a signal to increase demand or reduce supply. This indicates a lack of flexibility on the demand or supply sides of the market (Halbrügge et al., 2024). Consequently, another solution is to stop running flexible generation or increase

demand from flexible loads during times of negative pricing. This would, however, highlight the issue of the utilisation levels of power plants. The ramping up and down of demand would also require the availability of flexible loads in the system. These are loads that can be increased or decreased in terms of electricity consumption to match the requirements of the grid. This is itself an ancillary service that can be compensated. Optimising the volume of installed RE would also reduce negative pricing and is the subject of discussion in the next section.

The research, given the situation of the EAPP, recommends the establishment of a minimum pricing level for the wholesale market (price hedging), that is, greater than zero and equivalent to the lower of the LCOE of wind and solar, as defined by IRENA, such as in IRENA (2023), and adjusted to the average risk in Eastern Africa. This arrangement would increase the certainty of generator revenue and enable the financing of power plants. It would additionally protect consumers from a higher floor price, likely vested with incumbent generators, applying to new generators, retaining this gain for consumers.

It is acknowledged that a minimum price floor of this nature constitutes an indirect subsidy for generation investors. This is justified by market failure. In the EAPP, the absence of long-term offtake certainty in a wholesale market elevates the cost of capital for new-generation projects. Market price signals alone are insufficient to attract the private investment needed to expand VRE capacity. The subsidy should be bounded, transparent, and temporary. This can reduce in value as VRE technology costs continue to decline or as demand growth absorbs surplus capacity.

5.3.2. Optimise the Levels of RE Investment vis-à-vis Existing Investments

Electricity is generated using different technologies, including conventional and VRE technologies. Given the investments already made in EAPP countries and the aspirations to shift to a greener generation profile, there is a place for different generation technologies to curb climate change. Fixed costs have already been incurred, and contractual obligations are running as markets shift to more renewable sources.

Given that financial resources are scarce in the EAPP region and governments have competing demands, there is always a need to ensure the maximisation of the utilisation of invested resources and the application of the most optimised mix of generation technologies to supply electricity to consumers in the region. This need also applies to private investments. It is necessary to ensure that they are directed to the most impactful areas for the economies of the EAPP and that they do not add costs to consumers in terms of return requirements.

The simulation, especially in the high RE case, revealed a low level of utilisation of power plants in the region. VREs led comprising onshore wind, hydropower, solar and bioenergy plants were utilised at 43.51%, 38.46%, 14.44% and 10.93% respectively. In contrast, conventional plants were utilised at very low levels. Geothermal, methane, natural gas and heavy fuel oil plants were utilised at 4.44%, 0.65%, 0.63% and 0.03% respectively. These are very low levels of utilisation for investments in the hundreds of millions of Euros.

Furthermore, the planning reserve margins for the region were found to be 43% and 56% in the base and high renewable cases, respectively, compared with the recommended levels of 20% to 35% by the IEA. In the US, the NERC recommended levels of the planning reserve margins were reported to be between 13% and 17% (Reimers et al., 2019). The high levels of the planning reserve margin from the simulation represent a situation of uneconomic

use of resources, although this also implies higher reliability. Market participants would be liable to pay for this and it would affect the pricing of electricity in the wholesale market. Alternatively, with these levels of utilisation and planning reserve margins, investors would not invest in power plants in the EAPP wholesale market, as returns would not be guaranteed.

The optimal-VRE capacity sensitivity scenario run for this study provides a quantitative basis for the recommendation that utilisation and reserve margin figures alone cannot supply. The scenario identifies the level of additional VRE capacity at which the annual mean market price crosses. For Ethiopia, the dominant contributor to the high VRE scenario, this translates to an optimal wind capacity addition of 590 MW above the base case and a solar capacity addition of 310 MW. Beyond these levels, at current demand, the mean market price turns negative, and investment signals deteriorate. The scenario also establishes a price-capacity trade-off. For every additional megawatt of Ethiopian solar beyond the optimal, 0.79 MW of wind must be removed to maintain a positive mean price. This capacity optimisation that balances technology mix, market price signals, and demand growth. is required for EAPP generation expansion planning. This research provides an initial methodological template for more comprehensive multi-country optimisation research.

The planning reserve margin in a pool should be carefully derived to ensure that the pool regions, in the case of the EAPP, are not individually left with levels lower than the recommended levels (J. Lin et al., 2018). This is especially necessary where transmission constraints exist, as in the EAPP. The availability of export markets outside the pool allows for higher planning reserve margins.

Thus, it is necessary to optimise the system costs, reliability, and CO₂ emissions. This implies optimising the proportional levels of conventional versus renewable generation. This

is corroborated by the existing literature on this topic. The Colombian electricity sector has considered cost-based generation competition between renewables and conventional plants to minimise system costs, CO₂ emissions, and the number of blackout events (Henao et al., 2019). It was found that a higher proportion of solar photovoltaic (PV) was promising for a reduction in the overall system costs and the ability of the system to cope with extreme weather. Research has been undertaken on the optimal embedding of VRE, focusing on wind, to reduce generation costs, reserve capacity requirements, and environmental emission reductions (C. X. Guo et al., 2012). They found that the integration of onshore wind power would increase the generation cost and the need for reserve capacity but decrease emissions. However, the technology costs of wind power have reduced significantly in the intervening years (IRENA, 2023).

The 95th percentile weighted average total installed cost of onshore wind in Africa was reported to be USD 2110/kW. The 95th percentile¹⁴ global weighted average for solar PV was reported to be 1878/kW. The global weighted average cost of geothermal energy in 2022 was USD 3478/kW, while the global weighted average cost of hydropower was USD 2881/kW. The 95th percentile global weighted average cost for bioenergy was USD 6539/kW (IRENA, 2023).

These numbers indicate that for every underutilised or excess 100 MW power plant of geothermal, onshore wind, solar PV, and biomass, the market cost is 347 MUSD, 211 MUSD, 187 MUSD, and 653 MUSD, respectively. These are huge sums that the EAPP countries may not want to lay idle and that investors would not spend on idling plants reliant on the wholesale market without capacity payments.

¹⁴ The bulk of the African power plants had costs within the 95th percentile

Thus, this research recommends that careful optimisation of existing and planned generation technologies in the EAPP corresponding to the regional demand growth be undertaken to ensure the optimal expansion of generation in terms of financial and environmental costs and grid stability. This optimisation should prioritise each country having a requisite minimum planning reserve margin first, before optimisation at the pool level.

5.3.3. Prioritise Dispatch for Geothermal Power Plants

Geothermal plants are mostly operated as baseload plants in the EAPP, specifically in Kenya, where the bulk of the EAPP fleet is located. According to the simulation results, the geothermal plants experienced curtailments of 41% and 95.5% in the base and high RE cases, respectively. This was because of the reliance on the marginal cost of generation as the only metric in determining the dispatch of power plants. Thus, wind and solar energy ended up displacing geothermal energy as a source of generation. This observation is consistent with the observations of the Kenyan market regulator for the geothermal fleet, which experienced curtailment due to the availability of hydro, wind, and low grid demand (EPRA, 2024). This displacement is also consistent internationally as observed from literature (Dobson, Dwivedi, et al., 2020b; Millstein, Dobson, et al., 2021)

The topic of flexible generation from geothermal sources has developed as a new school of thought given the increase in VRE sources and the occurrence of negative pricing in wholesale markets. Modifications have been undertaken in the geysers geothermal plants in US to enable flexibility allowing them to reduce production by 350 MW for 4 to 5 hours. This flexibility must however be cognisant of the potential dangers to well integrity (Dobson, Dwivedi, et al., 2020b). Similar considerations of flexibility apply to nuclear power plants in high-VRE environments (Loisel et al., 2018).

Curtailment of geothermal plants in U.S. energy markets during periods of negative pricing increased the energy value by 1 to 2 USD/MWh (Millstein, Dobson, et al., 2021). This, when combined with increased production during high-priced peak hours, could potentially double the value increase to 4 USD/MWh. This value represents the price of electricity at the network node where the geothermal plant is connected.

The provision of flexibility, however, will require further investments in geothermal plants, which will expose the plants and, especially, the steam field to further risks. This means that prioritising dispatch from existing and future geothermal plants should be undertaken in the EAPP over wind and solar plants. Geothermal, having the quality of a baseload plant, being renewable, and having much heavier investment costs (USD 3478/kW) should be prioritised in dispatch.

5.3.4. Implement Vesting Contracts for Incumbent Generators and Retailers

The transition to a wholesale market implies the need to ensure continuity in contracting and honouring contractual relations until the end of tenure. The introduction of a wholesale electricity market must consider the role played by existing power plants and the contractual arrangements of the off-takers and customers with the retailer. Incumbent generators fear the insolvency of the incumbent off-taker due to customer defections in a wholesale market. Utilities also fear their inability to honour long-term contracts signed with generators, given the risk of losing customers to other retailers.

The proposed prioritisation of geothermal power plants and continuation of existing generation assets into the wholesale market has the potential to distort marginal prices in the wholesale market and potentially open avenues of rent-seeking by incumbent generators. This risk can be overcome, and the transition to a wholesale market can be enabled by the use of vesting contracts (Kee, 2001b; Rudnick & Velasquez, 2018). Vesting contracts provide a hedge for the price of power to incumbent generators, allowing other parts of the market formation to move faster.

Vesting contracts were seen to enable four desirable outcomes in a wholesale market, in the analysis of the missteps of deregulation in the California energy market (Kee, 2001a). These included the provision of financial hedges, behavioural modification of market participants, minimisation of interference with the spot, contract, and retail markets, and the achievement of other regulatory objectives. The provision of a financial hedge is clear and the most important benefit of vesting contracts.

Market behaviour is controlled by vesting contracts that fix the price at which incumbent generators are compensated. This removes any incentives to push prices higher, as

that benefit would not be passed on to the generator. The generator will also be incentivised to agree on a hedging contract that considers outage requirements for the maintenance of the power plants. Vesting contracts, however, would deny generators extra revenues from times of high spot prices.

Vesting contracts would also ideally extend to incumbent retailers that are currently regulated through cost-of-service regulation in the EAPP. This is necessary to manage the transition to a wholesale market, as these retailers would be required to serve customers at fixed, predetermined prices while still operating in and buying from a wholesale market. Retailers are incentivised to manage loads to ensure profitability at the vesting contract price. The availability of flexible loads with related compensation for providing flexibility will allow retailers to maximise market opportunities. However, the regulator will require a high level of deregulation that allows them to incur losses and retain profits from trade in the market.

Vesting contracts would replace the need for price caps that cover unhedged utilities exposed to the spot market, while catering to the need to attract new investments motivated by uncapped pricing. This is particularly important for infrequently run peaking plants.

Vesting contracts are provided for a limited period, typically in response to the time required to achieve full market operation. In the interim, before full market-based operation, an incumbent generator has a mix of market-based and vesting contracts. Once the vesting contract term expires, a power plant can participate directly in the market. This phasing of the implementation of vesting contracts allows for the gradual entry of new participants (retailers and generators).

Regulatory approval from competition regulators may be required to ensure that any anticompetitive effects of vesting contracts that are opposed to direct public benefits due to deregulation and wholesale competition are mitigated (Kee, 2001a).

5.3.5. Develop policies considering geopolitics and national interests.

The results of the key informant interviews showed the need to consider the development of power pools from the perspective of political interests. The main political interest is energy self-sufficiency and avoidance of being hostage to a neighbouring country in energy supply or export. There are also political costs related to power pools that can arise from the need to rationalise tariffs, protect regional infrastructure, such as transmission lines, and prioritise them over local ones, and involvement or exposure of one country in the internal affairs of the other due to shared infrastructure (Barnett, 2014).

The EAPP, like other power pools, is an offshoot of a regional organisation that has focused on energy. Regional trade organisations have been the launchpads for trade in electricity as an additional commodity for trade (Oseni & Pollitt, 2016). The EAPP was originally formed by agreements between member countries but was later adopted by COMESA (Elabbas, 2023a). However, non-COMESA members, such as Tanzania, are members of the EAPP. This complicates COMESA's ability to politically control the EAPP. Consequently, the EAPP has a politically driven governance structure headed by the council of ministers of the member countries.

Major state-owned monopolistic utilities in power pools will hide under the national interest to maintain their dominance in the market, while those that are less dependent on the regional pool join in defensive positions to prevent their exclusion from the market and its decisions. Large utilities are reported to be reluctant to concede their sovereignty to a higher authority. An example is cited of Egypt blocking the EAPP regional master plan because it included the Ethiopian grand renaissance dam that Egypt did not want built. Ethiopia is said to have a strong utility interested in power trade, dominating decisions, and marginalising other

members (Elabbas, 2023a). The challenge of Egypt, Kenya, and Ethiopia vying for dominance in the EAPP is also noted (Prinsloo, 2019). The insistence on centralising EAPP institutions in Addis Ababa by Ethiopia in opposition to and blocking of Egypt's request to host the regulator and Rwanda's request to host the market operator is also cited (Oseni & Pollitt, 2016). The dominance of state-owned utilities and the lack of participation of the private sector in the EAPP further cement the dominance of political interests in the pool.

The experience of the SAPP has been that the availability of funding from development partners has proven crucial in pushing forward the development of the pool. The proper management of the pool by the SAPP operator has attracted more funding from development partners, which has propelled the pool. The existence of transmission interconnections of high capacity in the SAPP and direct linking of the SAPP and SADC, including similar membership, and the dominance of South Africa with no apparent challengers has smoothed the development of the SAPP. The participation of the private sector in the SAPP has also led to faster development. The private sector acts as a key pressure group and introduces competition that results in lower costs, increased investments, and diversification of energy sources.

The EAPP should adopt a framework for apportioning VRE development quotas among member countries. This can be linked to each country's share of regional demand aligned with the pool-wide generation expansion plan. This addresses the core political economy tension identified by the key informants, that is, the risk that dominant generation countries capture the bulk of VRE revenues, while smaller countries remain dependent on imports. It also provides a basis for equitable benefit-sharing, consistent with regional integration objectives. The SAPP project scoring methodology, which prioritises projects with multi-country involvement and

high regional trade availability, offers a directly applicable model for the EAPP (Prinsloo, 2019).

The EAPP secretariat should be granted delegated authority over technical and commercial decisions. This directly addresses the structural constraints identified in the literature and was confirmed by key informants (Elabbas, 2023a). The requirement for ministerial-level resolution of technical questions delays market development and exposes the pool to geopolitical interference. Decision-making protocols that distinguish between policy and technical and commercial matters should be developed and adopted as a priority for governance reform.

The EAPP should open participation to independent power producers and private generators. This is consistent with the practices of the SAPP and WAPP. Private sector participation introduces commercially motivated actors whose interest in efficient market operation counterbalances the national interest posturing of state-owned utilities. They increase market liquidity and diversify the sources of financing for new generation investments.

CHAPTER 5.4: RECOMMENDATIONS FOR FUTURE RESEARCH

This section proposes some areas for future research that would build on the current research. This research was conducted under a certain set of assumptions and the status of development of the AMIRIS model used to undertake the research. The assumptions were necessary to allow the efficient undertaking of the research within the resource constraints. The findings of the research, both the simulations and the key stakeholder interviews, informed the selection of areas of interest that would edify the current research.

The research proposed four areas for future research that will significantly build on the findings and the existing body of work on the EAPP. The first is a simulation conducted with the actual transmission interconnection capacities and congestion costs of the EAPP, including the countries modelled as different zones interacting based on transmission constraints. This is expected to closely mimic current EAPP conditions. The second area of research is the incorporation of ancillary service requirements and markets in the simulation of the EAPP market. Further integration of VREs into the EAPP grid will require ancillary services.

The third area of research is the optimisation of stepwise generation expansion at the pool-wide level. This is a necessary step to ensure resource efficiency and greater utilisation levels for generation facilities. The final proposed area of research is the political economy of the EAPP, considering national interests and their relation to regional interests. The four areas are described in detail below.

5.4.1. Incorporating Transmission Interconnection Capacities and Countries as Zones

The assumption of an infinite transmission capacity between countries applied in this research is not tuned to reality. Transfer capacities across countries are limited by transmission. This study and the AMIRIS model applied to it did not consider limitations in transmission. The AMIRIS model at the state of development used to run the study did not have the capacity to model multi-zone markets. This feature is under development in the model and is available in future simulations.

Although this assumption is not expected to adversely affect the main findings of the research, it is desirable that future research include the transmission capacities available between countries as a limitation on the amount of electricity that can be transferred. Since the state of interconnection in the region is not widespread, and there is a high volume of transfer, bottlenecks in moving capacity between countries are expected. Table 3-2 shows the interconnection capacities between the countries of the EAPP, and thus the constraint expected in 2025 for cross-border transfers. Given the potential for VRE resources in EAPP countries (Wu et al., 2017), further investment in the region's transmission capacity is required.

Transmission bottlenecks imply that countries with higher generation costs (refer to Table 2-1) would experience prices higher than the marginal price in the case of infinite transmission. Countries with lower overall generation costs will likely see stranded or underutilised assets or a lack of investment interests due to the limiting nature of trade possibilities. The development of power plants in different countries, given their own individual dynamics (financing costs, state of transmission infrastructure availability, and regulatory regime), would entail different pricing levels; thus, these countries would not ideally be described as a single zone. This price for bottlenecks in the transmission systems defining congestion costs that need to be added to the cost of supply.

Additionally, modelling the EAPP as a single zone in this study enabled the execution of the simulations and drawing of conclusions regarding the penetration of renewable energy in the EAPP market. However, the countries of the EAPP do not operate as a single zone but as distinct zones. The countries have different pricing levels within their boundaries and only interact with their neighbouring countries based on available transmission interconnection and transfer capacity. Future research should incorporate these differences into a market design that considers inter-zonal differences and the state of transmission interconnectedness and resultant capacity of transfer between countries.

Future research could consider modelling multiple zonal prices that interact with each other at the transmission nodes interconnecting countries that generate different prices at interconnection nodes. Alternatively, each country or zone may have a uniform price defined by a zonal marginal price in its internal market, which forms the basis for trade with other zones at a defined time. Each zone provides an indication of available generation capacity, the price of the generation, the demand for electricity, and the offered prices for supplying electricity into the zone. These four principal data points for each zone could then form the basis for deriving an EAPP marginal pricing level at the given time. This problem was encountered during the integration of European energy markets a decade ago (Biskas et al., 2013, 2014). The European experience can serve as a basis for research into the best alternative for EAPP integration.

Modelling and simulation approaches can be borrowed from research that solves interzonal exchanges considering physical flow limits at the branch in a single multi-zone clearing model, while mixing branch physical flows and inter-zonal exchanges (Vlachos & Biskas, 2019). Additional considerations of zoning beyond the use of national boundaries can be adapted (Ambrosius et al., 2020). This approach argues for fewer optimally configured price

zones defined to ensure the maximisation of social welfare. The available transfer capacities can be chosen to ensure welfare gains and investment incentives.

Future research that considers the state of transmission interconnection and models the countries of the EAPP in zones with defined available transfer capacities is thus proposed to extend the work of this research and refine the expected effect of high penetration levels of VREs considering these constraints.

A related and currently unresolved question is whether congestion pricing in the EAPP should be addressed as a technical or political matter. Technically, zonal or nodal pricing is the established mechanism for incorporating congestion costs into market-clearing prices. The literature demonstrates that it produces more efficient dispatch and investment signals than uniform pricing in constrained grids (Perez-Arriaga et al., 2017; Risanger et al., 2025). However, in the EAPP context, pricing congestion has a political dimension that the technical literature does not adequately address. Assigning a congestion premium to a country for using a neighbouring country's transmission infrastructure introduces sovereignty and cost allocation tensions (Barnett, 2014; Elabbas, 2023a). The experience of the European inter-TSO compensation scheme offers a potential model (Meeus, 2020). However, its applicability to the EAPP's less developed institutional framework is doubtful. Future research on transmission zoning should therefore address both the technical design of multi-zone pricing and the political economy of cost allocation between EAPP member states.

5.4.2. Incorporating an Ancillary Services Market for the EAPP

The penetration of renewable energy in the EAPP grid will increase the need for grid-supporting services. The varying nature of renewable energy power plants, such as wind and solar, and the operational nature of grids imply that ancillary services will be required. Ancillary services increase system flexibility, allowing for more VRE while maintaining system balance (IRENA, 2019). The types of ancillary services required are specific to each grid. It is necessary to define ancillary services from the perspective of the EAPP. The EAPP market, as currently planned, does not have an ancillary market (Elabbas et al., 2023).

Different researchers have defined different ancillary services (Banshwar et al., 2017; Chuang & Schwaegerl, 2009; Z. Zhou et al., 2016). These ancillary services include those that support frequency stability, such as regulating and operating reserves and frequency control power; those for power balancing, including scheduling and dispatch of balancing energy; those supporting voltage control, including reactive power control and tap changer control; those supporting the restoration of supply, including black start capability and islanding operation; and those supporting system management, including power quality assurance, operation, and asset management (Chuang & Schwaegerl, 2009). These ancillary services can be provided by both generation and demand (Z. Zhou et al., 2016).

Reactive power and voltage control, black start, and three operating reserves (instantaneous, regulating, and 10-min) were proposed for the SAPP. It was further suggested that trade in ancillary services between utilities should not negatively affect the reliability of the interconnection and should primarily be technically feasible (Chown et al., 2007). The SAPP is more advanced than the EAPP, and similar research on which ancillary services would be required in the EAPP is necessary.

The levels and cost of supply of these ancillary services required in the EAPP grid are of interest. This research did not include an ancillary services market. An ancillary services market is necessary with a higher penetration of renewable energy to support the grid, given the varying nature of wind and solar. The grid will need to be provided with supporting services from different generators (conventional and renewable) or demand agents with flexible demand.

Today, renewable energy technologies participate in ancillary services markets in both centralised and decentralised applications (Banshwar et al., 2017; Demoulias, Malamaki, Gkavanoudis, Mauricio, Kryonidis, Oureilidis, Kontis, & Martinez Ramos, 2020; Rancilio et al., 2022). The EAPP has the bulk of the VRE's being centralised plants but there is a trend towards decentralisation with the expansion of captive power plants mainly based on solar PV. Faced with the need for ancillary services, grid codes and grid operators require RE sources, such as wind power, to provide balancing services. This is the case in Belgium, Denmark, Poland, and Spain, among others (IRENA, 2019).

The measurability of ancillary services and the ability to quantify them would define how to value and compensate for their supply. Ancillary services that can be provided by distributed RE sources as inertial response, active power smoothing (limitation of ramp rate), primary frequency response, fault-ride through and clearing, mitigation of voltage harmonics, and exchange of reactive power for voltage regulation (Demoulias, Malamaki, Gkavanoudis, Mauricio, Kryonidis, Oureilidis, Kontis, & Martinez Ramos, 2020). Subsequently, a methodology for assigning the costs associated with these ancillary services was defined. Other researchers have also defined the valuation of specific ancillary services offered by batteries (Yamujala et al., 2022).

Ancillary services are procured in three ways (Pollitt & Anaya, 2020). The first is through a condition imposed on a generator as a requirement for connecting to the grid. They argue that this can be compensated at a fixed price or at opportunity cost. The second is via a long-term bilateral contract specific to the supply of the service at a specific location. The third is via bidding in the market using regular auctions six to 12 months ahead.

Research on which ancillary services are relevant for the EAPP, how to procure and compensate for them, and how to optimally include an ancillary services market in the pool is warranted for future research.

5.4.3. Research on Optimal Generation Expansion Scenarios for the EAPP

This study focuses on the penetration of renewable energy into the EAPP with inputs such as various generation expansion plans of the countries of interest. From the findings, the generation plans from various countries may not necessarily define the optimal level of renewable energy required to ensure investments and affordability of the supply. These generation plans can be ambitious and unrealistic regarding the amount of renewable generation that can be added to the grid in each time interval. The further away the projections, the more inaccurate the projected levels of generation. This can be seen in the projections of the last version of the EAPP master plan undertaken in 2014 and the Ethiopian master plan (EAPP et al., 2014; USAID Power Africa, 2021). The projected levels of generation for 2024 are far from being achieved.

Countries in the EAPP currently develop their own individual power development plans. These only consider the internal demand and supply conditions of a country and not the regional balance. These national plans also do not have regional considerations other than bilateral arrangements. The extent of excess or underutilised generation at the regional level is not mapped. The findings from the simulation show high levels of underutilisation of generation. This generation is expensive for the nations of the EAPP to acquire and not maximise.

The optimisation of generation development at the regional level is of interest to research, considering the development of power plants for regional markets and not only for local markets. This should be balanced with the level of utilisation and their cost, while allowing for capacity to undertake regional trade. There is also a need to prioritise expansion projects that have the lowest cost and risk, coupled with the highest impact and accessibility. Wu et al. (2017) describe a possible multicriteria framework that would enable this

prioritisation including availability of transmission capacity, regional resource distribution and accessibility of the given sites. Similar electricity supply and demand scenarios were undertaken for the southern Africa power pool (SAPP) utilising three scenarios, the business as usual, SADC integration and grand deal

The extant literature proposes different approaches to planning for the expansion of generation in the pool (Moghaddas Tafreshi et al., 2012). The optimisation of generation and transmission investments in Southern Africa was estimated to lead to savings of up to 5% in system costs or between USD 2 and USD 4 billion over a 20-year period (Graeber et al., 2005).

Research into the optimal manner to expand generation in the EAPP to ensure low-cost expansion with optimised utilisation levels of the generation and transmission infrastructure is proposed.

The optimal-VRE capacity sensitivity scenario developed in this study provides an initial methodological approach for this type of analysis at the pool level. A scaling parameter that represents the proportion of planned VRE capacity added to the base case is introduced. , The scenario identifies the absorption capacity of the market to the level beyond which average prices become negative. At this level, investment signals are poor. Future regional generation expansion optimisation research could build on this approach by extending it to multiple technologies and countries. It is necessary to incorporate demand growth projections and transmission capacity constraints. This would result in a multi-dimensional optimisation framework applicable to the EAPP planning process at the pool level.

5.4.4. Research into the Political Economy of the EAPP

Research through feedback from the key informants revealed the importance of the political environment in the progress of the EAPP. Although political analysis was outside the scope of the current research, it may be an issue worth investigating in future research. Political considerations affect the success of VRE penetration into the EAPP. The main consideration is the requirement for energy security within different countries and the avoidance of overreliance on one neighbouring country for energy supply. Other secondary concerns include the effects of political relations between different governments, the effect of market operations on the ability to attract foreign direct investments in generation in different countries, the effects of the power pool on the local politics of countries, and the distribution of the opportunity to exploit natural resources for supply to the power pool among countries in the region.

The placement of subsidies to encourage generation and cushion consumption in different markets and how these would be affected by competition at the wholesale market level in the pool needs to be investigated. The effect on the pool of, or lack of, net-zero commitments and other climate change-related commitments of the member countries on generation expansion related to renewable energy needs to be considered. Additionally, the desire for expanded GDP growth and related per capita consumption of electricity at low prices will affect the penetration of RE in the EAPP.

Although these considerations have some technical and economic implications, they are largely political in nature. Building trust in the EAPP is necessary to allow the exploitation of vast renewable energy resources while ensuring that nations perceive the EAPP as a fair platform. A system is needed that allows nations to explore their own developmental ambitions, even as they integrate at the level of the EAPP. Research on the political economy, considering

examples of other power pools in Africa and around the world, on how the aforementioned issues were handled, is required.

Some embedded political issues related to the EAPP have already delayed its progression and will affect the further penetration of VREs (Elabbas, 2023a; Elabbas et al., 2023; Medinilla et al., 2019; Prinsloo, 2019). The main political issue is tensions over the Grand Ethiopian Renaissance Dam, with disagreements between Egypt, Sudan, and Ethiopia. In the past, this has led to the blocking of the master planning process for the EAPP (Elabbas et al., 2023). However, progress is being made in the EAPP, with a shadow market run in 2023 and a day-ahead market set to launch in 2026.

The political economy issue has been addressed through the establishment of strong governance structures. These structures are designed to ensure competition in generation, competition on price, and openness to all participants (Barker et al., 1997). Governance in a pool is defined by the independence of the system operator, fair and non-discriminatory access to an efficient market, grid achieving required reliability levels, transparency in decision making, flexibility of rule changes in the pool and market within a reasonable time, and a minimised cost of governance.

The EAPP does not have autonomy in operation, owing to the disjointed cross-membership of COMESA and the EAPP by the countries of the pool. Not all EAPP members are COMESA¹⁵ members; thus, a regional regulator was established that reports directly to the council of ministers of the EAPP. This presents a challenge in decision-making for the pool, as ministerial meetings will always be required to pass resolutions of technical and political nature. A pool requires a regional body through which decisions can be made. Argues for a

¹⁵ COMESA – The Common Market for Eastern and Southern Africa is a regionaleconomic community in [Africa](#) with twenty-one member states stretching from [Tunisia](#) to [Eswatini](#).

focus on developing decision-making protocols that allow the pool to decide on technical and operational matters internally (Elabbas, 2023b).

The opening of the pool to IPPs¹⁶, as is the case in the SAPP and WAPP, could weaken the political influence of member countries in the pool by allowing the private sector to participate in decision-making. The WAPP has the private sector participating with more voting rights than the SAPP, where IPPs participate but have limited voting rights. However, this is related to the process by which these markets and the countries in the pools developed deregulation (Elabbas, 2024). Currently, the EAPP does not allow private sector participation.

Some researchers have argued for investment in decentralisation and bilateral arrangements (Hancock, 2024; Odetayo & Walsh, 2021). They add that African power pools, such as the EAPP, are motivated by development interests (donor governments and development banks), dominant African countries, and mining companies. This approach of investing in regional integration hampers the region's ability to improve energy security, standards of living, and achieve climate change goals (Hancock, 2024).

It is recommended to conduct research on proposing a system of operation of the EAPP that provides for the overarching interests of all the members and allows for the distribution of welfare to all countries. This future research would incorporate political considerations that are uniquely relevant to the countries of the EAPP.

¹⁶ Independent Power Producers

5.4.5. Research into the Project Finance Economics of Wholesale Markets

The key informant interviews revealed a misalignment between the simulation's system-level clearing price findings and the project finance perspective of generation investors. A minority of informants argued that wholesale market conditions would produce higher effective prices than bilateral contracting for new investors. In their view, this is because of the absence of long-term offtake certainty in the wholesale market. This raises the weighted average cost of capital and, thus, the minimum viable price required to finance a new project. This is distinct from the system marginal clearing price that the simulation measures. This study does not model the relationship between the two.

This gap has direct policy relevance for the EAPP. If wholesale market-clearing prices are insufficient to attract private investment in new generation at acceptable financing costs, the market will fail to achieve VRE expansion objectives. Research into the project finance economics of electricity market transitions in developing countries is required. This should examine the relationship between system-clearing price dynamics and the minimum viable contract price under different financing costs and risk scenarios. This would provide a more complete picture of the investment conditions required for EAPP wholesale.

This research area would also complement the generation expansion optimisation work proposed in Section 5.3.3 and be relevant to the design of CfD strike prices and capacity payment levels in the EAPP.

CHAPTER 5.5: CONCLUSIONS

5.5.1. Research Approach

This study adopted a mixed-methods sequential explanatory design. The study began with a quantitative agent-based simulation of the EAPP day-ahead wholesale electricity market and continued with qualitative key informant interviews. The qualitative process was essential for validating, contextualising, and extending the themes from the simulation findings. The explanatory sequential design was chosen because the EAPP wholesale market does not yet exist. This made empirical observation impossible, rendering simulation a practical means of generating system-level quantitative insights. The qualitative phase was then necessary to ground these insights in the operational and institutional context of the EAPP.

The quantitative instrument was the AMIRIS model (version 2.0.0-alpha.33), an open-source agent-based wholesale electricity market model developed and maintained by the German Aerospace Center (DLR). The model was adapted for the EAPP by replacing the German 2019 reference scenario with the generation, demand, and resource data of five EAPP countries. The modelled countries were Kenya, Uganda, Tanzania, Ethiopia, and Rwanda. Modelling was performed for the year 2025, with a validation scenario for 2023. This adaptation involved modifying the scenario and contract YAML files, inputting country-specific power plant data, and deriving hourly time-series for demand, solar, wind, hydropower, and bioenergy. National generation masterplans and publicly available international renewable energy resource databases were used. The model was verified against its own source code and externally validated by running a Kenyan 2023 scenario and comparing the output against statistics published by the regulator, the Energy and Public Utility Regulatory Authority (EPRA). The total dispatched energy deviated by 0.58% from the actual

figures, establishing the model's methodological credibility. Thus, the model was adapted for the EAPP simulation.

Five scenarios were run. The base case modelled the generation capacity confirmed as operational or under construction for 2025, totalling 19,575 MW. The high-VRE case modelled the full planned capacity from national generation expansion plans for 2025, totalling 26,121 MW. This was dominated by a large expansion of wind and solar in Ethiopia. Three sensitivity scenarios were performed. A medium-VRE scenario was constructed at the exact midpoint of the base and high VRE capacity additions (+2,773 MW above the base case). A geothermal must-run scenario that assigned priority dispatch to geothermal plants regardless of the market-clearing price under the high-VRE scenario configuration. Finally, an optimal-VRE capacity scenario that identified the level of additional VRE capacity at which the annual mean market price crosses zero. The three additional scenarios extended the research to cover areas of weakness in the high-VRE and base scenarios. Their incorporation reflected feedback from the key informants.

Qualitative validation was conducted through semi-structured interviews with 11 experienced sector practitioners. They came from regulators, utilities, generators, and the EAPP Secretariat, across Kenya, Uganda, Tanzania, and Ethiopia. The informants were presented with the simulation results and invited to assess the model's assumptions, findings, and implications for EAPP market design. Qualitative data were analysed through inductive thematic coding, producing eight themes that served both as a validation instrument and as a source of contextual findings on the EAPP.

5.5.2 Theoretical Framework

The study's theoretical framework draws on three bodies of literature that provide the conceptual basis for the research questions, design of the simulation, and interpretation of the findings. These are electricity market design theory, VRE integration theory, and political economy theory in power pools.

Electricity market design theory provides the foundation for competitive short-term markets (Kirschen & Strbac, 2018; Stoft, 2015). The theory holds that marginal cost-based clearing in a day-ahead market produces lower average electricity prices than bilateral contracting. Least-cost generation from in a pool is prioritised in dispatch. This results in price signals for investment. Bilateral contracts have inflexibility in pricing and contractual timing that does not enable short-term trading. The ‘missing money’ problem is the main design challenge in electricity markets. In an energy-only market, the merit order effect of zero-marginal-cost renewable generation depresses average prices to levels that cannot sustain investment in dispatchable capacity (W. W. Hogan, 2005, 2015; Stoft, 2015). Theory recommends capacity mechanisms and contracts for difference as solutions to this challenge.

Currently, electricity grids face pressure from increasing levels of VREs. The integration of VREs is the subject of VRE integration theory. This theory allows the interpretation of the merit order effect of VREs. VREs operate at zero marginal costs and lead to negative pricing in times of high supply and low grid demand. These negative prices not only cannibalise VRE revenue but also depress overall revenue for generators. A higher penetration of VREs also requires greater flexibility services and ancillary markets. The theory predicts declining average prices, increasing negative pricing, declining conventional plant utilisation, and deteriorating storage economics in an energy-only market. Contracts for

difference, vesting contracts, and ancillary service markets are the main regulatory instruments for managing these effects during the transition to high-VRE grids (Ason & Dal Poz, 2024; Brown & Reichenberg, 2021; Holttinen et al., 2012, 2021; Reichenberg et al., 2023; Sewalt & De Jong, 2003).

Power pools are cross-country organisations with interactions of different ideologies and leadership styles. Political economy theory frames the institutional and geopolitical constraints on the EAPP's development. The distributional consequences of regional integration must be factored into market design and operations. The tension between the gains of pooling power and national energy sovereignty is pertinent. The EAPP is particularly cited as having tensions between countries over generation projects. The case of Egypt and Ethiopia's disagreements over the Nile waters and the latter's construction of the GERD dam is highlighted. The low degree of autonomy of the EAPP technical decision-making is highlighted as a major drawback of the pool. Decision-making is often delayed to political meetings of ministers and not delegated to technocrats. The SAPP's approach is cited as a best-practice approach in the literature (Barnett, 2014; Elabbas, 2023a; Elabbas et al., 2023; Oseni & Pollitt, 2016; Prinsloo, 2019).

5.5.3 Conclusions by Research Question

RQ1: How is electricity traded globally and in Eastern Africa?

Electricity trade in the EAPP is currently conducted through long-term bilateral PPAs between utilities. There is no operational short-term market. The five sampled countries operate their electricity sectors at varying levels of unbundling. Uganda and Kenya are the most liberalised, while Ethiopia, Tanzania, and Rwanda have centralised structures. Cross-border trade is limited to a small number of bilateral arrangements, including the Kenya-Ethiopia take-or-pay PPA, the Kenya-Uganda power exchange, and shared hydroelectric facilities between Rwanda, Tanzania, and the DRC. This trade is currently constrained by limited interconnection capacity and the absence of a common market framework. The EAPP countries plan to establish further transmission interconnections.

The key informant interviews extended the literature by providing current intelligence on the development of EAPPs. The pool has established a regional regulator in Uganda, is developing market rules, has undertaken tests on trading, and has developed grid codes. An EAPP day-ahead market is targeted to be launched in 2026. The anticipated market structure will allow bilateral contracts to coexist with the day-ahead market. The short-term portion of the market is expected to grow progressively as legacy PPAs expire. This transitional pattern is consistent with the literature on developing-country electricity market reforms (Rudnick & Velasquez, 2018).

The informants acknowledged that the EAPP lags the SAPP, which already operates day-ahead and balancing markets. However, the EAPP's surplus generation capacity in several member states provides a more favourable starting condition for short-term trading than the

SAPP had at launch. The informants confirmed that the political governance structure of the EAPP is a binding institutional constraint on progress.

RQ2: How would a wholesale electricity market be affected by variable renewable energy?

The simulation produced a set of findings that were consistent across all five scenarios. In the base case, the annual mean market price of +67.5 EUR/MWh reflects a market with adequate average pricing. The inability to supply for 556 h per year (represented by achieving the 1500 EUR/MWh ceiling price) due to insufficient capacity is a point of concern. This was noted to occur during the evening peak. In the high-VRE case, additional capacity eliminates the supply shortfall. However, the average market-clearing price collapses to -295.6 EUR/MWh, with negative prices occurring in 77% of the hours. VRE supplied 85% and 99% of the awarded energy in the base and high-VRE cases, respectively. Conventional plant dispatch fell by 93%, and CO₂ emissions fell by 98% from 1.8 million to 37,000 metric tons.

The results and feedback from the qualitative process necessitated the execution of further sensitivity scenarios. The three additional scenarios run were medium-VRE, optimal-VRE, and a geothermal must-run scenario (extended from the high-VRE scenario). The medium-VRE scenario demonstrated that the price-penetration relationship is nonlinear. Adding the first 2,773 MW of capacity reduces the mean price by 151 EUR/MWh, whereas the second equivalent tranche reduces it by a further 212 EUR/MWh. The merit-order inflection point, where VRE begins to erode prices even during peak-demand hours, is reached between the base and medium-VRE levels. At that point, 41% of peak-demand hours return negative prices. The optimal-VRE scenario quantifies the market absorption capacity while retaining non-negative average pricing. The average market price crosses zero at $\alpha = 0.186$.

This meant that only 18.6% of the planned high-VRE capacity increment could be absorbed before the annual average price turned negative. This translated to an Ethiopian wind ceiling of 914 MW and a solar ceiling of 310 MW at 2025 demand levels. The geothermal must-run scenario confirmed that priority dispatch for geothermal is feasible without fundamentally distorting the merit order, although it further depresses the average market-clearing price. This provided a quantitative basis for the regulatory recommendation that follows.

Negative pricing findings require regulatory intervention to ensure investments in the EAPP. Wider electrification is still needed, and the region has available renewable energy resources. Negative prices provide disincentives for investment. This research recommends contracts for difference with a strike price based on the IRENA LCOE per technology, adjusted for regional financing costs. A floor price set at or near zero is recommended as a minimum market design feature.

It is acknowledged that a minimum price floor is an indirect subsidy to generation investors. This can, however, be justified on the grounds of market failure. The absence of long-term offtake certainty implies that the cost of capital for new generation projects in the EAPP is elevated. Market price signals alone are insufficient to encourage the private investment needed to expand VRE capacity. The IRENA LCOE ceiling on the strike price protects consumers from above-cost pricing and ensures that the subsidy element is bounded and transparent. However, this finding must be qualified by first ensuring that only an optimal level of increase in VRE on the EAPP should be considered to manage oversupply, which also leads to negative pricing.

Conventional generation assets that have already been built would also require better utilisation, even in high-VRE cases. These represent sunk costs, and their utilisation would

improve overall welfare. This is also the case for geothermal power plants, although renewable, which are priced out of the market by zero-marginal-cost VRE generation. Regulatory interventions would be required to ensure welfare, considering sunk costs.

RQ3: How accurate is the model for the EAPP?

The quantitative validation scenario against Kenyan 2023 grid statistics was run. It produced a 0.58% deviation in the total dispatched energy from EPRA actuals. This establishes the credibility of the model for the EAPP simulation. Qualitative validation through key informant interviews produced a positive assessment of the model. Five misalignments between the simulation and the operational realities of the EAPP were highlighted.

The most significant misalignment is the assumption of an infinite transmission capacity. The informants unanimously identified this result as optimistic in terms of supply security. In reality, the limited interconnection capacities of the EAPP would limit trade in generation and demand surpluses and deficits. The possibility of an infinite transfer capacity, as envisioned in this assumption, does not exist. This could lead to peak supply shortfalls.

Geothermal curtailment misalignment (4.44% utilisation in the high VRE case) was identified as being commercially and operationally unrealistic. This motivated the development of a geothermal must-run sensitivity scenario.

The simulation produced average negative prices for the high-VRE scenario (-295.6 EUR/MWh). The magnitude of negative pricing was attributed partly to the overestimated Ethiopian VRE capacity. The battery storage commercial loss was identified as understated by the exclusion of ancillary service revenue.

The investor pricing direction (a minority view that wholesale markets would produce higher, not lower, prices) arose as a distinction between system-clearing prices and project finance break-even prices. The simulation does not model project finance costs. These misalignments define the agenda for future methodological improvements. They define the boundaries within which the simulation's findings should be interpreted.

5.5.4 Study Limitations

This study was conducted within a set of assumptions and data constraints that define the scope of its findings. The most significant limitation is the assumption of an infinite transmission capacity between EAPP countries. This enabled AMIRIS to use the single-zone market model, but produced an optimistic supply security result. This does not reflect the actual interconnection infrastructure of the EAPP. As discussed in RQ3 in section 5.5.3., this is the assumption that most directly determines the headline supply security finding. Future modelling that incorporates transmission constraints should produce materially different results on peak price duration and load-shedding frequency.

The second limitation of the research is the use of national generation expansion plan figures for the high-VRE case. These figures were not adjusted for realistic deployment rates. The literature on VRE deployment in developing countries confirms that national expansion plans systematically overstate the pace of capacity addition (IRENA, 2023). This was also highlighted by the key informants. The Ethiopian 2025 wind and solar targets were highlighted as unrealistic. The optimal-VRE sensitivity scenario provided a partial remedy by identifying the market absorption capacity below which prices remain positive. However, this does not replace the need for a deployment-adjusted scenario that reflects what is likely to be installed rather than what is planned. This would, however, introduce subjective biases into the research.

A third limitation of the research is the exclusion of an ancillary services market. The simulation assesses battery storage economics and conventional plant revenues against energy-only revenues. This undervalues assets that provide frequency regulation, voltage support, and other system services. A complete assessment of the EAPP market requires a co-optimized energy and ancillary services model.

The modelling of hydropower as run-of-river plants, using a generic German time-series in the absence of EAPP-specific plant data, is a fourth limitation. This introduces inaccuracies, primarily in operational flexibility and seasonal dispatch patterns.

Finally, modelling the five EAPP countries as a single pricing zone is another limitation. This implies that the simulation cannot reflect congestion costs or the geographical distribution of pricing signals that would influence investment location decisions.

These limitations are acknowledged throughout the thesis, and each identifies a specific research agenda for future work. However, they do not negate the study's principal findings. They define the confidence interval within which the findings should be applied in research and policy contexts.

5.5.5 Contributions to Knowledge

This study makes three contributions to the academic literature on electricity markets, VRE integration, and power pool development in Sub-Saharan Africa.

The first contribution of this study is empirical. This study provides the first agent-based simulation of a day-ahead wholesale electricity market for the EAPP. It generates quantitative findings on electricity pricing, dispatch dynamics, CO₂ emissions, and battery storage economics under varying levels of VRE penetration. These findings are not available in the published literature. Prior research on the EAPP has been qualitative or descriptive in nature. Research has focused on documenting the institutional development of the pool and characterising its political economy (Elabbas, 2023a; Prinsloo, 2019). This study addresses this gap.

The simulation was validated against actual Kenyan grid data and extended using three sensitivity scenarios. These provide a more granular and policy-relevant picture of the price-penetration relationship. Expert validation was further applied to increase the credibility of the findings. The study contributed empirical findings that the EAPP can only sustain up to 18.6% of the planned high-VRE increment to ensure a positive mean price. In the research, specific capacity ceilings of 914 MW and 310 MW for Ethiopian wind and solar, respectively, were established at the 2025 demand level. This is a quantitative contribution with implications for EAPP generation expansion planning. No other prior research has established similar thresholds.

The second contribution is theoretical. This research identifies and develops a conceptual distinction largely absent from the existing VRE integration literature. This tension exists between variable and firm renewable generation in a merit-order wholesale market. The

VRE integration literature, dominated by European and North American research contexts, primarily frames the integration challenge as a tension between VREs and fossil fuel-based conventional generation. In the EAPP context, the tension exists between VRE technologies that bid at or near zero marginal cost and geothermal plants. Geothermal plants, while technically and environmentally renewable, carry high capital and variable costs. These make them commercially operate as baseload plants and financially vulnerable to curtailment due to abundant lower-cost VRE.

This framing of renewable-versus-renewable (wind and solar versus geothermal) is unique. The regulatory design challenge of protecting geothermal investments without distorting the competitive pricing mechanism extends VRE integration theory. This also applies to the specific conditions of Sub-Saharan African power pools. This presents an analytical contribution that neither the European literature on VRE integration nor the African power pool literature on market development covers. It has implications beyond the EAPP for other regions where geothermal, run-of-river hydro, and other firm renewables compete with variable renewables in wholesale markets.

The third contribution is methodological. The optimal VRE capacity scenario provides a replicable and transparent approach for identifying the VRE absorption capacity of an electricity market. The level at which additional capacity tips the annual mean price from positive to negative is determined through the parametric scaling of an agent-based simulation. The approach introduces a single scaling parameter (α) that represents the fraction of planned incremental VRE capacity added to the base case. This allows the price-penetration relationship to be traced continuously from the base to the high-VRE case. The zero-crossing point is then identified.

The methodology then considers technology-specific capacity ceilings. The merit-order price sensitivity of the model produces actionable capacity planning parameters that link simulation outputs to generation expansion decisions. This approach addresses a methodological gap identified in the VRE integration literature. There are no systematic methods for bridging the gap between national expansion plan targets and realistic deployment levels of VRE that maintain positive market price signals. This thinking is unique to markets such as the EAPP, which have resource abundance and low demand levels. It is essential to consider this to ensure the efficient use of scarce resources and retention of investments. This approach can be extended to other power pool simulation contexts beyond the EAPP.

5.5.6. Final Comments on the Study

This study confirms that a short-term wholesale electricity market in the EAPP would encourage the further development of renewable energy, reduce the average cost of electricity supply, and eliminate instances of peak supply shortfall. A short-term wholesale market would materially contribute to the region's CO₂ reduction and Sustainable Development Goal (SDG) 7 energy access objectives. These findings are grounded in simulation evidence, validated against expert practitioner knowledge, and situated within the relevant theoretical literature.

The conditions for realising these benefits include sufficient transmission interconnection capacity between countries and regulatory frameworks that protect VRE investors while maintaining competitive market dynamics. Priority dispatch arrangements for geothermal plants and an institutional governance structure that insulates the EAPP technical and commercial operations from political interference are underway. These are already work in progress.

It should be noted that bilateral contracts will not disappear with the introduction of a day-ahead market. Legacy PPAs will continue to dominate trade for an extended transitional period. The liquidity of the day-ahead market will be limited initially, as observed for the SAPP. Bilateral contracts will, however, gradually be complemented by short-term market volumes as contracts expire and new generation is developed on a merchant basis. This coexistence is the expected and well-documented pattern of electricity market transitions in developing countries. As the EAPP moves forward to introduce short-term trading, may the hope and dream of a better livelihood for the people of the region be the force that drives the integration of electricity markets.

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APPENDICES

APPENDIX 1 : DATA COLLECTION TOOLS

APPENDIX 1.1: INTERVIEW GUIDE

This document provides a semi-structured Key Informant Interview (KII) guide with which to interview managerial staff in the electricity sectors of Kenya, Uganda, Tanzania, Ethiopia and Rwanda. Before beginning the interview, consent must be sought from the respondents and all ethical principles applied.

Table 7-1

Interview guide of the research

Introduction (read aloud to respondent or paraphrased by interviewer)	I want to thank you for taking the time to take part in this interview. I understand that you have a busy schedule and will therefore try to finish within a short time. My name is <i>George Aluru</i>, a PhD student at UNICAF University in Zambia, currently conducting a study on the East African Electricity market under the topic “Investigating the use of short-term electricity trading to encourage variable renewable energy development in the eastern Africa electricity market”. The researcher has modelled the East African Electricity Market as a Short-term electricity market, made assumptions, and run simulations for trade. A summary of provisional results is provided with this questionnaire. The aim is to get your feedback as a key informant on the assumptions and findings of the research. The interview should take a maximum of 1 hour. The session were recorded to ensure all your comments are captured. I will also be taking notes during the session. All responses were kept

	confidential and anonymous. This means that I will ensure that any information we include in the report does not identify you as the respondent. The audio recordings were destroyed after transcribing. Remember, you do not have to talk about anything you do not want to, and you may end the interview at any time. Are there any questions about what I have just explained? Are you willing to participate in this interview?
	Sign consent form: [Y] [N] Date: _____
Demographic characteristics	1. Sex: ☐ Male ☐ Female 2. Designation : _____ Years of industry practice: _____
Questions on the Semi structured Interview Questionnaire	
	• Questions to be kept open-ended without leading • Probes were used when necessary: • <i>Would you give me an example?</i> • <i>Can you elaborate on that idea?</i> • <i>Would you explain that further?</i> <i>I'm not sure I understand what you are saying. Is there anything else you'd like to share about that?</i>
Wrap-up	Is there anything else that you would like to add or discuss here that you think would be relevant to the issue? Do you have any questions or concerns? If you would like to

	follow-up with anything, please do not hesitate to contact me at <u>+254725024070 and <i>galuru@gmail.com</i></u> Thank you very much for your time.

APPENDIX 1.2: SEMI-STRUCTURED INTERVIEW QUESTIONNAIRE

Part 1: Demographic Information

Informant Country: Ethiopia [] Kenya [] Uganda [] Tanzania [] Multiple []

Informant Role: Regulator [] Utility [] IPP [] Ministry [] Financier [] Other []

Informant Number: _____

Sex: Female ☐ Male ☐

Designation: _____

Years of Experience: _____

Part 2: Research Main Questions

1. How is electricity traded in your country?
2. Are you aware of the Eastern African Power Pool and what is your view on the pool?
3. Short-Term Electricity trading involves the transfer of electricity for a consideration over shorter contracting intervals typically over a day or hourly intervals. The research envisions the introduction of such a market in the Eastern African power pool.
 - a. What is your view on such a market for Eastern Africa?
 - b. What enabling factors are needed?
 - c. What do you see as major hindrances?
4. The countries of Eastern Africa are endowed with abundant renewable energy resources in wind, solar, hydro, and geothermal. While there is huge potential for development of power plants based on these resources there may not be in-country demand to uptake this supply. Do you agree with this reflection?
Would implementation of short-term trading in an interconnected pool allow for better balancing of regional demand and supply?
5. The power markets in Eastern Africa have generation from renewable energy sources at varied pricing levels. These are mainly based on bilateral contracting between the utility and Power Generators or between two utilities. Trade

between the countries is currently also based on long-term bilateral contracting between different utilities.

6. In your view, would a switch to short-term contracting affect the price of supply from renewable energy sources? If so, how? If not, why?
 7. Would the availability of a regional short-term market allow for the development of more variable renewable energy sources (Wind and Solar)?
 8. What are your views on the assumptions and results of the simulation?
 9. Do you have any other views on the topic?
 10. Do you have a question for the researcher?
-

APPENDIX 1.3: INFORMED CONSENT FORM



UU_IC - Version 2.1



Informed Consent Form

Part 1: Debriefing of Participants

Student's Name: George Aluru Otieno

Student's E-mail Address: galuru@gmail.com

Student ID #: R1807D5825968

Supervisor's Name: Prof. Jairo Montoya Torres

University Campus: Unicaf University Zambia (UUZ)

Program of Study: UUZ: PhD Doctorate of Philosophy

Research Project Title: Investigating the use of short-term electricity trading to encourage variable renewable energy development in the Eastern African electricity market

Date: 21-Nov-2022

Provide a short description (purpose, aim and significance) of the research project, and explain why and how you have chosen this person to participate in this research (maximum 150 words).

The research focuses on the possibility of use of a short-term electricity market to encourage the further development of variable renewable energy projects in Eastern Africa. Special focus being on Kenya, Tanzania, Uganda and Ethiopia. The research will model a day-ahead market for the eastern African countries based on planned interconnection capacity and current generation. The aim is to investigate the potential of on-boarding more variable renewable sources given the ability to trade between these countries. The findings of this research and simulation will then be presented for a face-to-face discussion with key informants such as yourself to validate and extend the findings.

As a person with a particular knowledge in the electricity market in your country you have been chosen as a Key-Informant to help validate and enrich the research. An interview guide containing the relevant questions and a summary of findings from the simulation will be provided for your review before the interview. I kindly request your participation.

The above named Student is committed in ensuring participant's voluntarily participation in the research project and guaranteeing there are no potential risks and/or harms to the participants.

Participants have the right to withdraw at any stage (prior or post the completion) of the research without any consequences and without providing any explanation. In these cases, data collected will be deleted.

All data and information collected will be coded and will not be accessible to anyone outside this research. Data described and included in dissemination activities will only refer to coded information ensuring beyond the bounds of possibility participant identification.

I, George Aluru Otieno, ensure that all information stated above is true and that all conditions have been met.

Student's Signature: G.A.O



Informed Consent Form

Part 2: Certificate of Consent

This section is mandatory and should to be signed by the participant(s)

Student's Name: George Aluru Otieno

Student's E-mail Address: galuru@gmail.com

Student ID #: R1807D5825968

Supervisor's Name: Prof. Jairo Montoya Torres

University Campus: Unicaf University Zambia (UUZ)

Program of Study: UUZ: PhD Doctorate of Philosophy

Research Project Title: Investigating the use of short-term electricity trading to encourage variable renewable energy development in the Eastern African electricity market

I have read the foregoing information about this study, or it has been read to me. I have had the opportunity to ask questions and discuss about it. I have received satisfactory answers to all my questions and I have received enough information about this study. I understand that I am free to withdraw from this study at any time without giving a reason for withdrawing and without negative consequences. I consent to the use of multimedia (e.g. audio recordings, video recordings) for the purposes of my participation to this study. I understand that my data will remain anonymous and confidential, unless stated otherwise. I consent voluntarily to be a participant in this study.

Participant's Print name:

Participant's Signature: _____

Date:

If the Participant is illiterate:

I have witnessed the accurate reading of the consent form to the potential participant, and the individual has had an opportunity to ask questions. I confirm that the aforementioned individual has given consent freely.

Witness's Print name:

Witness's Signature: _____

Date:

APPENDIX 1.4: SAMPLE GATE KEEPER LETTER



UU_GL - Version 2.0



Gatekeeper letter

Address: ERA, Kampala, Uganda

Date: 02-Feb-2023

Subject: Request for Information Uganda Grid

I am a doctoral student at Unicaf University Zambia.

As part of my degree I am carrying out a study on Investigating the use of short-term electricity trading to encourage variable renewable energy development in the Eastern African electricity market.

I am writing to inquire whether you would be interested in/willing to share information on the electricity market in Uganda that is useful in the undertaking of this research.

Subject to approval by UNICAF Research Ethics Committee (UREC) this study will be using a simulation program which will rely on the information that is being requested of you. The research will then later involve face-to-face (Physical or Virtual) interviews to validate the simulation findings.

The study is undertaken under the supervision of Prof. Jairo Montoya Torres of UNICAF University. It will be looking into the benefits of having a Short-Term electricity market in Eastern Africa, for the penetration of variable renewable energy sources.

I would kindly request for information regarding

- The load/demand profile for the Ugandan Grid for both Weekdays and Weekends
- The Economic Merit order of dispatch or similar for the Ugandan Grid and tariff cost of generation assets
- Nature and Capacity of existing and planned regional inter-connectors

I assure you of the confidentiality of all information provided for the purpose of this research.

Thank you in advance for your time and for your consideration of this project. Kindly please let me know if you require any further information or need any further clarifications.

Yours Sincerely,

George Aluru Otieno

Student's Name: George Aluru Otieno

Student's E-mail: galuru@gmail.com

Student's Address and Telephone: Nairobi. +254 714 746 590

Supervisor's Title and Name: Prof. Jairo Montoya Torres

Supervisor's Position:

Supervisor's E-mail: j.montoya@unicaf.org

APPENDIX 2.1: KEY INFORMANT PRESENTATION

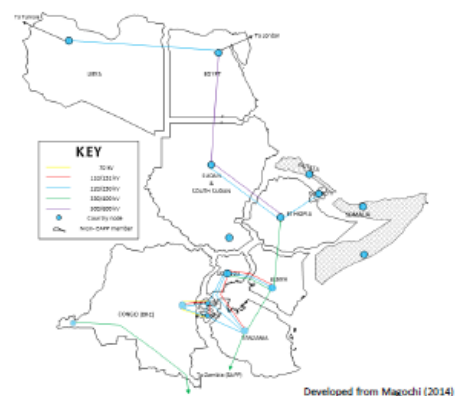
INVESTIGATING THE USE OF SHORT-TERM ELECTRICITY TRADING TO ENCOURAGE VARIABLE
RENEWABLE ENERGY DEVELOPMENT IN THE EASTERN AFRICAN ELECTRICITY MARKET

NAME: GEORGE ALURU OTIENO
INSTITUTION: UNICAF UNIVERSITY ZAMBIA
PROGRAM OF STUDY: PHD
SUPERVISOR: PROF. JAIRO MONTOYA TORRES



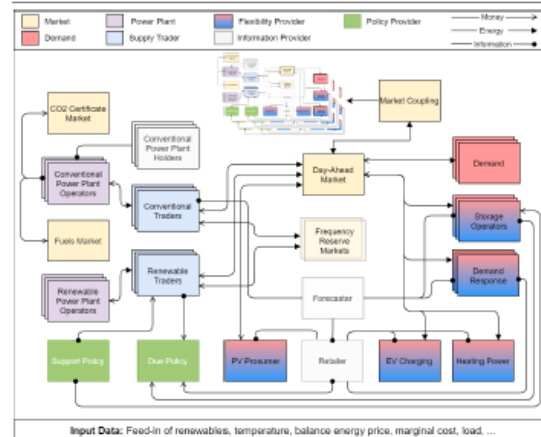
Introduction

- A simulation of the EAPP wholesale market was undertaken focusing on KE, TZ, UG, ET and RW
- The simulation was in response to the research questions
 - I. How is electricity traded globally, and in Eastern Africa? – Literature review and Key Informant Interviews
 - I. How is electricity traded globally?
 - II. How is electricity traded in Eastern Africa?
 - II. How would a wholesale electricity market in Eastern Africa be affected by introduction of more varying renewable energy? – Simulation
 - III. How accurate is the adapted model and simulation findings for the Eastern Africa Power Pool? – Key Informant Interview



25/11/2024

AMIRIS Model



- The Agent-based Market model for the Investigation of Renewable and Integrated energy Systems (AMIRIS) is an open agent-based electricity market model developed by the German Aerospace Agency (DLR)
- Aims at enabling scientists to dissect the complex questions arising with respect to future energy markets, their market design, and energy-related policy instruments

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Model Assumptions

Key Assumptions

- The modelling considers infinite transmission capacity
- The EAPP is modelled as a single zone day-ahead, hourly time-step market
- Dispatch according to European Electricity market rules
- Hydro plants modelled as VRE without dam storage
- Geothermal modelled as conventional plant with zero emissions
- The two scenarios have a 6.5GW difference in installed capacity in 2025
- High RE Scenario assumes
 - Significant build of Wind and Solar in Ethiopia
 - Battery storage in Kenya
 - Geothermal in Tanzania and Ethiopia

Base 2025

Hydro Power Plant	Power plant Code	Installed Power (MW)
Uganda	10	1,757.10
Kenya	11	858.01
Tanzania	12	3,770.00
Ethiopia	13	6,430.00
Rwanda	14	100.00
Thermal Power Plant (NRC)	20	100.00
Kenya	21	586.52
Rwanda	24	149.81
Thermal Power Plant (LNG)	32	962.00
Tanzania	34	30.00
Geothermal Power Plant	41	1,025.20
Tanzania	42	-
Ethiopia	43	-
Bioenergy Power Plant	50	17.00
Uganda	51	70.44
Ethiopia	52	80.00
Rwanda -Heat	54	50.00
Storage (Battery) Plant	61	-
Kenya	62	150.00
Uganda	63	251.75
Tanzania	64	-
Ethiopia	65	-
Rwanda	66	112.00
Wind Capacity	70	-
Kenya	71	405.50
Tanzania	72	314.00
Ethiopia	73	314.00
Total 2025 Capacity (Planned and Existing)		19,575.00

High Renewable Energy 2025

Hydro Power Plant	Power plant Code	Installed Power (MW)
Uganda	10	1,757.10
Kenya	11	858.01
Tanzania	12	3,770.00
Ethiopia	13	6,430.00
Rwanda	14	100.00
Thermal Power Plant (NRC)	20	100.00
Kenya	21	586.52
Rwanda	24	149.81
Thermal Power Plant (LNG)	32	1,262.20
Tanzania	34	30.00
Geothermal Power Plant	41	1,025.20
Tanzania	42	95.00
Ethiopia	43	207.50
Bioenergy Power Plant	50	17.00
Uganda	51	70.44
Ethiopia	52	134.00
Rwanda -Heat	54	50.00
Storage (Battery) Plant	61	250.00
Kenya	62	750.00
Uganda	63	251.75
Tanzania	64	3,675.00
Ethiopia	65	1,120.00
Wind Capacity	70	20.00
Kenya	71	405.50
Tanzania	72	314.00
Ethiopia	73	314.00
Total 2025 Capacity (Planned and Existing)		26,120.99

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Results – Model Validation using Kenya 2023

SIMULATION RESULTS FOR 2023

Metric	Value
Total Energy (GWh)	13,212.151
Dispatch System Cost (EUR)	740,537,551
Average Generation Cost (EUR/MWH)	167 (56.05)

EPRA/ KPLC STATISTICS 2023

Metric	Value
Total Energy (GWh)	13,289.63
Dispatch System Cost (EUR)	971,899,900
Average Generation Cost (EUR/MWH)	73.13

- The **total generated energy is similar in the simulation as in the official statistics**. The simulation result is within 0.583% of the reported results. The deviation can be attributed to lack of factoring imports and differences from actual dispatch in the simulation.
- The average price of generation is 28% higher in the simulation accounting for cost of under and over supply.
- The average dispatch cost per unit is however 23.35 % lower than the actuals

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DS 3

5

Results – Model Validation using Kenya 2023

SIMULATION RESULTS 2023

	Energy (GWH)
Geothermal	6,787
Hydro	2,976
Wind	2,357
Thermal	688
Net Imports	-
Others	404
Total	13,212

EPRA/KPLC STATISTICS 2023

	Energy (GWH)
Geothermal	6035
Hydro	2569
Wind	2202
Thermal	1396
Net Imports	644
Others	444
Total	13,290

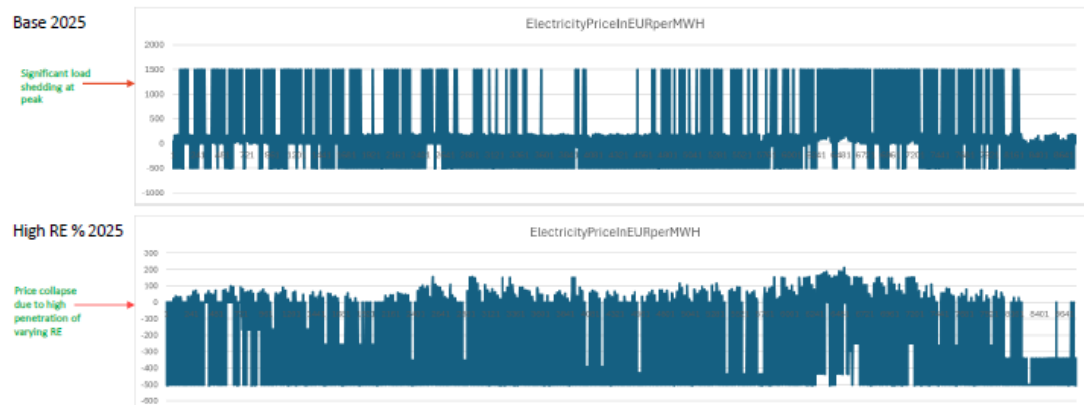
- The simulated energy by technology is similar to the actual data with significant deviations in Hydro (+16%), Thermal (-51%) and geothermal (+12%). This is reflective of the drought in 2023 that saw less hydro and more thermal dispatched.
- The simulation did not consider imports.
- Wind and Others (solar and Biomass) are within 10% of actuals
- 2023 statistics are also the twelve-month period between July 22 and June 23, not Jan-Dec 2023

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Results: Electricity Price



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Results: Electricity Price

	2025 Base Case	2025 High Renewable Case
Average Electricity Price (EUR/MWH)	68	-295.57
Total Energy (MWH)	61,499,095	62,569,826
Dispatch System Cost (EUR)	3,198,766,839	2,779,417,034
Per Unit Dispatch System Cost (EUR/MWH)	52.01	44.42
Instances of under supply at peak (Hrs)	556	0
Instances of (-500 condition) Market max negative prices (Hrs)	1,889	2451
Instances of negative market price (Hrs)	1979	6792

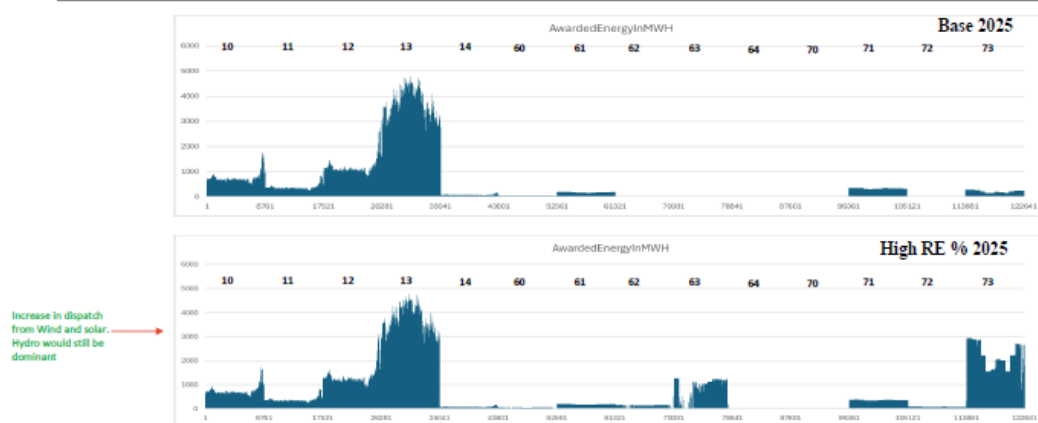
- In a High RE scenario
 - The average price of energy would collapse (-ve prices for 77.5% of the time) while the per unit dispatch cost would reduce by 14.56%
 - System cost will reduce significantly
 - Peak demand will be well catered for. No curtailing of load at peak
 - Instances of negative market prices would increase

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Results: Awarded Energy to Varying Renewables operators



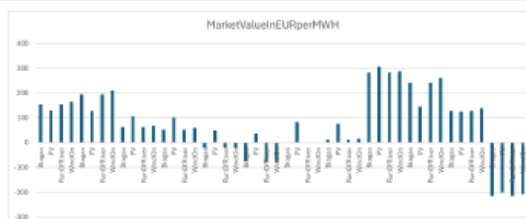
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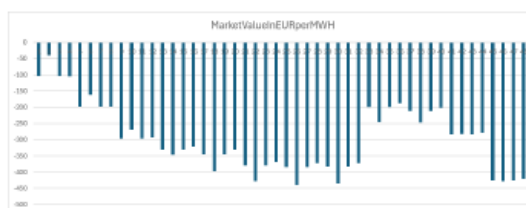
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Results: Support Policy Market Value

Base 2025



High RE % 2025



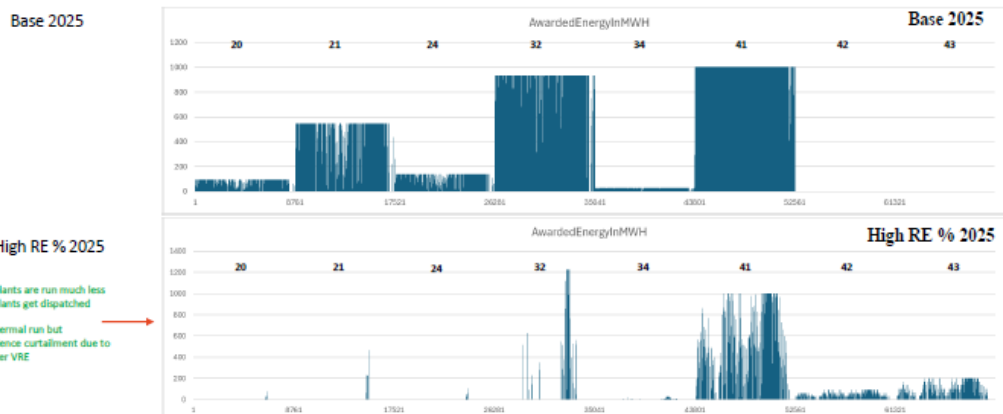
For a sampling of the year the value of incentives for RE collapses as a high penetration of RE pushes prices below zero

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Results: Conventional Plant Awarded energy

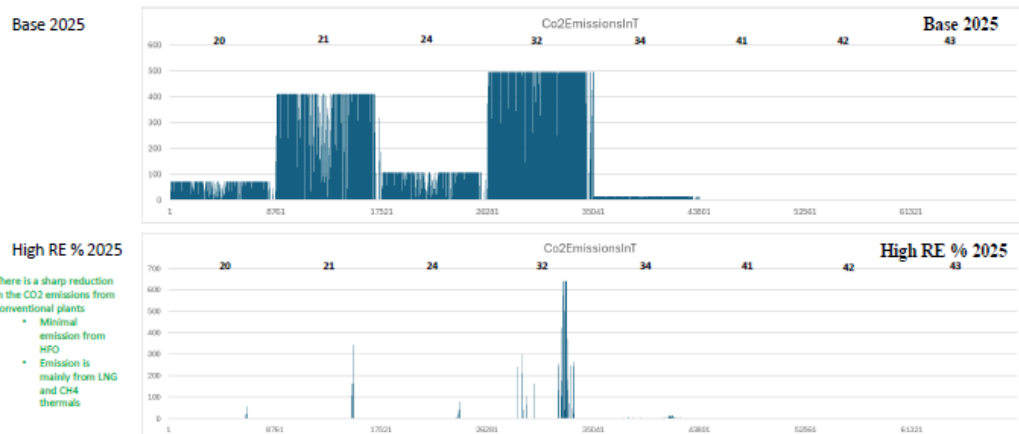


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Results: Conventional Plant CO₂ Emissions

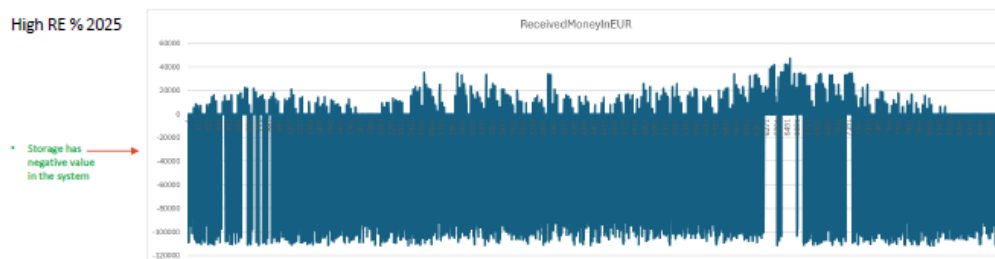


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Results: Storage Plant Revenue in High RE



- In a market scenario the battery storage facility will run at a significant loss

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DS 3

13



Feedback Session

- Feedback from Key Informant

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DS 3

14

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APPENDIX 2.2: KEY INFORMANT INTERVIEW TRANSCRIPTS SAMPLE

Key informant 001

Interview with Key informant 001

Age: XX

Years of Experience: 31

Sex: Male

Duty Station: Nairobi, Kenya

Organisation: XXX

Interview started with a presentation of the results followed by a series of questions as guided by the questionnaire and summarised below.

The questions

Researcher: How is the electricity trading in your country? I will just ignore because we both know. Just through the PPA, and between the countries. But there are a lot of agreements

Informant 001: Exactly

Researcher: Maybe also just talk about the second one . What is your opinion on the pool?

Informant 001: Okay, to me the pool, I think as East Africa power pool, I think we have not been making the correct steps towards achieving the power pool. I think we have been really holding onto our own cocoons. Like countries I think we want to maybe struggle just to make up our country power deficits reduce without seeing the benefits of going to the Eastern Africa power pool. But if we can learn from the what the South African power pool has done and also the west African power pool is now being materialized

I think as this East Africa we need to develop that because Ethiopia is doing a lot of hydro and Kenya is doing a lot of Geothermal. We see we have a lot of varied resources in the region. Tanzania was trying to expand the natural gas generation and if we could now go into the power pool then they can't do it. There is no need to try to do the natural gas power plant in Kenya. Because Tanzania was doing that then you can now trade within the pool.

I think that is the best so that we now have economic value the various resources we have is needed because there is no need to do very small plants. Because now we see the plant cost become higher isn't it

Researcher: Exactly

Informant 001: But if we are now doing like Ethiopia doing the big hydro powerplant in the long run the plant cost comes down, isn't it? We have developed a wide market so now we are building bigger plants, isn't it?

Then we find the bigger the plant is the per unit cost comes down. That's what we need to do. I believe that is what the EAPP needs to do. And also, in the connectivity makes our system more robust isn't it?

From a power system point of view because me am a XXX engineer, you go to Europe and the Europe systems are more robust, isn't it? And they can take a lot of shocks without system collapses because they are interconnected

So some of these are some of the benefits that they probably bring to us. But I think ours has been controlled so much by politics. And the EAPP structure, isn't it? Or the council of ministers they now go to the summit and all that isn't it?

Some of the decisions made at the technical level, when they go up there is water down. I think we need to find our way a way to improve the decision making. Like you go to the ministers now those are politicians; you go to the summit there are now purely politicians and that they have got a lot of geopolitics and all that isn't it?

Researcher: Yes

Informant 001: But I think I don't know if they delink the power pool from politics. I don't know what can be done. Maybe that's one of the things you must find out how the SAPP has done it. So that they have delinked from the geopolitics, isn't it?

And they are looking at maybe something which is beneficial to the whole region

Researcher: The third question. I just described what short-term electricity trading is. It involves the transfer of electricity for consideration of a short-term contracting interval. Typically, they are a day or an hour and we envision such a market for the African power pool

What is your view on that? What do you think we need to enable this? What are the main hindrances you foresee?

Informant 001: Thank you. That's a very important question. The first things like now we see that's why Kenya we did the power market study. I think there's no way you can talk about and EAPP market if you don't have the power market within our own countries. I think this is the best thing that other countries should have done. Kenya can have an individual power market study to find out how we can operation the power market within Kenya.

One of the things that we do a study, which should inform us the correct regulations for what kind of market we want and what is applicable. Some things we may want but also what's applicable in our society. Like you even us we have seen some of these bilateral and long-term PPAs will control the market for some time, isn't it?

Researcher: Exactly

Informant 001: But what window do we have to bring out the day ahead and hourly market so that we have a hybrid that will run before we have a pure market structure. So the best thing we will help and support this is regulations. First of all we will do a study which will now give some information to make the right decisions and from the study now we will do regulations.

And this regulation now is what now the legal framework that is needed. People will not come like now even within a football match If there are no rules, then the referee will have a very difficult work to do, isn't it?

Researcher: Yes, yes

Informant 001: Having the legal framework that comes with the proper regulations is really key for the markets . At that, we should start from the country markets, then now we are escalating now the regional level.

Even as we are discussing here, Do we bring on the power plants just to just trade in the Kenyan market or start trading at the regional market. Those are the things we need to look at.

Researcher: And what do you feel as a main requirement? or let me just I think I can get the answer from what you just answered. The main thing that I am saying is regulation and how to start it also.

Informant 001: How to start it and make the right decision of having the right kind of market.

Researcher: Okay, so let's move to the next one. The region is endowed with renewable energy wind, solar, hydro and geothermal. There is a potential to develop power plants based on these resources that may not be in country. I think you already agreed with that

Would the implementation of short-term trading in this interconnected pool allow for better balancing of regional demand and supply which I think you have already answered in one of your answers

Informant 001: Check at how we are working with Uganda. Like I already know it is a kind of energy exchange program. We don't have good hydro resources, and they can develop bigger hydro projects. We know about the deficit we get from Uganda. When they have problems on of supply then Kenya can also give them.

And the only thing is that we are giving them through kind of long-term agreements. But if we could be now doing a market, instead of venting geothermal. Yes, you can do this a little bit. Yes, that means that we will give the power at concessional rates, instead of venting, isn't it? And then now we will be fighting climate change. Even now that we can tell you (power plant operators) that we are going to please switch off all your thermal power plants will give you at this rate. You see that will help us as a region look at the problem holistically.

Why run expensive thermal powerplants in Uganda also when you can access cheaper geothermal from Kenya. Kenya would be able to give them the cheaper power from geothermal. While we are now venting this steam, that will now come in. Uganda can find it very much attractive to switch off the thermal power plants as prices would have reduced from regional suppliers.

Likewise, you know that we are now finishing the line to Tanzania. So I think that is one of the ways we should now look at how we can progressively introduce those their days heads and also projections. But you see also having that interconnection, and even with our Scada system, we also would end up having that market operator. Who is this, who is going to do the

declaration of capacity? IF we have a central organisation doing the declaration then that will help us do the trading.

Researcher: Let me just ask, there is something that you are calling on the regulations, the regional coordination centre. Is this like a centre of the EAPP that is based in one of the countries?

Informant 001: By the time now we go to the regional market, then you must have a coordination centre. Both for the planning and even for dispatching and also for the trading?

Researcher: I think question five also has been answered by us, so it's right now we are doing bilateral contracting. If we switch to short time contracting, will this affect the price of supply? And if so, how and if not why?

Informant 001: Yes, and we are sure that the bilateral, even while the time we do the power pool the hybrid will be with us for a long time before some of those PPAs will terminate. Terminating them will have a lot of negative economic benefits. Yes, so I think you will allow them to run for their life before the market is operated in full.

Researcher: On the sixth question, I think also this is partially answered, does the availability of the short time market allow for more varying renewable energy sources to be developed, especially wind and solar?

Informant 001: Yes, because they have only problem with now, the way we are doing our power of planning. We are planning on some kind of restricted load, this is the demand. Now we are matching the local demand and the local supply isn't it? But if we are going for a power market, then we can now bring power plants which can just trade in the market and they are not now following the strict planning based on the balancing of the supply and demand, isn't it?

The only challenge I am seeing there is the risks, these power plants will be seeing before they come on, isn't it? If the market is not mature enough, can you bring a power plant, can you bring a solar power plant of 40MW, just to be like the trading in a market, which is not really mature, isn't it? I think that's enough for them to generate enough revenues to pay money investments, is that my main worry?

Researcher: I agree that that is a challenge, I am seeing the South African power pool, they have like these aggregators, there's like a third party that comes and sits in between the demand and the supply, guarantees of take and also guarantees supply to the consumers. So perhaps when the market is set up, there can be people who can come and sit in the middle with the business model, they are kind of an off taker.

Informant 001: Yeah, because like now we see the current system here, we know that all even the wind and the solar, they are guaranteed some kind of uptake that's why you have the deemed generation, isn't it?

And that's what makes the investors be comfortable, if they put the investment, at least they get some money to pay the investment, isn't it? But if I am putting a power plant, just to trade the

market and I'm not sure how the market will behave, isn't it? I think those are the things we need to see how to derisk that kind of market, isn't it? And make sure that the investments can be comfortably paid for, but I think no investor will come and put a power plant, if they are not sure. And they know that there may be their equity or their debt and they put it in an investment, if they are not sure, there's that payment for.

Researcher: Yes, agreed. Then, the next question would have been the views on the assumptions and results of the simulation, but I think as I was doing the presentation.

Informant 001: I think I've discussed with you,

Researcher: do you have any other views on the topic or any question that you would want to ask me?

Informant 001: Okay, I wish all the best, maybe just let's see what kind of parameters you can bring to make the model become as close to reality as possible, like some of these issues which are not very difficult to bring in

Where I saw some of these parities, like now between the thermals, remember we have some issues with the thermals, isn't it?

Yeah, then we can we check, maybe the low hydrology, what can we use to do in the model to make it close to reality, isn't it?

And the geothermal, do you remember the venting of the steam? So you can see maybe how much it is to get as close to reality as possible

And then the using of data, like the data from Ethiopia which is so much exaggerated could also be giving the unrealistic picture and could be given a wrong picture, isn't it? So, if we can make it as close to reality as possible, then that will be better for us.

Researcher: Now the challenge now with the data from Ethiopia is, you know there is no basis for me to say now this is to be the high-renewable case, I can only go with what they have in the Least cost power development plan, which is at the moment is completely unrealistic

Informant 001: That's why I told you, that comment here. I remember when we also started doing our least cost development plan, we faced the same scenario where we are having a very unrealistic kind of projections

And that's why we adjusted and now we do them in three scenarios, isn't it? Optimistic, the realistic, and pessimistic. Sometimes you find that we tend towards the pessimistic, and that's what it says but then it's informed by our experience, and even in Tanzania, I have seen their planning is a bit off the cuff.

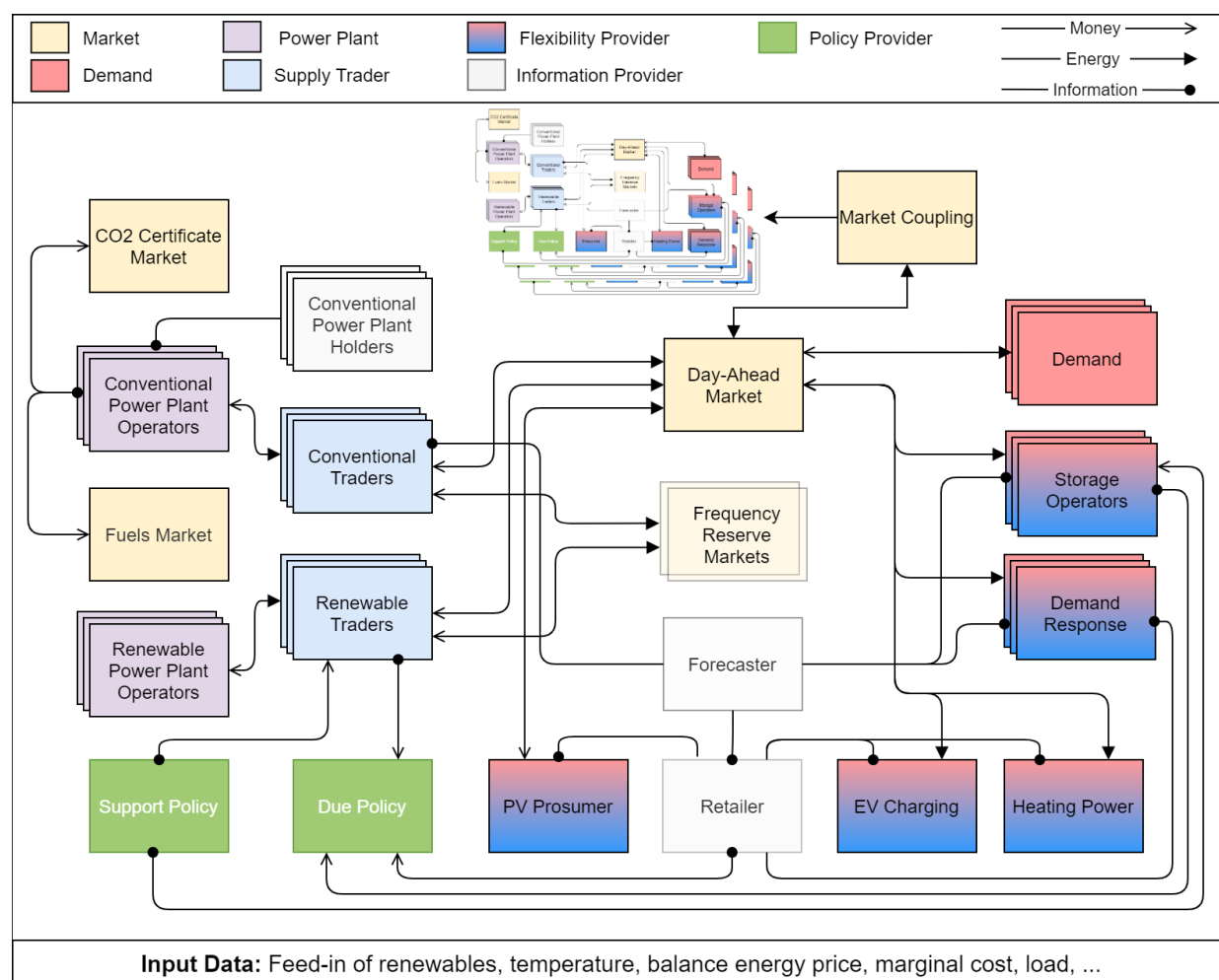
Researcher: Yeah, I mean for Ethiopia, the plan I think came out in 2021, so I mean for them to be very, very off in 2025 is also suspect. The Kenyan plan gets off like from 2030 something, from today in 2034, 35, that's where now we are off.

Informant 001: For Kenya we've used the real scenario; we are almost on the spot. Especially for tracking demand. Yeah, I think we have built capacity and that's one of the things, some of those who have been the system, long, know most of the inside workings. Yeah, that's it, thank you so much.

Researcher: Let me release you now to go back to your meeting, thank you so much.

Informant 001: God bless, and I wish you all the best.

APPENDIX 3: AMIRIS MODEL DESCRIPTION



APPENDIX 4: RESEARCH ETHICS APPROVAL FORM AND DECISION FORM



REAF_DS - Version 3.1 AP



UNICAF UNIVERSITY RESEARCH ETHICS APPLICATION FORM DOCTORAL STUDIES		UREC USE ONLY: Application No: _____ Date Received: _____
Student's Name:	George Aluru Otieno	
Student's E-mail Address:	galuru@gmail.com	
Student's ID #:	R1807D5825968	
Supervisor's Name:	Dr Jairo Montoya-Torres	
University Campus:	Unicaf University Zambia (UUZ) ▼	
Program of Study:	UUZ: PhD Doctorate of Philosophy ▼	
Research Project Title:	Investigating the use of short-term electricity trading to encourage variable renewable energy development in the Eastern African electricity market	

1. Please state the timelines involved in the proposed research project:

Estimated Start Date: 24-Oct-2022

Estimated End Date: 30-Sep-2023

2. External Research Funding (if applicable):

2.a. Do you have any external funding for your research?

☐ YES

☒ NO

If YES, please answer questions 2b and 2c.

2.b. List any external (third party) sources of funding you plan to utilise for your project. You need to include full details on the source of funds (e.g. state, private or individual sponsor), any prior / existing or future relationships between the funding body / sponsor and any of the principal investigator(s) or co-investigator(s) or student researcher(s), status and timeline of the application and any conditions attached.

2.c. If there are any perceived ethical issues or potential conflicts of interest arising from applying for and receiving external funding for the proposed research then these need to be fully disclosed below and also further elaborated on, in the relevant sections on ethical considerations later on in this form.

3. The research project

3.a. Project Summary:

In this section fully describe the purpose and underlying rationale for the proposed research project. Ensure that you pose the research questions to be examined, state the hypotheses, and discuss the expected results of your research and their potential.

It is important in your description to use plain language so it can be understood by all members of the UREC, especially those who are not necessarily experts in the particular discipline. To that effect ensure that you fully explain / define any technical terms or discipline-specific terminology (use the space provided in the box).

This research assesses the viability of the introduction of a short-term electricity market in the Eastern Africa. The continued build-up of generation capacity in Eastern Africa and the lagging demand growth will result in countries having excess power. Countries will need to trade this power with their neighbors on short-notice given fluctuations in weather and outages of generation facilities. Current arrangements for electricity trade in the region involve long-term or emergency bilateral contracts that do not allow for flexibility to trade over one day time-frames. Countries will likely be stuck with excess generation capabilities that they cannot commercialize in the short term, and ultimately experience high electricity prices due to the fixed costs on the installed idle generation capacity. The research investigates the use of short-term (day in advance) trading of electricity.

The research questions considered for this study are;

1. How is electricity traded globally, and in East Africa? This will explore bilateral contracts, intra-day, real-time, and day-ahead trading.
2. How would the trading of Electricity be affected by the introduction of short-term trading? This would involve modeling to look into a). How does the implementation of short-term trading of electricity affect the balancing of demand and supply in a power pool? b). How is the pricing of variable renewable energy supply affected by switching from bilateral contracts to a short-term traded market? c). How does the introduction of short-term trading in power pools affect the development of variable renewable energy projects? d). How do market-related factors affect the expansion of variable renewable energy projects in power pools?
3. The final research question focuses on validation of the model asking, how accurate is the developed model for short-term trading? This will also involve key stakeholder engagements.

With the successful undertaking of this research, it is envisioned that there will be proof that short-term trading can work within the Eastern African power pool and that it can be used to successfully balance demand and supply and reduce costs. Short-term trading would also allow for further development of renewable energy sources that can then be traded at a regional level.

3.b. Significance of the Proposed Research Study and Potential Benefits:

Outline the potential significance and/or benefits of the research (use the space provided in the box).

This research is significant as it will shed light onto the possibility of using short-term trading to solve the current mismatch of supply and demand in Eastern Africa. Short-term trading of electricity is anticipated to allow for efficiency in the deployment of available renewable generation capacity to meet short-term needs. This research will progress the activities envisioned in the East African Power Pool by providing a model and analysis for short-term balancing of demand and supply, possible reduction of costs and encouragement of variable renewable energy penetration. This research will add to the body of work on integration of variable renewable energy into our increasingly changing electric supply systems. The recent global boom in development of wind and solar power projects and the ongoing downscaling of conventional power plants has led to increased interest in enabling the grid and its associated market to take up more variable renewable energy. The research will also add to the general body of work in the modeling of deregulated electricity markets by adding an East African perspective.

4. Project execution:

4.a. The following study is an:

- ☐ experimental study (primary research)
- ☐ desktop study (secondary research)
- ☐ desktop study using existing databases involving information of human/animal subjects
- ☒ Other

If you have chosen 'Other' please Explain:

Experimentation through modeling and simulation incorporating key-informant interviews to validate and extend findings of the research.

4.b. Methods. The following study will involve the use of:

Method	Materials / Tools
Qualitative:	☒ Face to Face Interviews ☐ Phone Interviews ☐ Face to Face Focus Groups ☐ Online Focus Groups ☐ Other *
Quantitative:	☒ Face to Face Questionnaires ☐ Online Questionnaires ☐ Experiments ☐ Tests ☒ Other *

*If you have chosen 'Other' please Explain:

The research will include the use of Software simulation tool developed for the East African Power Market.

5. Participants:

5 a. Does the Project involve the recruitment and participation of additional persons other than the researcher(s) themselves?

- ☒ YES If YES, please complete all following sections.
☐ NO If NO, please directly proceed to Question [7](#).

5 b. Relevant Details of the Participants of the Proposed Research

State the number of participants you plan to recruit, and explain in the box below how the total number was calculated.

Number of participants

The number is calculated based on the electricity sector participants in the four electricity markets of Kenya, Uganda, Tanzania and Ethiopia. These markets have private power producers, as well as state backed generation, distribution and regulatory bodies. A pool of 500 management level staffs (125 per country) is anticipated from which at least 20 key informants (5 per country) would be identified for the validation of the model results.

Describe important characteristics such as: demographics (e.g. age, gender, location, affiliation, level of fitness, intellectual ability etc). It is also important that you specify any inclusion and exclusion criteria that will be applied (e.g. eligibility criteria for participants).

Age range From To

Gender ☒ Female
☒ Male

Eligibility Criteria:

- Inclusion criteria
- Exclusion criteria

Disabilities

Other relevant information (use the space provided in the box):

5 c. Participation & Research setting:

Clearly describe which group of participants is completing/participating in the material(s)/ tool(s) described in 5b above (use the space provided in the box).

The participants in the key-informant interviews are persons of knowledge in the power sectors of Kenya, Uganda, Tanzania and Ethiopia. They will be management level employees of regulators, generators, transmission and distribution companies in the private and public sector. They will be persons deemed knowledgeable in grid and power markets in their respective countries and with a regional outlook. All sampled participants will be interviewed face-to-face in person or virtually via video conference depending on their preference and availability.

5 d. Recruitment Process for Human Research Participants:

Clearly describe how the potential participants will be identified, approached and recruited (use the space provided in the box).

Semi-structured face-to-face or video conference (zoom) meetings will be used to interview key stakeholders in the electricity markets of the East African region. These will include knowledgeable private and public participants in the various markets. The sampling of the views of stakeholders and data will follow purposive sampling to ensure that the most experienced and relevant respondents are interviewed. Participants will be identified from regional regulators, private power companies and power utilities. They will be called and emailed with a request for consent for an interview with the topics and University research approval documents sent in advance. Statistical sampling will be used in the running of simulations in the developed model.

5 e. Research Participants Informed Consent.

Select below which categories of participants will participate in the study. Complete the relevant Informed Consent form and submit it along with the REAF form.

Yes	No	Categories of participants	Form to be completed
☒	☐	Typically Developing population(s) above the maturity age *	Informed Consent Form
☐	☒	Typically Developing population(s) under the maturity age *	Guardian Informed Consent Form

* Maturity age is defined by national regulations in laws of the country in which the research is being conducted.

5 f. Relationship between the principal investigator and participants.

Is there any relationship between the principal investigator (student), co-investigators(s), (supervisor) and participant(s)? For example, if you are conducting research in a school environment on students in your classroom (e.g. instructor-student).

☐ YES

☒ NO

If YES, specify (use the space provided in the box).

6. Potential Risks of the Proposed Research Study.

6 a. i. Are there any potential risks, psychological harm and/or ethical issues associated with the proposed research study, other than risks pertaining to everyday life events (such as the risk of an accident when travelling to a remote location for data collection)?

☐ YES

☒ NO

If YES, specify below and answer the question 6 a.ii.

6 a.ii Provide information on what measures will be taken in order to exclude or minimise risks described in 6.a.i.

6 b. Choose the appropriate option

	Yes	No
i. Will you obtain written informed consent form from all participants?	☒	☐
ii. Does the research involve as participants, people whose ability to give free and informed consent is in question?	☐	☒
iii. Does this research involve participants who are children under maturity age? If you answered YES to question iii, complete all following questions. If you answered NO to question iii, do not answer Questions iv, v, vi and proceed to Questions vii, viii, ix and x.	☐	☒
iv. Will the research tools be implemented in a professional educational setting in the presence of other adults (i.e. classroom in the presence of a teacher)?	☐	☐
v. Will informed consent be obtained from the legal guardians (i.e. parents) of children?	☐	☐
vi. Will verbal assent be obtained from children?	☐	☐
vii. Will all data be treated as confidential? If NO, explain why confidentiality of the collected data is not appropriate for this proposed research project, providing details of how all participants will be informed of the fact that any data which they will provide will not be confidential.	☒	☐
viii. Will all participants /data collected be anonymous? If NO, explain why and describe the procedures to be used to ensure the anonymity of participants and/or confidentiality of the collected data both during the conduct of the research and in the subsequent release of its findings.	☒	☐

	Yes	No
ix. Have you ensured that personal data and research data collected from participants will be securely stored for five years?	☒	☐
x. Does this research involve the deception of participants? If YES, describe the nature and extent of the deception involved. Explain how and when the deception will be revealed, and who will administer this debrief to the participants:	☐	☒

6 c. i. Are there any other ethical issues associated with the proposed research study that are not already adequately covered in the preceding sections?

☐ Yes ☒ No

If YES, specify (maximum 150 words).

6.c.ii Provide information on what measures will be taken in order to exclude or minimise ethical issues described in 6.c.i.

6 d. Indicate the Risk Rating.

☐ High ☒ Low

7. Further Approvals

Are there any other approvals required (in addition to ethics clearance from UREC) in order to carry out the proposed research study?

☐ YES ☒ NO

If YES, specify (maximum 100 words).

8. Application Checklist

Mark ✓ if the study involves any of the following:

- ☐ Children and young people under 18 years of age, vulnerable population such as children with special educational needs (SEN), racial or ethnic minorities, socioeconomically disadvantaged, pregnant women, elderly, malnourished people, and ill people.
- ☐ Research that foresees risks and disadvantages that would affect any participant of the study such as anxiety, stress, pain or physical discomfort, harm risk (which is more than is expected from everyday life) or any other act that participants might believe is detrimental to their wellbeing and / or has the potential to / will infringe on their human rights / fundamental rights.
- ☐ Risk to the well-being and personal safety of the researcher.
- ☐ Administration of any substance (food / drink / chemicals / pharmaceuticals / supplements / chemical agent or vaccines or other substances (including vitamins or food substances) to human participants.
- ☐ Results that may have an adverse impact on the natural or built environment.

9. Further documents

Check that the following documents are attached to your application:

		ATTACHED	NOT APPLICABLE
1	Recruitment advertisement (if any)	☐	☒
2	Informed Consent Form / Guardian Informed Consent Form	☒	☐
3	Research Tool(s)	☒	☐
4	Gatekeeper Letter	☒	☐
5	Any other approvals required in order to carry out the proposed research study, e.g., institutional permission (e.g. school principal or company director) or approval from a local ethics or professional regulatory body.	☐	☒



10. Final Declaration by Applicants:

- (a) I declare that this application is submitted on the basis that the information it contains is confidential and will only be used by Unicaf University for the explicit purpose of ethical review and monitoring of the conduct of the research proposed project as described in the preceding pages.
- (b) I understand that this information will not be used for any other purpose without my prior consent, excluding use intended to satisfy reporting requirements to relevant regulatory bodies.
- (c) The information in this form, together with any accompanying information, is complete and correct to the best of my knowledge and belief and I take full responsibility for it.
- (d) I undertake to abide by the highest possible international ethical standards governing the Code of Practice for Research Involving Human Participants, as published by the UN WHO Research Ethics Review Committee (ERC) on <http://www.who.int/ethics/research/en/> and to which Unicaf University aspires to.
- (e) In addition to respect any and all relevant professional bodies' codes of conduct and/or ethical guidelines, where applicable, while in pursuit of this research project.



I agree with all points listed under Question 10

Student's Name: George Aluru Otieno

Supervisor's Name: Dr Jairo Montoya-Torres

Date of Application: 15-Dec-2022

Important Note:

Save your completed form (we suggest you also print a copy for your records) and then submit it to your UU Dissertation/project supervisor (tutor). In the case of student projects, the responsibility lies with the Faculty Dissertation/Project Supervisor. If this is a student application, then it should be submitted via the relevant link in the VLE. Please submit only electronically filled in copies; do not hand fill and submit scanned paper copies of this application.



UREC Decision, Version 2.0



Unicaf University Research Ethics Committee Decision

Student's Name: George Aluru Otieno

Student's ID #: R1807D5825968

Supervisor's Name: Dr Jairo Montoya-Torres

Program of Study: UUZ: PhD Doctorate of Philosophy

Offer ID /Group ID: O43516G46416

Dissertation Stage: 3

Research Project Title: Investigating the use of short-term electricity trading to encourage variable renewable energy development in the Eastern African electricity market

Comments: No comments.

Decision*: A. Approved without revision or comments

Date: 31-Jan-2023

*Provisional approval provided at the Dissertation Stage 1, whereas the final approval is provided at the Dissertation stage 3. The student is allowed to proceed to data collection following the final approval.

APPENDIX 5: TRANSMISSION LINE DATA

Existing Cross Border Transmission Lines in the EAPP

Table 7-2

Existing cross border transmission lines in the EAPP

INTERCONNECTION LINE	CAPACITY (MW)	COD	TECH	Voltage (kV)	STATUS
ETHIOPIA-DJIBOUTI	184	2011	AC	230	Existing
ETHIOPIA-SUDAN	240	2013	AC	230	Existing
RWANDA-DRC	4.1	2000	AC	6.6	Existing
RWANDA-DRC	12	1986	AC	110	Existing
RWANDA-UGANDA	4	2000	AC	30	Existing
TANZANIA-UGANDA	70	1992	AC	132	Existing
UGANDA-KENYA	70	2018	AC	132	Existing
BRUNDI-DRC	3.5	2018	AC	70	Existing
DRC-RWANDA	3.5	2018	AC	70	Existing
EGYPT-SUDAN	200	2020	AC	220	Existing
EGYPT-LIBYA	180	1998	AC	220	Existing
EGYPT-JORDAN	450	1998	AC	500	Existing
LIBYA-TUNISIA	150	2000	AC	220	Existing
SUDAN-SOUTH SUDAN	200	2011	AC	220	Existing

Transmission Lines Under Construction.

Table 7-3*Cross border transmission lines under construction in the EAPP*

INTERCONNECTION LINE	CAPACITY (MW)	COD	TECH	Voltage (kV)	STATUS
ETHIOPIA-KENYA	1100	2022	DC	500	Under Construction
RWANDA-DRC	100	2025	AC	220	Under Construction
RWANDA-BRUNDI	27	2023	AC	110/220	Under Construction
RWANDA-UGANDA	342	2023	AC	220	Under Construction
RWANDA-TANZANIA	26.7	2023	AC	220	Under Construction
TANZANIA-KENYA	1500	2023	AC	400	Under Construction
UGANDA-KENYA	300	2023	AC	400/220	Under Construction
EGYPT-SAUDI	3000	2025	DC	500	Under Construction

Transmission Line Under Feasibility

Table 7-4*Cross border transmission lines under feasibility in the EAPP*

INTERCONNECTION LINE	CAPACITY (MW)	COD	TECH	Voltage (kV)	STATUS
ETHIOPIA-SUDAN	1000	2028	AC	500	Feasibility Study
TANZANIA-UGANDA	1500	2027	AC	400	Feasibility Study
TANZANIA-MOZAMBIQUE	1500	2026	AC	400	FS Consultant Procurement
TANZANIA-ZAMBIA	1500	2025	AC	400	Implementation Finance Secured
TANZANIA-MALAWI	1500	2027	AC	400	Under Feasibility Study
TANZANIA - KENYA (Mwanza-Kilgoris Menengai)	1500	2027	AC	400	Under Feasibility Study (second interconnection)
UGANDA-DRC	600	2026	AC	400	Under Feasibility Study

UGANDA-SOUTH SUDAN	600	2026	AC	400	feasibility Study Consultant Procurement
BURUNDI-DRC	49	2025	AC	220	Under Feasibility Study
EGYPT-CYPRUS	1000	2023	DC	500	Under Feasibility Study
EGYPT-CYPRUS	1000	2025	DC	500	Under Feasibility

APPENDIX 6: GENERATION PLANT DATA

APPENDIX 6.1: Kenya Generation Plants 2025

Kenya Generation Plants by 2025

Table 7-5

Kenya Generation Plants by 2025

	Name	Technology	Capacity (MW)	Tariff (USD/kWh)	COD
1	Lake Turkana Wind Farm	Wind	310	0.09	2018
2	Kipeto	Wind	100	0.12	2021
3	Selenkei	Solar	40	0.12	2021
4	Cedate Solar	Solar	40	0.12	2021
5	Malindi Solar	Solar	40	0.12	2022
6	Alten Solar	Solar	40	0.12	2022
7	Kindaruma	Hydro	72	0.02	1968
8	Masinga	Hydro	40	0.02	1981
9	Kamburu	Hydro	94.2	0.02	1974/76
10	Gitaru	Hydro	225	0.02	1978/99
11	Kiambere	Hydro	168	0.02	1988
12	Turkwel	Hydro	106	0.02	1991
13	Sondu	Hydro	60	0.02	2008
14	Olkaria II	Geothermal	105	0.04	2003
15	Olkaria I unit 6	Geothermal	83.3	0.06	2022
16	Olkaria V	Geothermal	165.4	0.06	2022
17	Olkaria I - AU	Geothermal	150	0.06	2014
18	Olkaria IV	Geothermal	150	0.06	2014
19	Orpower4-Plant III	Geothermal	17.6	0.10	2014
20	Orpower4-Plant IV	Geothermal	29	0.10	2016
21	Orpower4-Plant II	Geothermal	39.6	0.10	2009
22	Orpower4-Plant I	Geothermal	63.8	0.10	2000
23	Garissa Solar (REREC)	Solar	50	0.05	2017
24	Eburru Wellheads	Geothermal	2.4	0.05	2012
25	Sang'oro Hydro	Hydro	21	0.04	2012
26	Ngong I Phase I	Wind	5.1	0.07	2009
27	Ngong I Phase II	Wind	6.8	0.07	2015
28	Ngong II	Wind	13.6	0.07	2015
29	Tana	Hydro	20	0.07	2009

30	Wanji	Hydro	7.4	0.07	1952
31	Gogo	Hydro	2	0.07	1958
32	Sagana	Hydro	1.5	0.07	1956
33	Mesco	Hydro	0.433	0.07	1930
34	Sosiani	Hydro	0.4	0.07	1955
35	Ndula HPP	Hydro	2	0.07	1924
36	Genpro SHP	Hydro	5		
37	Mumias Sugar	Bioenergy	26		2008
38	Gura - KTDA	Hydro	2	0.08	2016
39	WellHeads	Geothermal	81.1	0.08	2020
40	North Mathioya (Metumi) KTDA	Hydro	5.61	0.09	2017
41	Regen Terem	Hydro	5.2	0.09	2017
42	Gikira Hydro Power	Hydro	0.514	0.10	2013
43	Biojoule (Biogas)	Bioenergy	2	0.10	2015
44	Chania - KTDA	Hydro	0.5	0.10	2016
45	Kianthumbi	Hydro	0.65	0.10	2020
46	Strathmore	Solar	0.25	0.12	2014
47	Iberafrica	Thermal	52.5	0.18	2004
48	Thika Power	Thermal	87	0.21	2014
49	Rabai Power	Thermal	90	0.17	2009
50	Kipevu Diesel	Thermal	73.5	0.21	1999
51	Gulf Power	Thermal	80.32	0.17	2014
52	Kipevu III Diesel	Thermal	120	0.17	2011
53	Triumph Power	Thermal	83	0.44	2015
54	KTDA Ltd, Lower Nyamindi	Hydro	0.8		2021
55	Kleen Energy Limited	Hydro	6		2020
56	KTDA - Nyambunde, Nyakwana	Hydro	0.5		2021
57	REA Vipingo Plantations Ltd (DWA Estates Ltd)	Bioenergy	1.44		2020
58	Marco Borero Co Ltd.	Solar	1.5		2020
59	KTDA Ltd, South Maara (Greater Meru Power Co.)	Hydro	1.5		2021
60	KTDA Ltd, Iraru	Hydro	1		2020
61	Ergon Solair (Kisumu Solar One Ltd)	Solar	40		2023
62	Menengai I Sosian	Geothermal	35		2021
63	BESS 1	Storage	100		2023
64	BESS 2	Storage	100		2024
65	BESS 3	Storage	50		2025
66	Olkaria I Unit 1 Rehab	Geothermal	21		2024
67	Olkaria I Unit 2 Rehab	Geothermal	21		2024

68	Olkaria I Unit 3 Rehab	Geothermal	21		2024
69	Menengai I Quantum	Geothermal	35		2022
70	Mt Kenya CBO	Hydro	0.6		2022
71	KTDA, Kipsonoi (Settet Power Co.)	Hydro	0.6		2025
72	Gogo Upgrade	Hydro	8.6		2025
73	Kwale Int Sugar Co Ltd	Bioenergy	10		2021
74	Chania Green	Wind	50		2022
75	Wellhead - Olkaria	Geothermal	5	0.08	2017
	Total 2025		3,497.22		

APPENDIX 6.2: UGANDA GENERATION PLANTS 2025

Uganda Generation Plants by 2025

Table 7-6

Uganda Generation Plants by 2025

No.	Name	Technology	COD	Capacity (MW)	Tariff (US cents/kWh)
1	Kilembe Mines Limited- Mubuku I	Small Hydro	1956	5.00	102.7*
2	Eskom	Large Hydro	1954	380.00	54,010.3**
3	Kasese Cobalt Company Limited- Mubuku III	Small Hydro	2008	9.90	5.4
4	Jacobsen Thermal Plant	Thermal	2008	50.00	17.9
5	Bugoye Hydro Limited- Mubuku II	Small Hydro	2009	13.00	8.7
6	Electro-Maxx Uganda Limited	Thermal	2010	50.00	8.0
7	Eco Power Uganda Limited- Ishasha	Small Hydro	2011	6.40	7.5
8	Africa EMS Mpanga	Small Hydro	2011	18.00	6.7
9	Bujagali Energy Limited	Large Hydro	2012	250.00	9.8
10	Hydromax Limited – Buseruka	Small Hydro	2012	9.00	10.0
11	Access Uganda Solar Limited	Solar PV	2016	10.00	11.0
12	Siti I Hydropower Plant	Small Hydro	2017	5.00	10.0
13	Muvumbe Hydropower Plant	Small Hydro	2017	6.50	9.4
14	Tororo Solar North	Solar PV	2017	10.00	11.0
15	Rwimi Hydropower Plant	Small Hydro	2017	5.50	9.8
16	Nyamwamba Hydropower Plant	Small Hydro	2018	9.20	8.5
17	Kakira Sugar Limited	Bagasse	2009	51.10	9.8
18	Kinyara Sugar Limited	Bagasse	2010	14.50	8.1
19	Sugar and Allied Industries Limited	Bagasse	2015	11.90	9.6
20	Sugar Corporation of Uganda Limited	Bagasse	1998	9.50	9.8
21	Lubilia Hydropower Plant	Small Hydro	2018	5.40	9.9
22	Nkusi Hydropower Plant	Small Hydro	2018	9.60	8.5
23	Mahoma Hydropower Plant	Small Hydro	2018	2.70	10.9
24	Waki Hydropower Plant	Small Hydro	2018	4.80	8.5
25	MSS Xsabo Power Limited	Solar PV	2018	20.00	11.0
26	Isimba Hydropower Plant	Large Hydro	2019	183.00	4.2

27	Emerging Power	Solar PV	2019	10.00	11.0
28	Sindila (Butama) Hydropower Plant	Small Hydro	2019	5.30	9.9
29	Siti II Hydropower Plant	Small Hydro	2019	16.50	8.5
30	Ziba Limited (Kyambura) Hydropower Plant	Small Hydro	2019	7.60	9.9
31	Ndugutu Hydropower Plant	Small Hydro	2019	5.90	10.1
32	Achwa II Hydropower Plant	Large Hydro	2019	42.00	10.0
33	Nyamagasani 1 HPP	Hydro	2021	15.00	0.085
34	Nyamagasani 2 HPP	Hydro	2021	6.10	0.096
35	Muyembe HPP	Hydro	2021	6.90	0.092
36	Kabeywa 1 HPP	Hydro	2022	6.50	0.094
37	Kabeywa 2 HPP	Hydro	2023	2.00	0.107
38	Achwa 2 HPP	Hydro	2021	41.00	0.1
39	Karuma HPP	Hydro	2021	600.00	0.048
40	Kikagati HPP	Hydro	2021	14.00	0.085
41	Nyabuhuka HPP	Hydro	2023	3.20	0.107
42	Kakaka HPP	Hydro	2021	5.00	0.100
43	Nyagak III HPP	Hydro	2025	5.50	0.0574
44	Nyamwamba II HPP	Hydro	2025	7.30	0.1
45	Nyamabuye HPP	Hydro	2025	7.00	0.102
46	SCOUL Bagasse Plant	Bagasse	2021	25.00	0.098
47	Rupa Wind Power Project	wind	2023	20.00	0.101
48	Atari HPP	Hydro	2022	3.30	0.107
49	Sironko HPP	Hydro	2025	7.00	0.102
50	Simu HPP	Hydro	2024	9.50	0.095
51	Sisi HPP	Hydro	2024	7.00	0.102
52	Kigwabya HPP	Hydro	2025	4.20	0.0792
53	Hoimo HPP	Hydro	2024	3.30	0.0535
54	Igassa HPP	Hydro	2024	0.30	0.0535
55	Kabasanja HPP	Hydro	2024	0.40	0.0535
56	Tokwe HPP	Hydro	2024	0.30	0.0535
57	Nsongya HPP	Hydro	2024	0.70	0.0535
58	Katooke HPP	Hydro	2024	0.30	0.0535
59	Nchwera HPP	Hydro	2024	0.50	0.0535
60	Warugo HPP	hydro	2024	0.50	0.0535
61	Xsabo Nkoge Solar	Solar	2023	20.00	0.071
	Total Capacity 2025			2,059.10	

APPENDIX 6.3: TANZANIA GENERATION PLANTS 2025

Tanzania Generation Plants by 2025

Table 7-7

Tanzania Generation Plants by 2025

	Plant	Technology	CO D	Fuel	Installed (MW)	Owner
1	TANWAT	Thermal	2010	Bagasse	1.5	IPP
2	TPC	Thermal	2011	Bagasse	9	IPP
3	Ubungo I	Thermal	2007	LNG	102	TANESCO
4	Ubungo II	Thermal	2011	LNG	129	TANESCO
5	Kinyerezi I	Thermal	2015	LNG	150	TANESCO
6	Kinyerezi II	Thermal	2018	LNG	248.2	TANESCO
7	Tegeta	Thermal	2009	LNG	45	TANESCO
8	Mtwara I	Thermal	2007	LNG	18	TANESCO
9	Mtwara II	Thermal	2017	LNG	4	TANESCO
10	Somanga	Thermal	2010	LNG	7.5	TANESCO
11	Nyakato	Thermal	2013	HFO	63	TANESCO
12	Mtera	Hydro	1988	Hydro	80	TANESCO
13	Kidatu	Hydro	1975	Hydro	204	TANESCO
14	Hale	Hydro	1967	Hydro	21	TANESCO
15	Kihansi	Hydro	2000	Hydro	180	TANESCO
16	New Pangani Falls	Hydro	1995	Hydro	68	TANESCO
17	Nyumba ya Mungu	Hydro	1968	Hydro	8	TANESCO
18	Uwemba	Hydro	1991	Hydro	0.84	TANESCO
19	Mwenga	Hydro	2012	Hydro	4	TANESCO
20	Yovi	Hydro	2012	Hydro	0.95	TANESCO
21	Darakuta	Hydro	2013	Hydro	0.32	TANESCO
22	Tulila	Hydro	2015	Hydro	5	TANESCO
23	Kinyerezi I ext	Thermal	2021	LNG	185	
24	Rusumo (80 MW)*	Hydro	2021	Hydro	27	
25	Murongo/Kikagati - (14 MW)*	Hydro	2021	Hydro	7	
26	Julius Nyerere	Hydro	2022	Hydro	2115	TANESCO
27	Singida	Solar	2023	Solar	150	
28	Songwe	Geothermal	2023	Geothermal	5	
29	Ngozi (wellhead) & Ngozi I	Geothermal	2023	Geothermal	30	
30	Malagarasi	Hydro	2024	Hydro	49.5	
31	Dodoma I	Solar	2024	Solar	55	

32	Kiejo – Mbaka	Geothermal	2024	Geothermal	60	
33	Ruhudji	Hydro	2025	Hydro	358	
34	Singida I	Wind	2025	Wind	100	
35	Mtwara I	Gas	2025	CCGT	300	
	Total Capacity 2025				4790.81	

APPENDIX 6.4: ETHIOPIA GENERATION PLANTS 2025

Ethiopia Generation Plants by 2025.

Table 7-8

Ethiopia Generation Plants by 2025

No .	HPP Name	Status	COD	Tehcnolog y	Installe d capacity (MW)	Ownershi p
1	Koka	Existing	1960	Hydro	43	EEP
2	Awash II	Existing	1966	Hydro	32	EEP
3	Awash III	Existing	1971	Hydro	32	EEP
4	Finchaa	Existing	1973	Hydro	128	EEP
5	Melka Wakana	Existing	1988/2014	Hydro	153	EEP
6	Tis Abey II	Existing	2001	Hydro	72	EEP
7	Gibe I	Existing	2004	Hydro	210	EEP
8	Tekeze I	Existing	2009	Hydro	300	EEP
9	Beles	Existing	2010	Hydro	460	EEP
10	Gibe II	Existing	2010	Hydro	420	EEP
11	Neshe	Existing	2013	Hydro	97	EEP
12	Gibe III	Existing	2015	Hydro	1870	EEP
13	Aba Samuel	Existing	2010	Hydro	6	EEP
14	Genale Dawa III	Existing	2021	Hydro	254	EEP
15	Renaissance	Committed	2021-2026	Hydro	5150	EEP
16	Koysha (Gibe IV)	Committed	2024	Hydro	1800	EEP
17	Adama I	Existing	2012	Wind	51	EEP
18	Ashegoda	Existing	2012	Wind	120	EEP
19	Adama II	Existing	2015	Wind	153	EEP
20	Asela-I	Committed	2023	Wind	100	EEP
21	Asela-II (Iteya)	Committed	2024	Wind	150	EEP
22	Ayisha-II	Committed	2022	Wind	120	EEP
23	Ayisha-I	Candidate	2025	Wind	120	EEP
24	Ayisha-IA	Candidate	2024	Wind	150	IPP
25	Ayisha-IB	Candidate	2024	Wind	150	IPP
26	Ayisha-III A	Candidate	2024	Wind	150	IPP
27	Ayisha-IIIB	Candidate	2024	Wind	150	IPP
28	Debre Birhan	Candidate	2025	Wind	125	IPP
29	Deday	Candidate	2025	Wind	125	IPP
30	Sure	Candidate	2025	Wind	150	IPP

31	Tulu Guled	Candidate	2024	Wind	100	IPP
32	Dire Dawa	Candidate	2024	Wind	150	IPP
33	Gode	Candidate	2024	Wind	150	IPP
34	Idabo	Candidate	2024	Wind	150	IPP
35	Adigala	Candidate	2024	Wind	150	IPP
36	Mekele WF	Candidate	2025	Wind	150	IPP
37	Ashegoda	Candidate	2024	Wind	150	IPP
38	KebriBeyah	Candidate	2024	Wind	150	IPP
39	May Mekdan	Candidate	2024	Wind	150	IPP
40	Mega	Candidate	2024	Wind	150	IPP
41	Assosa Bambasi	Candidate	2024	Wind	150	IPP
42	Sela Dingay	Candidate	2024	Wind	100	IPP
43	Reppie EfW	Existing	2017	Bioenergy	25	
44	Beles 1	Committed	2022	Bioenergy	20	IPP
45	Beles 2	Committed	2024	Bioenergy	20	IPP
46	Beles 3	Committed	2025	Bioenergy	20	IPP
47	Wolkayit	Committed	2023	Bioenergy	82	IPP
48	Omo Kuraz 1	Committed	2024	Bioenergy	37	IPP
49	Omo Kuraz 2	Committed	2025	Bioenergy	37	IPP
50	Kessem	Committed	2023	Bioenergy	64	IPP
51	Aluto Langan I (Rehabilitation)	Committed	2023	Geothermal	9.5	EEP
52	Corbetti I	Committed	2024	Geothermal	50	IPP
53	Tulu Moye I	Committed	2023	Geothermal	50	IPP
54	Tulu Moye II	Committed	2025	Geothermal	100	IPP
55	Gad-I solar	Committed	2023	Solar PV	125	IPP
56	Dicheto solar	Committed	2023	Solar PV	125	IPP
57	Metehara solar	Candidate	2024	Solar PV	100	IPP
58	Humera solar	Candidate	2024	Solar PV	125	IPP
59	Mekele solar	Candidate	2024	Solar PV	100	IPP
60	Welenchiti solar	Candidate	2024	Solar PV	150	IPP
61	Weranso solar	Candidate	2024	Solar PV	150	IPP
62	Metema solar	Candidate	2024	Solar PV	125	IPP
63	Gad-II solar	Candidate	2024	Solar PV	125	IPP
64	Yirgalem Solar	Candidate	2025	Solar PV	100	IPP
65	Melkasedi Solar	Candidate	2025	Solar PV	150	IPP
66	Meki Solar	Candidate	2025	Solar PV	100	IPP
67	Wereta Solar	Candidate	2025	Solar PV	100	IPP
68	Meshenti Solar	Candidate	2025	Solar PV	100	IPP
	Total Capacity 2025				16730.5	

APPENDIX 6.5: RWANDA GENERATION PLANTS 2025

Rwanda Generation Plants by 2025 (Rwanda Energy Group, 2022)

Table 7-9

Rwanda Generation Plants by 2025

	Plant Name	Technology	CO D	Installed Capacity (MW)	Capacity Factor (%)	Owner
1	Ntaruka	Hydro	1959	11.25	23	GoR
2	Mukungwa I	Hydro	1982	12	50	GoR
3	Nyabarongo I	Hydro	2014	28	48	GoR
4	Gisenyi	Hydro	1957	1.7	65	Prime Energy
5	Gihira	Hydro	1984	1.8	70	RMT
6	Murunda	Hydro	2010	0.1	45	Repro
7	Rukarara I	Hydro	2010	9	40	Ngali Energy
8	Rugezi	Hydro	2011	2.6	50	RMT
9	Keya	Hydro	2011	2.2	50	Adre Hydro&Energicote l
10	Nyamyotsi I	Hydro	2011	0.1	60	Adre Hydro&Energicote l
11	Nyamyotsi II	Hydro	2011	0.1	60	Adre Hydro&Energicote l
12	Agatobwe	Hydro	2010	0.39	35	Carera-Ederer
13	Mutobo	Hydro	2009	0.2	45	Repro
14	Nkora	Hydro	2011	0.68	50	Adre Hydro&Energicote l
15	Cyimbili	Hydro	2011	0.3	50	Adre Hydro&Energicote l
16	Gaseke	Hydro	2017	0.5	90	Novel Energy
17	Mazimeru	Hydro	2012	0.5	49	Carera-Ederer
18	Janja	Hydro	2012	0.2	80	RGE Energy UK ltd
19	Gashashi	Hydro	2013	0.28	40	Prime Energy
20	Nyabahanga I	Hydro	2012	0.2	55	GoR
21	Nshili I	Hydro	2012	0.4	60	GoR

22	Rwaza Muko	Hydro	2018	2.6	60	Rwaza HydroPower Ltd
23	Musarara	Hydro	2013	0.4	49	Amahoro Energy
24	Mukungwa II	Hydro	2013	3.6	73	Prime Energy
25	Rukarara II	Hydro	2013	2.2	52.5	Prime Energy
26	Nyirabuhombohombo	Hydro	2013	0.65	35	RGE Energy UK ltd
27	Giciye I	Hydro	2013	4	40	RMT
28	Giciye II	Hydro	2016	4	40	RMT
29	Giciye III	Hydro	2020	9.8	40	RMT
30	Rukarara V Mushishito	Hydro	2019	5	60	IPP
31	Rubagabaga	Hydro	2019	0.45	61	Rubagabaga Hydropower Ltd
32	Nyirantaruko	Hydro	2020	1.84	65	IPP
33	Kigasa	Hydro	2020	0.272	37	IPP
34	Mukungu MHPP	Hydro	2020	0.016	60	IPP
35	Jabana 1	Thermal	2004	7.8	95	GoR
36	Jabana 2	Thermal	2009	21	95	GoR
37	SO Energy	Thermal	2017	30	95	So Energy&SP
38	Gishoma	Peat	2016	15	95	GoR
39	Hakan	Peat	2021	35	95	Hakan
40	Kivuwatt Phase I	Methane	2016	26.19	100	Contour Global
41	KP1	Methane	2009	3.6	100	GoR
42	Jali	Solar	2007	0.25	14	Mainz Stadwerke / Local Agency
43	GigaWatt	Solar	2013	8.5	14	Gigawatt Global
44	Nasho Solar	Solar	2017	3.3	35	GoR
45	Mururu 1	Hydro	1957	4.1	100	SNEL Sarl - Import
46	Mururu II	Hydro	1957	12	100	SNEL Sarl - Import
47	Hakan (Unit_2)	Thermal	2023	35		
48	Symbion (_1)	Thermal	2023	28		
49	Symbion (_2)	Thermal	2023	28		
50	Ntaruka A	Hydro	2022	2.1		
51	Kavumu MHPP	Hydro	2023	0.38		
52	Nyirahindwe 1	Hydro	2023	0.909		
53	Nyirahindwe 2	Hydro	2023	0.359		
54	Base 1	Hydro	2025	2.9		
55	Kore	Hydro	2024	1.3		
56	Rukore	Hydro	2023	2		
57	Rukarara VI	Hydro	2024	9.76		
58	Rusumo	Hydro	2022	26.7		
	Total 2025			411.5		

APPENDIX 7: TABLE OF MODELLED POWER PLANTS

Table 7-10

Modelled powerplants in the research

	Power plant Code	Base Installed Power (MW)	High RE Installed Power (MW)
Hydro Power Plant			
Uganda	10	1,757.10	1,757.10
Kenya	11	859.01	859.01
Tanzania	12	2,770.00	3,128.61
Ethiopia	13	9,830.00	9,830.00
Rwanda	14	169.84	169.84
Thermal Power Plant (HFO)			
Uganda	20	100.00	100.00
Kenya	21	586.32	586.32
Rwanda	24	149.80	149.80
Thermal Power Plant (LNG)			
Tanzania	32	962.00	1,262.20
Thermal Power Plant (CH4)			
Rwanda	34	30.00	29.79
Geothermal Power Plant			
Kenya	41	1,025.20	1,025.20
Tanzania	42	-	95.00
Ethiopia	43	-	207.30
Bioenergy Power Plant			
Uganda	50	87.00	112.00
Kenya	51	39.44	39.44
Ethiopia	53	86.00	136.00
Rwanda -Peat	54	50.00	50.00

Storage (Battery) Plant			
Kenya	81	-	250.00
Solar Capacity			
Uganda	60	50.00	70.00
Kenya	61	251.75	251.75
Tanzania	62	-	205.00
Ethiopia	63	-	1,675.00
Rwanda	64	12.05	12.05
Wind Capacity			
Uganda	70	-	20.00
Kenya	71	435.50	485.50
Tanzania	72	-	100.00
Ethiopia	73	324.00	3,514.00
Total Capacity		19,575.00	26,120.90

APPENDIX 8: BASE SCENARIO YAML FILE

```
# AMIRIS scenario for East African day-ahead electricity market in 2025. RW, UG, KE, TZ
and ET
# Modelling is done for Power Plants existing or under construction, anticipated to be
operating in 2025
# Latest version at: https://gitlab.com/dlr-ve/esy/amiris/examples/
# Built for AMIRIS version: see project README at: ../README.md
```

```
Schema: !include "schema.yaml"
```

GeneralProperties:

```
RunId: 1
Simulation:
  StartTime: 2024-12-30_23:58:00
  StopTime: 2025-12-31_23:58:00
  RandomSeed: 1
Output:
  Interval: 100
  Process: 0
```

Variables:

```
- &portfolioBuildingOffset 60
```

Agents:

```
- Type: DayAheadMarketSingleZone
  Id: 1
  Attributes:
    Clearing:
      DistributionMethod: SAME_SHARES
      GateClosureInfoOffsetInSeconds: 11

- Type: CarbonMarket
  Id: 3
  Attributes:
    OperationMode: FIXED
    Co2Prices: "../timeseries/TS_CO2_Price.csv"
```

Sources:

```
# LIGNITE and NUCLEAR are own estimates.
# Fuel costs https://www.bmwi.de/Redaktion/DE/Artikel/Energie/energiedaten-gesamtausgabe.html, Table 26
# Transportation costs
https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strommaerkten.pdf?\_\_blob=publicationFile&v=18, p. 163
- Type: FuelsMarket
```

Id: 4

Attributes:

FuelPrices:

- FuelType: NUCLEAR
Price: 2.00
ConversionFactor: 1.0
- FuelType: LIGNITE
Price: 35.080616 # Factoring in the cost of Geothermal
ConversionFactor: 1.0
- FuelType: HARD_COAL
Price: 0
ConversionFactor: 1.0
- FuelType: NATURAL_GAS
Price: "/timeseries/TS_Natural_Gas_Cost.csv"
ConversionFactor: 1.0
- FuelType: OIL
Price: "/timeseries/TS_Oil_HFO_Cost.csv"
ConversionFactor: 1.0

- Type: DemandTrader

Id: 100

Attributes:

Loads:

- ValueOfLostLoad: 1500.0
DemandSeries: "/timeseries/TS_Demand_EA.csv"

- Type: MeritOrderForecaster

Id: 6

Attributes:

Clearing:

- DistributionMethod: SAME_SHARES
- ForecastPeriodInHours: 168
- ForecastRequestOffsetInSeconds: 27

- Type: StorageTrader #Pumped Hydro Used to represent Battery

Id: 81

Attributes:

ElectricityForecastRequestOffsetInSeconds: 22

Device:

- EnergyToPowerRatio: 5.0
- SelfDischargeRatePerHour: 0.0
- ChargingEfficiency: 0.89
- DischargingEfficiency: 0.89
- InitialEnergyLevelInMWH: 0
- InstalledPowerInMW: 0

Strategy:

StrategistType: SINGLE_AGENT_MIN_SYSTEM_COST

ForecastPeriodInHours: 168
 ScheduleDurationInHours: 24
 SingleAgent:
 ModelledChargingSteps: 50

- Type: RenewableTrader
 Id: 91
 Attributes:
 ShareOfRevenues: 0.0
- Type: NoSupportTrader
 Id: 92
 Attributes:
 ShareOfRevenues: 0.0
- Type: SystemOperatorTrader
 Id: 3093
- Type: SystemOperatorTrader
 Id: 3094
- Type: SystemOperatorTrader
 Id: 3095
- Type: SystemOperatorTrader
 Id: 3096
- Type: SystemOperatorTrader
 Id: 3097
- Type: SystemOperatorTrader
 Id: 3098
- Type: SystemOperatorTrader
 Id: 3099
- Type: SupportPolicy
 Id: 90
 Attributes:
 SetSupportData:
 - Set: PvFit
 FIT:
 TsFit: 112.982485
 - Set: WindOnFit
 FIT:
 TsFit: 92.009872
 - Set: RunOfRiver

FIT:

TsFit: 60.32

- Set: PvMpvarCluster1

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster3

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster4

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster5

MPVAR:

Lcoe: 50.22

- Set: WindOnMpvarCluster1

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster3

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster4

MPVAR:

Lcoe: 61.38

Kenyan Geothermal Plants

- Type: ConventionalPlantOperator

Id: 41

- Type: PredefinedPlantBuilder

Id: 2001

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 35

InstalledPowerInMW: 1025.

- Type: ConventionalTrader

Id: 1001

Attributes:

minMarkup: -60

maxMarkup: 0

Tanzania Geothermal Plant

- Type: ConventionalPlantOperator

Id: 42

- Type: PredefinedPlantBuilder

Id: 2002

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 0

InstalledPowerInMW: 0

- Type: ConventionalTrader

Id: 1002

Attributes:

minMarkup: -60

maxMarkup: 0

Ethiopia Geothermal Plant

- Type: ConventionalPlantOperator

Id: 43

- Type: PredefinedPlantBuilder

Id: 2003

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.3108
 Maximal: 0.45
 BlockSizeInMW: 0
 InstalledPowerInMW: 0

- Type: ConventionalTrader
- Id: 1003
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Tanzanian LNG Plants

- Type: ConventionalPlantOperator
- Id: 32

- Type: PredefinedPlantBuilder
- Id: 2032
- Attributes:
 - PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 - Prototype: #Confirm Tanzania LNG prices/MWh
 - FuelType: NATURAL_GAS #gasTurbine
 - SpecificCo2EmissionsInTperMWH: 0.201
 - PlannedAvailability: 1.0
 - UnplannedAvailabilityFactor: 0.97
 - OpexVarInEURperMWH: 1.2
 - CyclingCostInEURperMW: 0.0
 - Efficiency:
 - Minimal: 0.327
 - Maximal: 0.449
 - BlockSizeInMW: 105.17
 - InstalledPowerInMW: 962.0

- Type: ConventionalTrader
- Id: 1032
- Attributes:
 - minMarkup: 100
 - maxMarkup: 100

Rwanda Methane Plant

- Type: ConventionalPlantOperator
- Id: 34

- Type: PredefinedPlantBuilder

Id: 2004

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: NATURAL_GAS #gasTurbine

SpecificCo2EmissionsInTperMWH: 0.201

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.97

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.327

Maximal: 0.449

BlockSizeInMW: 10.0

InstalledPowerInMW: 30.

- Type: ConventionalTrader

Id: 1004

Attributes:

minMarkup: 100

maxMarkup: 100

Ugandan HFO Plants

- Type: ConventionalPlantOperator

Id: 20

- Type: PredefinedPlantBuilder

Id: 2000

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.6

InstalledPowerInMW: 100.

- Type: ConventionalTrader

Id: 1000

Attributes:

minMarkup: 0
maxMarkup: 0

Kenyan HFO Plants

- Type: ConventionalPlantOperator
Id: 21

- Type: PredefinedPlantBuilder
Id: 2021

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.76

InstalledPowerInMW: 586.32

- Type: ConventionalTrader
Id: 1021

Attributes:

minMarkup: 0

maxMarkup: 0

Rwanda HFO Plant

- Type: ConventionalPlantOperator
Id: 24

- Type: PredefinedPlantBuilder
Id: 2024

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:
 Minimal: 0.311
 Maximal: 0.397
 BlockSizeInMW: 16.60
 InstalledPowerInMW: 149.8

- Type: ConventionalTrader
 Id: 1024
 Attributes:
 minMarkup: 0
 maxMarkup: 0

Kenya Solar

- Type: VariableRenewableOperator
 Id: 61
 Attributes:
 Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 251.75
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Kenya Wind

- Type: VariableRenewableOperator
 Id: 71
 Attributes:
 Set: WindOnFit
 SupportInstrument: FIT
 EnergyCarrier: WindOn
 InstalledPowerInMW: 435.5
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Uganda Hydro

- Type: VariableRenewableOperator
 Id: 10
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 1757.1
 OpexVarInEURperMWH: 55.27
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Kenya Hydro

- Type: VariableRenewableOperator
 Id: 11
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 859.01
 OpexVarInEURperMWH: 26.93141
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Tanzania Hydro

- Type: VariableRenewableOperator
 Id: 12
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 2770
 OpexVarInEURperMWH: 26.93141
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Ethiopia Hydro

- Type: VariableRenewableOperator
 Id: 13
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 9830
 OpexVarInEURperMWH: 60.32
 YieldProfile: "./timeseries/TS_Hydro_Profile_ET.csv"

Rwanda Hydro

- Type: VariableRenewableOperator
 Id: 14
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 169.84
 OpexVarInEURperMWH: 26.93141

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Uganda Bioenergy

- Type: Biogas

Id: 50

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 87.0

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Kenya Bioenergy

- Type: Biogas

Id: 51

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 39.44

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Ethiopia Bioenergy

- Type: Biogas

Id: 53

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 86.0

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Rwanda Bioenergy

- Type: Biogas

Id: 54

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 50.0

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Uganda Solar

- Type: VariableRenewableOperator
- Id: 60
- Attributes:
 - Set: PvMpvarCluster1
 - EnergyCarrier: PV
 - SupportInstrument: MPVAR
 - InstalledPowerInMW: 50.0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Tanzania Solar

- Type: VariableRenewableOperator
- Id: 62
- Attributes:
 - Set: PvMpvarCluster3
 - EnergyCarrier: PV
 - SupportInstrument: MPVAR
 - InstalledPowerInMW: 0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Ethiopia Solar

- Type: VariableRenewableOperator
- Id: 63
- Attributes:
 - Set: PvMpvarCluster4
 - EnergyCarrier: PV
 - SupportInstrument: MPVAR
 - InstalledPowerInMW: 0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Rwanda Solar

- Type: VariableRenewableOperator
- Id: 64
- Attributes:
 - Set: PvMpvarCluster5
 - EnergyCarrier: PV
 - SupportInstrument: MPVAR
 - InstalledPowerInMW: 12.0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Uganda Wind

```
- Type: VariableRenewableOperator
  Id: 70
  Attributes:
    Set: WindOnMpvarCluster1
    SupportInstrument: MPVAR
    EnergyCarrier: WindOn
    InstalledPowerInMW: 0
    OpexVarInEURperMWH: 0.0
    YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_UG.csv"
```

Tanzania Wind

```
- Type: VariableRenewableOperator
  Id: 72
  Attributes:
    Set: WindOnMpvarCluster3
    SupportInstrument: MPVAR
    EnergyCarrier: WindOn
    InstalledPowerInMW: 0
    OpexVarInEURperMWH: 0.0
    YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"
```

Ethiopia Wind

```
- Type: VariableRenewableOperator
  Id: 73
  Attributes:
    Set: WindOnMpvarCluster4
    SupportInstrument: MPVAR
    EnergyCarrier: WindOn
    InstalledPowerInMW: 324.0
    OpexVarInEURperMWH: 0.0
    YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_ET.csv"
```

```
Contracts: !include ["contracts/*.yaml", "Contracts"]
```

APPENDIX 9: HIGH RE SCENARIO YAML FILE

```
# AMIRIS scenario for East African day-ahead electricity market in 2025. RW, UG, KE, TZ
and ET
# Modelling done based on powerplants expected to be operational by 2025, high renewable
scenario
# Latest version at: https://gitlab.com/dlr-ve/esy/amiris/examples/
# Built for AMIRIS version: see project README at: ../README.md
```

```
Schema: !include "schema.yaml"
```

GeneralProperties:

```
RunId: 1
Simulation:
  StartTime: 2024-12-30_23:58:00
  StopTime: 2025-12-31_23:58:00
  RandomSeed: 1
Output:
  Interval: 100
  Process: 0
```

Variables:

```
- &portfolioBuildingOffset 60
```

Agents:

```
- Type: DayAheadMarketSingleZone
  Id: 1
  Attributes:
    Clearing:
      DistributionMethod: SAME_SHARES
      GateClosureInfoOffsetInSeconds: 11

- Type: CarbonMarket
  Id: 3
  Attributes:
    OperationMode: FIXED
    Co2Prices: "../timeseries/TS_CO2_Price.csv"
```

Sources:

```
# LIGNITE and NUCLEAR are own estimates.
# Fuel costs https://www.bmwi.de/Redaktion/DE/Artikel/Energie/energiedaten-gesamtausgabe.html, Table 26
# Transportation costs
https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strommaerkten.pdf?\_\_blob=publicationFile&v=18, p. 163
- Type: FuelsMarket
```

Id: 4

Attributes:

FuelPrices:

- FuelType: NUCLEAR
Price: 2.00
ConversionFactor: 1.0
- FuelType: LIGNITE
Price: 35.080616 # Factoring in the cost of Geothermal
ConversionFactor: 1.0
- FuelType: HARD_COAL
Price: 0
ConversionFactor: 1.0
- FuelType: NATURAL_GAS
Price: "/timeseries/TS_Natural_Gas_Cost.csv"
ConversionFactor: 1.0
- FuelType: OIL
Price: "/timeseries/TS_Oil_HFO_Cost.csv"
ConversionFactor: 1.0

- Type: DemandTrader

Id: 100

Attributes:

Loads:

- ValueOfLostLoad: 1500.0
DemandSeries: "/timeseries/TS_Demand_EA.csv"

- Type: MeritOrderForecaster

Id: 6

Attributes:

Clearing:

- DistributionMethod: SAME_SHARES
- ForecastPeriodInHours: 168
- ForecastRequestOffsetInSeconds: 27

- Type: StorageTrader #Pumped Hydro Used to represent Battery

Id: 81

Attributes:

ElectricityForecastRequestOffsetInSeconds: 22

Device:

- EnergyToPowerRatio: 5.0
- SelfDischargeRatePerHour: 0.0
- ChargingEfficiency: 0.89
- DischargingEfficiency: 0.89
- InitialEnergyLevelInMWH: 1000
- InstalledPowerInMW: 250

Strategy:

StrategistType: SINGLE_AGENT_MIN_SYSTEM_COST

ForecastPeriodInHours: 168
 ScheduleDurationInHours: 24
 SingleAgent:
 ModelledChargingSteps: 50

- Type: RenewableTrader
 Id: 91
 Attributes:
 ShareOfRevenues: 0.0
- Type: NoSupportTrader
 Id: 92
 Attributes:
 ShareOfRevenues: 0.0
- Type: SystemOperatorTrader
 Id: 3093
- Type: SystemOperatorTrader
 Id: 3094
- Type: SystemOperatorTrader
 Id: 3095
- Type: SystemOperatorTrader
 Id: 3096
- Type: SystemOperatorTrader
 Id: 3097
- Type: SystemOperatorTrader
 Id: 3098
- Type: SystemOperatorTrader
 Id: 3099
- Type: SupportPolicy
 Id: 90
 Attributes:
 SetSupportData:
 - Set: PvFit
 FIT:
 TsFit: 112.982485
 - Set: WindOnFit
 FIT:
 TsFit: 92.009872
 - Set: RunOfRiver

FIT:

TsFit: 60.32

- Set: PvMpvarCluster1

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster3

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster4

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster5

MPVAR:

Lcoe: 50.22

- Set: WindOnMpvarCluster1

MPVAR:

Lcoe: 70.58

- Set: WindOnMpvarCluster3

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster4

MPVAR:

Lcoe: 61.38

Kenyan Geothermal Plants

- Type: ConventionalPlantOperator

Id: 41

- Type: PredefinedPlantBuilder

Id: 2001

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 35

InstalledPowerInMW: 1025.

- Type: ConventionalTrader

Id: 1001

Attributes:

minMarkup: -60

maxMarkup: 0

Tanzania Geothermal Plant

- Type: ConventionalPlantOperator

Id: 42

- Type: PredefinedPlantBuilder

Id: 2002

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 31.67

InstalledPowerInMW: 95.

- Type: ConventionalTrader

Id: 1002

Attributes:

minMarkup: -60

maxMarkup: 0

Ethiopia Geothermal Plant

- Type: ConventionalPlantOperator

Id: 43

- Type: PredefinedPlantBuilder

Id: 2003

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98
 OpexVarInEURperMWH: 2.0
 CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.3108
 Maximal: 0.45
 BlockSizeInMW: 34
 InstalledPowerInMW: 207.3

- Type: ConventionalTrader
- Id: 1003
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Tanzanian LNG Plants

- Type: ConventionalPlantOperator
- Id: 32
- Type: PredefinedPlantBuilder
- Id: 2032
- Attributes:
 - PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 - Prototype: #Confirm Tanzania LNG prices/MWh
 - FuelType: NATURAL_GAS #gasTurbine
 - SpecificCo2EmissionsInTperMWH: 0.201
 - PlannedAvailability: 1.0
 - UnplannedAvailabilityFactor: 0.97
 - OpexVarInEURperMWH: 1.2
 - CyclingCostInEURperMW: 0.0
 - Efficiency:
 - Minimal: 0.327
 - Maximal: 0.449
 - BlockSizeInMW: 105.17
 - InstalledPowerInMW: 1262.
- Type: ConventionalTrader
- Id: 1032
- Attributes:
 - minMarkup: 100
 - maxMarkup: 100

Rwanda Methane Plant

- Type: ConventionalPlantOperator
- Id: 34

- Type: PredefinedPlantBuilder

Id: 2004

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: NATURAL_GAS #gasTurbine

SpecificCo2EmissionsInTperMWH: 0.201

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.97

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.327

Maximal: 0.449

BlockSizeInMW: 10.0

InstalledPowerInMW: 30.

- Type: ConventionalTrader

Id: 1004

Attributes:

minMarkup: 100

maxMarkup: 100

Kenyan HFO Plants

- Type: ConventionalPlantOperator

Id: 21

- Type: PredefinedPlantBuilder

Id: 2021

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.76

InstalledPowerInMW: 586.32

- Type: ConventionalTrader

Id: 1021

Attributes:

minMarkup: 0

maxMarkup: 0

Ugandan HFO Plants

- Type: ConventionalPlantOperator

Id: 20

- Type: PredefinedPlantBuilder

Id: 2000

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.6

InstalledPowerInMW: 100.

- Type: ConventionalTrader

Id: 1000

Attributes:

minMarkup: 0

maxMarkup: 0

Rwanda HFO Plant

- Type: ConventionalPlantOperator

Id: 24

- Type: PredefinedPlantBuilder

Id: 2024

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2
 CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.311
 Maximal: 0.397
 BlockSizeInMW: 16.60
 InstalledPowerInMW: 149.8

- Type: ConventionalTrader
 Id: 1024
 Attributes:
 minMarkup: 0
 maxMarkup: 0

Kenya Solar

- Type: VariableRenewableOperator
 Id: 61
 Attributes:
 Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 251.75
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Kenya Wind

- Type: VariableRenewableOperator
 Id: 71
 Attributes:
 Set: WindOnFit
 SupportInstrument: FIT
 EnergyCarrier: WindOn
 InstalledPowerInMW: 485.5 # Consider taking out Ngong wind to Lcoe
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Uganda Hydro

- Type: VariableRenewableOperator
 Id: 10
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 1757.1

OpexVarInEURperMWH: 55.27
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Kenya Hydro

- Type: VariableRenewableOperator
 Id: 11
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 859.01
 OpexVarInEURperMWH: 26.93141
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Tanzania Hydro

- Type: VariableRenewableOperator
 Id: 12
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 3128.61
 OpexVarInEURperMWH: 55.27
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Ethiopia Hydro

- Type: VariableRenewableOperator
 Id: 13
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 9830
 OpexVarInEURperMWH: 60.32
 YieldProfile: "./timeseries/TS_Hydro_Profile_ET.csv"

Rwanda Hydro

- Type: VariableRenewableOperator
 Id: 14
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver

InstalledPowerInMW: 169.84
 OpexVarInEURperMWH: 26.93141
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Uganda Bioenergy

- Type: Biogas
 Id: 50
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 112.
 OpexVarInEURperMWH: 0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Kenya Bioenergy

- Type: Biogas
 Id: 51
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 39.44
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Ethiopia Bioenergy

- Type: Biogas
 Id: 53
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 136.
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Rwanda Bioenergy

- Type: Biogas
 Id: 54
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 50.
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Uganda Solar

- Type: VariableRenewableOperator
 Id: 60
 Attributes:
 Set: PvMpvarCluster1
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 70.
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Tanzania Solar

- Type: VariableRenewableOperator
 Id: 62
 Attributes:
 Set: PvMpvarCluster3
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 205
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Ethiopia Solar

- Type: VariableRenewableOperator
 Id: 63
 Attributes:
 Set: PvMpvarCluster4
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 1675.
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Rwanda Solar

- Type: VariableRenewableOperator
 Id: 64
 Attributes:
 Set: PvMpvarCluster5
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 12.
 OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Uganda Wind

- Type: VariableRenewableOperator
- Id: 70
- Attributes:
 - Set: WindOnMpvarCluster1
 - SupportInstrument: MPVAR
 - EnergyCarrier: WindOn
 - InstalledPowerInMW: 20
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_UG.csv"

Tanzania Wind

- Type: VariableRenewableOperator
- Id: 72
- Attributes:
 - Set: WindOnMpvarCluster3
 - SupportInstrument: MPVAR
 - EnergyCarrier: WindOn
 - InstalledPowerInMW: 100.0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Ethiopia Wind

- Type: VariableRenewableOperator
- Id: 73
- Attributes:
 - Set: WindOnMpvarCluster4
 - SupportInstrument: MPVAR
 - EnergyCarrier: WindOn
 - InstalledPowerInMW: 3514
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_ET.csv"

Contracts: !include ["contracts/*.yaml", "Contracts"]

APPENDIX 10: MEDIUM RE SCENARIO YAML FILE

```
# AMIRIS scenario for East African day-ahead electricity market in 2025. RW, UG, KE, TZ
and ET
# MEDIUM RENEWABLE SCENARIO: Capacities are midpoint between
scenarioBase.yaml and scenarioHighRE.yaml
# Total installed capacity: ~22,348 MW (+2,773 MW vs Base, halfway to High RE's +5,546
MW)
# Key additions vs Base: ET Wind 1,919 MW (+1,595), ET Solar 837.5 MW (+837.5),
# TZ Hydro 2,949 MW (+179), Storage 125 MW, TZ/ET Geothermal 151 MW
# Latest version at: https://gitlab.com/dlr-ve/esy/amiris/examples/
# Built for AMIRIS version: see project README at: ../README.md
```

```
Schema: !include "schema.yaml"
```

GeneralProperties:

```
RunId: 2
Simulation:
  StartTime: 2024-12-30_23:58:00
  StopTime: 2025-12-31_23:58:00
  RandomSeed: 1
Output:
  Interval: 100
  Process: 0
```

Variables:

```
- &portfolioBuildingOffset 60
```

Agents:

```
- Type: DayAheadMarketSingleZone
  Id: 1
  Attributes:
    Clearing:
      DistributionMethod: SAME_SHARES
      GateClosureInfoOffsetInSeconds: 11

- Type: CarbonMarket
  Id: 3
  Attributes:
    OperationMode: FIXED
    Co2Prices: "../timeseries/TS_CO2_Price.csv"
```

```
# Sources:
```


LIGNITE and NUCLEAR are own estimates.

Fuel costs <https://www.bmwi.de/Redaktion/DE/Artikel/Energie/energiedaten-gesamtausgabe.html>, Table 26

Transportation costs

https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strommaerkten.pdf?__blob=publicationFile&v=18, p. 163

- Type: FuelsMarket

Id: 4

Attributes:

FuelPrices:

- FuelType: NUCLEAR

Price: 2.00

ConversionFactor: 1.0

- FuelType: LIGNITE

Price: 35.080616

Factoring in the cost of Geothermal

ConversionFactor: 1.0

- FuelType: HARD_COAL

Price: 0

ConversionFactor: 1.0

- FuelType: NATURAL_GAS

Price: "/timeseries/TS_Natural_Gas_Cost.csv"

ConversionFactor: 1.0

- FuelType: OIL

Price: "/timeseries/TS_Oil_HFO_Cost.csv"

ConversionFactor: 1.0

- Type: DemandTrader

Id: 100

Attributes:

Loads:

- ValueOfLostLoad: 1500.0

DemandSeries: "/timeseries/TS_Demand_EA.csv"

- Type: MeritOrderForecaster

Id: 6

Attributes:

Clearing:

DistributionMethod: SAME_SHARES

ForecastPeriodInHours: 168

ForecastRequestOffsetInSeconds: 27

- Type: StorageTrader #Pumped Hydro Used to represent Battery

Id: 81

Attributes:

ElectricityForecastRequestOffsetInSeconds: 22

Device:

EnergyToPowerRatio: 5.0

SelfDischargeRatePerHour: 0.0

ChargingEfficiency: 0.89

DischargingEfficiency: 0.89

InitialEnergyLevelInMWH: 625

InstalledPowerInMW: 125

Strategy:

StrategistType: SINGLE_AGENT_MIN_SYSTEM_COST

ForecastPeriodInHours: 168

ScheduleDurationInHours: 24

SingleAgent:

ModelledChargingSteps: 50

- Type: RenewableTrader

Id: 91

Attributes:

ShareOfRevenues: 0.0

- Type: NoSupportTrader

Id: 92

Attributes:

ShareOfRevenues: 0.0

- Type: SystemOperatorTrader

Id: 3093

- Type: SystemOperatorTrader

Id: 3094

- Type: SystemOperatorTrader

Id: 3095

- Type: SystemOperatorTrader

Id: 3096

- Type: SystemOperatorTrader

Id: 3097

- Type: SystemOperatorTrader

Id: 3098

- Type: SystemOperatorTrader
Id: 3099

- Type: SupportPolicy
Id: 90

Attributes:

SetSupportData:

- Set: PvFit

FIT:

TsFit: 112.982485

- Set: WindOnFit

FIT:

TsFit: 92.009872

- Set: RunOfRiver

FIT:

TsFit: 60.32

- Set: PvMpvarCluster1

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster3

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster4

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster5

MPVAR:

Lcoe: 50.22

- Set: WindOnMpvarCluster1

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster3

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster4

MPVAR:

Lcoe: 61.38

Kenyan Geothermal Plants

- Type: ConventionalPlantOperator
Id: 41

- Type: PredefinedPlantBuilder

Id: 2001

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 35

InstalledPowerInMW: 1025.

- Type: ConventionalTrader

Id: 1001

Attributes:

minMarkup: -60

maxMarkup: 0

Tanzania Geothermal Plant

- Type: ConventionalPlantOperator

Id: 42

- Type: PredefinedPlantBuilder

Id: 2002

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 31.67
 InstalledPowerInMW: 47.5

- Type: ConventionalTrader
- Id: 1002
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Ethiopia Geothermal Plant

- Type: ConventionalPlantOperator
- Id: 43
- Type: PredefinedPlantBuilder
- Id: 2003
- Attributes:
 - PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 - Prototype:
 - FuelType: LIGNITE # to be replaced with geothermal
 - SpecificCo2EmissionsInTperMWH: 0.0
 - PlannedAvailability: 1.0
 - UnplannedAvailabilityFactor: 0.98
 - OpexVarInEURperMWH: 2.0
 - CyclingCostInEURperMW: 0.0
 - Efficiency:
 - Minimal: 0.3108
 - Maximal: 0.45
 - BlockSizeInMW: 34
 - InstalledPowerInMW: 103.65
- Type: ConventionalTrader
- Id: 1003
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Tanzanian LNG Plants

- Type: ConventionalPlantOperator
- Id: 32
- Type: PredefinedPlantBuilder

Id: 2032

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 Prototype: #Confirm Tanzania LNG prices/MWh
 FuelType: NATURAL_GAS #gasTurbine
 SpecificCo2EmissionsInTperMWH: 0.201
 PlannedAvailability: 1.0
 UnplannedAvailabilityFactor: 0.97
 OpexVarInEURperMWH: 1.2
 CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.327
 Maximal: 0.449
 BlockSizeInMW: 105.17
 InstalledPowerInMW: 1112.0

- Type: ConventionalTrader

Id: 1032

Attributes:

minMarkup: 100
 maxMarkup: 100

Rwanda Methane Plant

- Type: ConventionalPlantOperator

Id: 34

- Type: PredefinedPlantBuilder

Id: 2004

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 Prototype:
 FuelType: NATURAL_GAS #gasTurbine
 SpecificCo2EmissionsInTperMWH: 0.201
 PlannedAvailability: 1.0
 UnplannedAvailabilityFactor: 0.97
 OpexVarInEURperMWH: 1.2
 CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.327
 Maximal: 0.449
 BlockSizeInMW: 10.0
 InstalledPowerInMW: 30.

- Type: ConventionalTrader

Id: 1004

Attributes:

minMarkup: 100

maxMarkup: 100

Ugandan HFO Plants

- Type: ConventionalPlantOperator

Id: 20

- Type: PredefinedPlantBuilder

Id: 2000

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.6

InstalledPowerInMW: 100.

- Type: ConventionalTrader

Id: 1000

Attributes:

minMarkup: 0

maxMarkup: 0

Kenyan HFO Plants

- Type: ConventionalPlantOperator

Id: 21

- Type: PredefinedPlantBuilder

Id: 2021

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.76

InstalledPowerInMW: 586.32

- Type: ConventionalTrader

Id: 1021

Attributes:

minMarkup: 0

maxMarkup: 0

Rwanda HFO Plant

- Type: ConventionalPlantOperator

Id: 24

- Type: PredefinedPlantBuilder

Id: 2024

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.60

InstalledPowerInMW: 149.8

- Type: ConventionalTrader

Id: 1024

Attributes:

minMarkup: 0

maxMarkup: 0

Kenya Solar

- Type: VariableRenewableOperator

Id: 61

Attributes:

Set: PvFit

EnergyCarrier: PV

SupportInstrument: FIT

InstalledPowerInMW: 251.75

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Kenya Wind

- Type: VariableRenewableOperator

Id: 71

Attributes:

Set: WindOnFit

SupportInstrument: FIT

EnergyCarrier: WindOn

InstalledPowerInMW: 460.5

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Uganda Hydro

- Type: VariableRenewableOperator

Id: 10

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 1757.1

OpexVarInEURperMWH: 55.27

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Kenya Hydro

- Type: VariableRenewableOperator
Id: 11
Attributes:
Set: RunOfRiver
SupportInstrument: FIT
EnergyCarrier: RunOfRiver
InstalledPowerInMW: 859.01
OpexVarInEURperMWH: 26.93141
YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Tanzania Hydro

- Type: VariableRenewableOperator
Id: 12
Attributes:
Set: RunOfRiver
SupportInstrument: FIT
EnergyCarrier: RunOfRiver
InstalledPowerInMW: 2949.31
OpexVarInEURperMWH: 26.93141
YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Ethiopia Hydro

- Type: VariableRenewableOperator
Id: 13
Attributes:
Set: RunOfRiver
SupportInstrument: FIT
EnergyCarrier: RunOfRiver
InstalledPowerInMW: 9830
OpexVarInEURperMWH: 60.32
YieldProfile: "./timeseries/TS_Hydro_Profile_ET.csv"

Rwanda Hydro

- Type: VariableRenewableOperator
Id: 14
Attributes:
Set: RunOfRiver
SupportInstrument: FIT

EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 169.84
 OpexVarInEURperMWH: 26.93141
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Uganda Bioenergy

- Type: Biogas
 Id: 50
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 99.5
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Kenya Bioenergy

- Type: Biogas
 Id: 51
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 39.44
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Ethiopia Bioenergy

- Type: Biogas
 Id: 53
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 111.0
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Rwanda Bioenergy

- Type: Biogas
 Id: 54
 Attributes:
 Set: Biogas

EnergyCarrier: Biogas
 InstalledPowerInMW: 50.0
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "/timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Uganda Solar

- Type: VariableRenewableOperator
 Id: 60
 Attributes:
 Set: PvMpvarCluster1
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 60.0
 OpexVarInEURperMWH: 0.0
 YieldProfile: "/timeseries/TS_Solar_Profile.csv"

Tanzania Solar

- Type: VariableRenewableOperator
 Id: 62
 Attributes:
 Set: PvMpvarCluster3
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 102.5
 OpexVarInEURperMWH: 0.0
 YieldProfile: "/timeseries/TS_Solar_Profile.csv"

Ethiopia Solar

- Type: VariableRenewableOperator
 Id: 63
 Attributes:
 Set: PvMpvarCluster4
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 837.5
 OpexVarInEURperMWH: 0.0
 YieldProfile: "/timeseries/TS_Solar_Profile.csv"

Rwanda Solar

- Type: VariableRenewableOperator
- Id: 64
- Attributes:
 - Set: PvMpvarCluster5
 - EnergyCarrier: PV
 - SupportInstrument: MPVAR
 - InstalledPowerInMW: 12.0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Uganda Wind

- Type: VariableRenewableOperator
- Id: 70
- Attributes:
 - Set: WindOnMpvarCluster1
 - SupportInstrument: MPVAR
 - EnergyCarrier: WindOn
 - InstalledPowerInMW: 10.0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_UG.csv"

Tanzania Wind

- Type: VariableRenewableOperator
- Id: 72
- Attributes:
 - Set: WindOnMpvarCluster3
 - SupportInstrument: MPVAR
 - EnergyCarrier: WindOn
 - InstalledPowerInMW: 50.0
 - OpexVarInEURperMWH: 0.0
 - YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Ethiopia Wind

- Type: VariableRenewableOperator
- Id: 73
- Attributes:
 - Set: WindOnMpvarCluster4
 - SupportInstrument: MPVAR
 - EnergyCarrier: WindOn

InstalledPowerInMW: 1919.0

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_ET.csv"

Contracts: !include ["contracts/*.yaml", "Contracts"]

APPENDIX 11: OPTIMAL RE SCENARIO YAML FILE

AMIRIS scenario for East African day-ahead electricity market in 2025. RW, UG, KE, TZ and ET

OPTIMAL VRE SCENARIO (scenarioOptimalVRE.yaml)

Objective: Maximise VRE capacity while maintaining positive annual mean electricity price

Method: Alpha=0.185 interpolation between Base and High RE scenarios

Result: Mean price = +0.33 EUR/MWh | Total added VRE: +1,109 MW vs Base

Key Ethiopia additions: ET Wind 914 MW (+590 vs Base 324), ET Solar 310 MW (new)

Price constraint: $0.0683 * W + 0.0867 * S \leq 67.5$ EUR/MWh budget

Latest version at: <https://gitlab.com/dlr-ve/esy/amiris/examples/>

Built for AMIRIS version: see project README at: ../README.md

Schema: !include "schema.yaml"

GeneralProperties:

RunId: 3

Simulation:

StartTime: 2024-12-30_23:58:00

StopTime: 2025-12-31_23:58:00

RandomSeed: 1

Output:

Interval: 100

Process: 0

Variables:

- &portfolioBuildingOffset 60

Agents:

- Type: DayAheadMarketSingleZone

Id: 1

Attributes:

Clearing:

DistributionMethod: SAME_SHARES

GateClosureInfoOffsetInSeconds: 11

- Type: CarbonMarket

Id: 3

Attributes:

OperationMode: FIXED

Co2Prices: "./timeseries/TS_CO2_Price.csv"

Sources:

LIGNITE and NUCLEAR are own estimates.

Fuel costs <https://www.bmwi.de/Redaktion/DE/Artikel/Energie/energiedaten-gesamtausgabe.html>, Table 26

Transportation costs

https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strommaerkten.pdf?__blob=publicationFile&v=18, p. 163

- Type: FuelsMarket

Id: 4

Attributes:

FuelPrices:

- FuelType: NUCLEAR

Price: 2.00

ConversionFactor: 1.0

- FuelType: LIGNITE

Price: 35.080616

Factoring in the cost of Geothermal

ConversionFactor: 1.0

- FuelType: HARD_COAL

Price: 0

ConversionFactor: 1.0

- FuelType: NATURAL_GAS

Price: "./timeseries/TS_Natural_Gas_Cost.csv"

ConversionFactor: 1.0

- FuelType: OIL

Price: "/timeseries/TS_Oil_HFO_Cost.csv"

ConversionFactor: 1.0

- Type: DemandTrader

Id: 100

Attributes:

Loads:

- ValueOfLostLoad: 1500.0

DemandSeries: "/timeseries/TS_Demand_EA.csv"

- Type: MeritOrderForecaster

Id: 6

Attributes:

Clearing:

DistributionMethod: SAME_SHARES

ForecastPeriodInHours: 168

ForecastRequestOffsetInSeconds: 27

- Type: StorageTrader #Pumped Hydro Used to represent Battery

Id: 81

Attributes:

ElectricityForecastRequestOffsetInSeconds: 22

Device:

EnergyToPowerRatio: 5.0

SelfDischargeRatePerHour: 0.0

ChargingEfficiency: 0.89

DischargingEfficiency: 0.89

InitialEnergyLevelInMWH: 231

InstalledPowerInMW: 46.25

Strategy:

StrategistType: SINGLE_AGENT_MIN_SYSTEM_COST

ForecastPeriodInHours: 168

ScheduleDurationInHours: 24

SingleAgent:

ModelledChargingSteps: 50

- Type: RenewableTrader

Id: 91

Attributes:

ShareOfRevenues: 0.0

- Type: NoSupportTrader

Id: 92

Attributes:

ShareOfRevenues: 0.0

- Type: SystemOperatorTrader

Id: 3093

- Type: SystemOperatorTrader

Id: 3094

- Type: SystemOperatorTrader

Id: 3095

- Type: SystemOperatorTrader

Id: 3096

- Type: SystemOperatorTrader

Id: 3097

- Type: SystemOperatorTrader

Id: 3098

- Type: SystemOperatorTrader

Id: 3099

- Type: SupportPolicy

Id: 90

Attributes:

SetSupportData:

- Set: PvFit

FIT:

TsFit: 112.982485

- Set: WindOnFit

FIT:

TsFit: 92.009872

- Set: RunOfRiver

FIT:

TsFit: 60.32

- Set: PvMpvarCluster1

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster3

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster4

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster5

MPVAR:

Lcoe: 50.22

- Set: WindOnMpvarCluster1

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster3

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster4

MPVAR:

Lcoe: 61.38

Kenyan Geothermal Plants

- Type: ConventionalPlantOperator

Id: 41

- Type: PredefinedPlantBuilder

Id: 2001

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 35

InstalledPowerInMW: 1025.

- Type: ConventionalTrader

Id: 1001

Attributes:

minMarkup: -60

maxMarkup: 0

Tanzania Geothermal Plant

- Type: ConventionalPlantOperator

Id: 42

- Type: PredefinedPlantBuilder

Id: 2002

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 31.67

InstalledPowerInMW: 17.57

- Type: ConventionalTrader

Id: 1002

Attributes:

minMarkup: -60

maxMarkup: 0

Ethiopia Geothermal Plant

- Type: ConventionalPlantOperator

Id: 43

- Type: PredefinedPlantBuilder

Id: 2003

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 34

InstalledPowerInMW: 38.35

- Type: ConventionalTrader

Id: 1003

Attributes:

minMarkup: -60

maxMarkup: 0

Tanzanian LNG Plants

- Type: ConventionalPlantOperator

Id: 32

- Type: PredefinedPlantBuilder

Id: 2032

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype: #Confirm Tanzania LNG prices/MWh

FuelType: NATURAL_GAS #gasTurbine

SpecificCo2EmissionsInTperMWH: 0.201

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.97

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.327

Maximal: 0.449

BlockSizeInMW: 105.17

InstalledPowerInMW: 1017.5

- Type: ConventionalTrader

Id: 1032

Attributes:

minMarkup: 100

maxMarkup: 100

Rwanda Methane Plant

- Type: ConventionalPlantOperator

Id: 34

- Type: PredefinedPlantBuilder

Id: 2004

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: NATURAL_GAS #gasTurbine

SpecificCo2EmissionsInTperMWH: 0.201

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.97

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.327

Maximal: 0.449

BlockSizeInMW: 10.0

InstalledPowerInMW: 30.

- Type: ConventionalTrader

Id: 1004

Attributes:

minMarkup: 100

maxMarkup: 100

Ugandan HFO Plants

- Type: ConventionalPlantOperator

Id: 20

- Type: PredefinedPlantBuilder

Id: 2000

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.6

InstalledPowerInMW: 100.

- Type: ConventionalTrader

Id: 1000

Attributes:

minMarkup: 0

maxMarkup: 0

Kenyan HFO Plants

- Type: ConventionalPlantOperator

Id: 21

- Type: PredefinedPlantBuilder

Id: 2021

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.76

InstalledPowerInMW: 586.32

- Type: ConventionalTrader

Id: 1021

Attributes:

minMarkup: 0

maxMarkup: 0

Rwanda HFO Plant

- Type: ConventionalPlantOperator

Id: 24

- Type: PredefinedPlantBuilder

Id: 2024

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.60

InstalledPowerInMW: 149.8

- Type: ConventionalTrader

Id: 1024

Attributes:

minMarkup: 0

maxMarkup: 0

Kenya Solar

- Type: VariableRenewableOperator

Id: 61

Attributes:

Set: PvFit

EnergyCarrier: PV

SupportInstrument: FIT

InstalledPowerInMW: 251.75

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Kenya Wind

- Type: VariableRenewableOperator

Id: 71

Attributes:

Set: WindOnFit

SupportInstrument: FIT

EnergyCarrier: WindOn

InstalledPowerInMW: 444.75

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Uganda Hydro

- Type: VariableRenewableOperator

Id: 10

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 1757.1

OpexVarInEURperMWH: 55.27

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Kenya Hydro

- Type: VariableRenewableOperator

Id: 11

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 859.01

OpexVarInEURperMWH: 26.93141

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Tanzania Hydro

- Type: VariableRenewableOperator

Id: 12

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 2836.34

OpexVarInEURperMWH: 26.93141

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Ethiopia Hydro

- Type: VariableRenewableOperator

Id: 13

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 9830

OpexVarInEURperMWH: 60.32

YieldProfile: "./timeseries/TS_Hydro_Profile_ET.csv"

Rwanda Hydro

- Type: VariableRenewableOperator

Id: 14

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 169.84

OpexVarInEURperMWH: 26.93141

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Uganda Bioenergy

- Type: Biogas

Id: 50

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 91.62

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Kenya Bioenergy

- Type: Biogas

Id: 51

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 39.44

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Ethiopia Bioenergy

- Type: Biogas

Id: 53

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 95.25

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Rwanda Bioenergy

- Type: Biogas

Id: 54

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 50.0

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Uganda Solar

- Type: VariableRenewableOperator

Id: 60

Attributes:

Set: PvMpvarCluster1

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 53.7

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Tanzania Solar

- Type: VariableRenewableOperator

Id: 62

Attributes:

Set: PvMpvarCluster3

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 37.92

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Ethiopia Solar

- Type: VariableRenewableOperator

Id: 63

Attributes:

Set: PvMpvarCluster4

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 309.88

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Rwanda Solar

- Type: VariableRenewableOperator

Id: 64

Attributes:

Set: PvMpvarCluster5

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 12.0

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Uganda Wind

- Type: VariableRenewableOperator

Id: 70

Attributes:

Set: WindOnMpvarCluster1

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 3.7

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_UG.csv"

Tanzania Wind

- Type: VariableRenewableOperator

Id: 72

Attributes:

Set: WindOnMpvarCluster3

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 18.5

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Ethiopia Wind

- Type: VariableRenewableOperator

Id: 73

Attributes:

Set: WindOnMpvarCluster4

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 914.15

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_ET.csv"

Contracts: !include ["contracts/*.yaml", "Contracts"]PPENDIX 11: OPTIMAL RE
SCENARIO YAML FILE

APPENDIX 12: GEOTHERMAL MUST-RUN RE SCENARIO YAML FILE

AMIRIS scenario for East African day-ahead electricity market in 2025. RW, UG, KE, TZ and ET

Modelling done based on powerplants expected to be operational by 2025, high renewable scenario- Geothermal must run

Latest version at: <https://gitlab.com/dlr-ve/esy/amiris/examples/>

Built for AMIRIS version: see project README at: ../README.md

Schema: !include "schema.yaml"

GeneralProperties:

RunId: 1

Simulation:

StartTime: 2024-12-30_23:58:00

StopTime: 2025-12-31_23:58:00

RandomSeed: 1

Output:

Interval: 100

Process: 0

Variables:

- &portfolioBuildingOffset 60

Agents:

- Type: DayAheadMarketSingleZone

Id: 1

Attributes:

Clearing:

DistributionMethod: SAME_SHARES

GateClosureInfoOffsetInSeconds: 11

- Type: CarbonMarket

Id: 3

Attributes:

OperationMode: FIXED

Co2Prices: "./timeseries/TS_CO2_Price.csv"

Sources:

LIGNITE and NUCLEAR are own estimates.

Fuel costs <https://www.bmwi.de/Redaktion/DE/Artikel/Energie/energie-daten-gesamtausgabe.html>, Table 26

Transportation costs

https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strommaerkten.pdf?__blob=publicationFile&v=18, p. 163

- Type: FuelsMarket

Id: 4

Attributes:

FuelPrices:

- FuelType: NUCLEAR

Price: 2.00

ConversionFactor: 1.0

- FuelType: LIGNITE

Price: 35.080616 # Factoring in the cost of Geothermal

ConversionFactor: 1.0

- FuelType: HARD_COAL

Price: 0

ConversionFactor: 1.0

- FuelType: NATURAL_GAS

Price: "./timeseries/TS_Natural_Gas_Cost.csv"

ConversionFactor: 1.0

- FuelType: OIL

Price: "./timeseries/TS_Oil_HFO_Cost.csv"

ConversionFactor: 1.0

- Type: DemandTrader

Id: 100

Attributes:

Loads:

- ValueOfLostLoad: 1500.0

DemandSeries: "./timeseries/TS_Demand_EA.csv"

- Type: MeritOrderForecaster

Id: 6

Attributes:

Clearing:

DistributionMethod: SAME_SHARES

ForecastPeriodInHours: 168

ForecastRequestOffsetInSeconds: 27

- Type: StorageTrader #Pumped Hydro Used to represent Battery

Id: 81

Attributes:

ElectricityForecastRequestOffsetInSeconds: 22

Device:

EnergyToPowerRatio: 5.0

SelfDischargeRatePerHour: 0.0

ChargingEfficiency: 0.89

DischargingEfficiency: 0.89

InitialEnergyLevelInMWH: 1000

InstalledPowerInMW: 250

Strategy:

StrategistType: SINGLE_AGENT_MIN_SYSTEM_COST

ForecastPeriodInHours: 168

ScheduleDurationInHours: 24

SingleAgent:

ModelledChargingSteps: 50

- Type: RenewableTrader

Id: 91

Attributes:

ShareOfRevenues: 0.0

- Type: NoSupportTrader

Id: 92

Attributes:

ShareOfRevenues: 0.0

- Type: SystemOperatorTrader

Id: 3093

- Type: SystemOperatorTrader

Id: 3094

- Type: SystemOperatorTrader

Id: 3095

- Type: SystemOperatorTrader

Id: 3096

- Type: SystemOperatorTrader

Id: 3097

- Type: SystemOperatorTrader

Id: 3098

- Type: SystemOperatorTrader

Id: 3099

- Type: SupportPolicy

Id: 90

Attributes:

SetSupportData:

- Set: PvFit

FIT:

TsFit: 112.982485

- Set: WindOnFit

FIT:

TsFit: 92.009872

- Set: RunOfRiver

FIT:

TsFit: 60.32

- Set: PvMpvarCluster1

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster3

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster4

MPVAR:

Lcoe: 50.22

- Set: PvMpvarCluster5

MPVAR:

Lcoe: 50.22

- Set: WindOnMpvarCluster1

MPVAR:

Lcoe: 70.58

- Set: WindOnMpvarCluster3

MPVAR:

Lcoe: 61.38

- Set: WindOnMpvarCluster4

MPVAR:

Lcoe: 61.38

Kenyan Geothermal Plants

MUST-RUN CONSTRAINT: minMarkup/maxMarkup set so that bid price (MC + markup) falls

below the market price floor (-500 EUR/MWh) at all times, guaranteeing dispatch

regardless of market clearing price. MC range = 79.96–114.87 EUR/MWh (LIGNITE proxy).

Bid range with these markups: -540.0 to -385.1 EUR/MWh → always below floor.

- Type: ConventionalPlantOperator

Id: 41

- Type: PredefinedPlantBuilder

Id: 2001

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 35

InstalledPowerInMW: 1025.

- Type: ConventionalTrader

Id: 1001

Attributes:

minMarkup: -620 # Must-run: $\text{bid} = \text{MC} + \text{markup} < -500$ (floor) at all times

maxMarkup: -500 # Must-run: ensures dispatch regardless of market price

Tanzania Geothermal Plant

MUST-RUN CONSTRAINT: same logic as KE geothermal above.

- Type: ConventionalPlantOperator

Id: 42

- Type: PredefinedPlantBuilder

Id: 2002

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 31.67

InstalledPowerInMW: 95.

- Type: ConventionalTrader

Id: 1002

Attributes:

minMarkup: -620 # Must-run: $\text{bid} = \text{MC} + \text{markup} < -500$ (floor) at all times

maxMarkup: -500 # Must-run: ensures dispatch regardless of market price

Ethiopia Geothermal Plant

MUST-RUN CONSTRAINT: same logic as KE geothermal above.

- Type: ConventionalPlantOperator

Id: 43

- Type: PredefinedPlantBuilder

Id: 2003

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 2.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 34

InstalledPowerInMW: 207.3

- Type: ConventionalTrader

Id: 1003

Attributes:

minMarkup: -620 # Must-run: $\text{bid} = \text{MC} + \text{markup} < -500$ (floor) at all times

maxMarkup: -500 # Must-run: ensures dispatch regardless of market price

Tanzanian LNG Plants

- Type: ConventionalPlantOperator

- Id: 32

- Type: PredefinedPlantBuilder

- Id: 2032

- Attributes:

- PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

- Prototype: #Confirm Tanzania LNG prices/MWh

- FuelType: NATURAL_GAS #gasTurbine

- SpecificCo2EmissionsInTperMWH: 0.201

- PlannedAvailability: 1.0

- UnplannedAvailabilityFactor: 0.97

- OpexVarInEURperMWH: 1.2

- CyclingCostInEURperMW: 0.0

- Efficiency:

- Minimal: 0.327

- Maximal: 0.449

- BlockSizeInMW: 105.17

- InstalledPowerInMW: 1262.

- Type: ConventionalTrader

- Id: 1032

- Attributes:

- minMarkup: 100

- maxMarkup: 100

Rwanda Methane Plant

- Type: ConventionalPlantOperator

- Id: 34

- Type: PredefinedPlantBuilder

Id: 2004

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: NATURAL_GAS #gasTurbine

SpecificCo2EmissionsInTperMWH: 0.201

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.97

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.327

Maximal: 0.449

BlockSizeInMW: 10.0

InstalledPowerInMW: 30.

- Type: ConventionalTrader

Id: 1004

Attributes:

minMarkup: 100

maxMarkup: 100

Kenyan HFO Plants

- Type: ConventionalPlantOperator

Id: 21

- Type: PredefinedPlantBuilder

Id: 2021

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.76

InstalledPowerInMW: 586.32

- Type: ConventionalTrader

Id: 1021

Attributes:

minMarkup: 0

maxMarkup: 0

Ugandan HFO Plants

- Type: ConventionalPlantOperator

Id: 20

- Type: PredefinedPlantBuilder

Id: 2000

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.6

InstalledPowerInMW: 100.

- Type: ConventionalTrader

Id: 1000

Attributes:

minMarkup: 0

maxMarkup: 0

Rwanda HFO Plant

- Type: ConventionalPlantOperator

Id: 24

- Type: PredefinedPlantBuilder

Id: 2024

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.60

InstalledPowerInMW: 149.8

- Type: ConventionalTrader

Id: 1024

Attributes:

minMarkup: 0

maxMarkup: 0

Kenya Solar

- Type: VariableRenewableOperator

Id: 61

Attributes:

Set: PvFit

EnergyCarrier: PV

SupportInstrument: FIT

InstalledPowerInMW: 251.75

OpexVarInEURperMWH: 0.0

YieldProfile: "../timeseries/TS_Solar_Profile.csv"

Kenya Wind

- Type: VariableRenewableOperator

Id: 71

Attributes:

Set: WindOnFit

SupportInstrument: FIT

EnergyCarrier: WindOn

InstalledPowerInMW: 485.5 # Consider taking out Ngong wind to Lcoe

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Uganda Hydro

- Type: VariableRenewableOperator

Id: 10

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 1757.1

OpexVarInEURperMWH: 55.27

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Kenya Hydro

- Type: VariableRenewableOperator

Id: 11

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 859.01

OpexVarInEURperMWH: 26.93141

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Tanzania Hydro

- Type: VariableRenewableOperator

Id: 12

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 3128.61

OpexVarInEURperMWH: 55.27

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Ethiopia Hydro

- Type: VariableRenewableOperator

Id: 13

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 9830

OpexVarInEURperMWH: 60.32

YieldProfile: "./timeseries/TS_Hydro_Profile_ET.csv"

Rwanda Hydro

- Type: VariableRenewableOperator

Id: 14

Attributes:

Set: RunOfRiver

SupportInstrument: FIT

EnergyCarrier: RunOfRiver

InstalledPowerInMW: 169.84

OpexVarInEURperMWH: 26.93141

YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Uganda Bioenergy

- Type: Biogas

Id: 50

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 112.

OpexVarInEURperMWH: 0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Kenya Bioenergy

- Type: Biogas

Id: 51

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 39.44

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Ethiopia Bioenergy

- Type: Biogas

Id: 53

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 136.

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Rwanda Bioenergy

- Type: Biogas

Id: 54

Attributes:

Set: Biogas

EnergyCarrier: Biogas

InstalledPowerInMW: 50.

OpexVarInEURperMWH: 0.0

DispatchTimeSeries: "/timeseries/TS_BioEnergy_Profile.csv"

OperationMode: FROM_FILE

Uganda Solar

- Type: VariableRenewableOperator

Id: 60

Attributes:

Set: PvMpvarCluster1

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 70.

OpexVarInEURperMWH: 0.0

YieldProfile: "/timeseries/TS_Solar_Profile.csv"

Tanzania Solar

- Type: VariableRenewableOperator

Id: 62

Attributes:

Set: PvMpvarCluster3

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 205

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Ethiopia Solar

- Type: VariableRenewableOperator

Id: 63

Attributes:

Set: PvMpvarCluster4

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 1675.

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Rwanda Solar

- Type: VariableRenewableOperator

Id: 64

Attributes:

Set: PvMpvarCluster5

EnergyCarrier: PV

SupportInstrument: MPVAR

InstalledPowerInMW: 12.

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Uganda Wind

- Type: VariableRenewableOperator

Id: 70

Attributes:

Set: WindOnMpvarCluster1

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 20

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_UG.csv"

Tanzania Wind

- Type: VariableRenewableOperator

Id: 72

Attributes:

Set: WindOnMpvarCluster3

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 100.0

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile.csv"

Ethiopia Wind

- Type: VariableRenewableOperator

Id: 73

Attributes:

Set: WindOnMpvarCluster4

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 3514

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Onshore_Profile_ET.csv"

Contracts: !include ["contracts/*.yaml", "Contracts"]

APPENDIX 13: KENYA 2023 SCENARIO YAML FILE

```
# AMIRIS scenario for Kenya in year 2023. All existing Power plants in merit order modelled
# Latest version at: https://gitlab.com/dlr-ve/esy/amiris/examples/
# Built for AMIRIS version: see project README at: ../README.md
```

```
Schema: !include "schema.yaml"
```

GeneralProperties:

```
RunId: 1
Simulation:
  StartTime: 2022-12-31_23:58:00
  StopTime: 2023-12-31_23:58:00
  RandomSeed: 1
Output:
  Interval: 100
  Process: 0
```

Variables:

```
- &portfolioBuildingOffset 60
```

Agents:

```
- Type: DayAheadMarketSingleZone
  Id: 1
  Attributes:
    Clearing:
      DistributionMethod: SAME_SHARES
      GateClosureInfoOffsetInSeconds: 11

- Type: CarbonMarket
  Id: 3
  Attributes:
    OperationMode: FIXED
    Co2Prices: "../timeseries/TS_CO2_Price.csv"
```

Sources:

```
# LIGNITE and NUCLEAR are own estimates.
# Fuel costs https://www.bmwi.de/Redaktion/DE/Artikel/Energie/energiedaten-gesamtausgabe.html, Table 26
# Transportation costs
https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/definition-und-monitoring-der-versorgungssicherheit-an-den-europaeischen-strommaerkten.pdf?\_\_blob=publicationFile&v=18, p. 163
```

- Type: FuelsMarket
 - Id: 4
 - Attributes:
 - FuelPrices:
 - FuelType: NUCLEAR
 - Price: 2.00
 - ConversionFactor: 1.0
 - FuelType: LIGNITE
 - Price: 35.080616 # Factoring in the cost of Geothermal
 - ConversionFactor: 1.0
 - FuelType: HARD_COAL
 - Price: 0
 - ConversionFactor: 1.0
 - FuelType: NATURAL_GAS
 - Price: 0
 - ConversionFactor: 1.0
 - FuelType: OIL
 - Price: "./timeseries/TS_HFO_Cost.csv"
 - ConversionFactor: 1.0
- Type: DemandTrader
 - Id: 100
 - Attributes:
 - Loads:
 - ValueOfLostLoad: 1500.0
 - DemandSeries: "./timeseries/Demand_Kenya_2023.csv"
- Type: MeritOrderForecaster
 - Id: 6
 - Attributes:
 - Clearing:
 - DistributionMethod: SAME_SHARES
 - ForecastPeriodInHours: 168
 - ForecastRequestOffsetInSeconds: 27
- Type: StorageTrader #Pumped Hydro Used to represent Battery
 - Id: 7
 - Attributes:
 - ElectricityForecastRequestOffsetInSeconds: 22
 - Device:
 - EnergyToPowerRatio: 5.0
 - SelfDischargeRatePerHour: 0.0
 - ChargingEfficiency: 0.89

DischargingEfficiency: 0.89
 InitialEnergyLevelInMWH: 0
 InstalledPowerInMW: 0
 Strategy:
 StrategistType: SINGLE_AGENT_MIN_SYSTEM_COST
 ForecastPeriodInHours: 168
 ScheduleDurationInHours: 24
 SingleAgent:
 ModelledChargingSteps: 50

- Type: RenewableTrader

Id: 91

Attributes:

 ShareOfRevenues: 0.0

- Type: NoSupportTrader

Id: 92

Attributes:

 ShareOfRevenues: 0.0

- Type: SystemOperatorTrader

Id: 93

- Type: SupportPolicy

Id: 90

Attributes:

 SetSupportData:

 - Set: PvFit

 FIT:

 TsFit: 112.982485

 - Set: WindOnFit

 FIT:

 TsFit: 92.009872

 - Set: RunOfRiver

 FIT:

 TsFit: 26.93141

 - Set: PvMpvarCluster1

 MPVAR:

 Lcoe: 50.22

 - Set: WindOnMpvarCluster1

 MPVAR:

 Lcoe: 61.38

Orpower 4 Geothermal Plant

- Type: ConventionalPlantOperator
Id: 20

- Type: PredefinedPlantBuilder
Id: 2000

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 37.5

InstalledPowerInMW: 150.0

- Type: ConventionalTrader
Id: 1000

Attributes:

minMarkup: -60

maxMarkup: 0

Sosian Geothermal Plant

- Type: ConventionalPlantOperator
Id: 21

- Type: PredefinedPlantBuilder
Id: 2021

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.3108
 Maximal: 0.45
 BlockSizeInMW: 11.67
 InstalledPowerInMW: 35.0

- Type: ConventionalTrader
- Id: 1021
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Olkaria 2 Geothermal Plant

- Type: ConventionalPlantOperator
- Id: 22
- Type: PredefinedPlantBuilder
- Id: 2022
- Attributes:
 - PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 - Prototype:
 - FuelType: LIGNITE # to be replaced with geothermal
 - SpecificCo2EmissionsInTperMWH: 0.0
 - PlannedAvailability: 1.0
 - UnplannedAvailabilityFactor: 0.98
 - OpexVarInEURperMWH: 0.0
 - CyclingCostInEURperMW: 0.0
 - Efficiency:
 - Minimal: 0.3108
 - Maximal: 0.45
 - BlockSizeInMW: 35
 - InstalledPowerInMW: 105.0
- Type: ConventionalTrader
- Id: 1022
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Olkaria 1 unit 6 Geothermal Plants

- Type: ConventionalPlantOperator
Id: 23

- Type: PredefinedPlantBuilder
Id: 2023

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 27.77

InstalledPowerInMW: 83.3

- Type: ConventionalTrader
Id: 1023

Attributes:

minMarkup: -60

maxMarkup: 0

Olkaria 5 Geothermal Plants

- Type: ConventionalPlantOperator
Id: 24

- Type: PredefinedPlantBuilder
Id: 2024

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108
 Maximal: 0.45
 BlockSizeInMW: 33.08
 InstalledPowerInMW: 165.4

- Type: ConventionalTrader
 Id: 1024
 Attributes:
 minMarkup: -60
 maxMarkup: 0

Olkaria 1 AU Geothermal Plants

- Type: ConventionalPlantOperator
 Id: 25
- Type: PredefinedPlantBuilder
 Id: 2025
 Attributes:
 PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 Prototype:
 FuelType: LIGNITE # to be replaced with geothermal
 SpecificCo2EmissionsInTperMWH: 0.0
 PlannedAvailability: 1.0
 UnplannedAvailabilityFactor: 0.98
 OpexVarInEURperMWH: 0.0
 CyclingCostInEURperMW: 0.0
 Efficiency:
 Minimal: 0.3108
 Maximal: 0.45
 BlockSizeInMW: 37.5
 InstalledPowerInMW: 150
- Type: ConventionalTrader
 Id: 1025
 Attributes:
 minMarkup: -60
 maxMarkup: 0

Olkaria 4 Geothermal Plants

- Type: ConventionalPlantOperator
 Id: 26

- Type: PredefinedPlantBuilder

Id: 2026

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 37.5

InstalledPowerInMW: 150

- Type: ConventionalTrader

Id: 1026

Attributes:

minMarkup: -60

maxMarkup: 0

Wellheads 1 Geothermal Plants

- Type: ConventionalPlantOperator

Id: 27

- Type: PredefinedPlantBuilder

Id: 2027

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: LIGNITE # to be replaced with geothermal

SpecificCo2EmissionsInTperMWH: 0.0

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.98

OpexVarInEURperMWH: 0.0

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.3108

Maximal: 0.45

BlockSizeInMW: 16.22
 InstalledPowerInMW: 81.1

- Type: ConventionalTrader
- Id: 1027
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

Wellheads Olkaria & Eburru Geothermal Plants

- Type: ConventionalPlantOperator
- Id: 28
- Type: PredefinedPlantBuilder
- Id: 2028
- Attributes:
 - PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset
 - Prototype:
 - FuelType: LIGNITE # to be replaced with geothermal
 - SpecificCo2EmissionsInTperMWH: 0.0
 - PlannedAvailability: 1.0
 - UnplannedAvailabilityFactor: 0.98
 - OpexVarInEURperMWH: 0.0
 - CyclingCostInEURperMW: 0.0
 - Efficiency:
 - Minimal: 0.3108
 - Maximal: 0.45
 - BlockSizeInMW: 7.4
 - InstalledPowerInMW: 7.4

- Type: ConventionalTrader
- Id: 1028
- Attributes:
 - minMarkup: -60
 - maxMarkup: 0

IberAfrica HFO Plants

- Type: ConventionalPlantOperator
- Id: 40
- Type: PredefinedPlantBuilder

Id: 2040

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.5

InstalledPowerInMW: 52.5

- Type: ConventionalTrader

Id: 1040

Attributes:

minMarkup: 0

maxMarkup: 0

Thika Power HFO Plant

- Type: ConventionalPlantOperator

Id: 41

- Type: PredefinedPlantBuilder

Id: 2041

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.4

InstalledPowerInMW: 87

- Type: ConventionalTrader

Id: 1041

Attributes:

minMarkup: 0

maxMarkup: 0

Rabai Power HFO Plant

- Type: ConventionalPlantOperator

Id: 42

- Type: PredefinedPlantBuilder

Id: 2042

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 18

InstalledPowerInMW: 90

- Type: ConventionalTrader

Id: 1042

Attributes:

minMarkup: 0

maxMarkup: 0

Gulf Power HFO Plant

- Type: ConventionalPlantOperator

Id: 43

- Type: PredefinedPlantBuilder

Id: 2043

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.06

InstalledPowerInMW: 80.32

- Type: ConventionalTrader

Id: 1043

Attributes:

minMarkup: 0

maxMarkup: 0

Triumph Power HFO Plant

- Type: ConventionalPlantOperator

Id: 44

- Type: PredefinedPlantBuilder

Id: 2044

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 16.60

InstalledPowerInMW: 83

- Type: ConventionalTrader

Id: 1044

Attributes:

minMarkup: 0

maxMarkup: 0

Kipevu 3 HFO Plant

- Type: ConventionalPlantOperator

Id: 45

- Type: PredefinedPlantBuilder

Id: 2045

Attributes:

PortfolioBuildingOffsetInSeconds: *portfolioBuildingOffset

Prototype:

FuelType: OIL # oil, other fossil fuels, mixed fossil fuels

SpecificCo2EmissionsInTperMWH: 0.264

PlannedAvailability: 1.0

UnplannedAvailabilityFactor: 0.93

OpexVarInEURperMWH: 1.2

CyclingCostInEURperMW: 0.0

Efficiency:

Minimal: 0.311

Maximal: 0.397

BlockSizeInMW: 17.14

InstalledPowerInMW: 120

- Type: ConventionalTrader

Id: 1045

Attributes:

minMarkup: 0

maxMarkup: 0

Selenkei Solar

- Type: VariableRenewableOperator

Id: 50

Attributes:

Set: PvFit

EnergyCarrier: PV

SupportInstrument: FIT

InstalledPowerInMW: 40

OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Cedate Solar

- Type: VariableRenewableOperator
 Id: 51
 Attributes:
 Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 40
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Malindi Solar

- Type: VariableRenewableOperator
 Id: 52
 Attributes:
 Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 40
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Alten Solar

- Type: VariableRenewableOperator
 Id: 53
 Attributes:
 Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 40
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Marco Borero Solar

- Type: VariableRenewableOperator
 Id: 55

Attributes:

Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 1.5
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Strathmore Solar

- Type: VariableRenewableOperator

Id: 54

Attributes:

Set: PvFit
 EnergyCarrier: PV
 SupportInstrument: FIT
 InstalledPowerInMW: 0.25
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

Lake Turkana Wind

- Type: VariableRenewableOperator

Id: 60

Attributes:

Set: WindOnFit
 SupportInstrument: FIT
 EnergyCarrier: WindOn
 InstalledPowerInMW: 310
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Wind_LTWP.csv"

Kipeto Wind

- Type: VariableRenewableOperator

Id: 61

Attributes:

Set: WindOnFit
 SupportInstrument: FIT
 EnergyCarrier: WindOn
 InstalledPowerInMW: 100
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Wind_Kip_Ng.csv"

Private Small Hydros

- Type: VariableRenewableOperator
 Id: 70
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 24.38
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

KenGen Large Hydros

- Type: VariableRenewableOperator
 Id: 71
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 765.20
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Sangoro Hydro

- Type: VariableRenewableOperator
 Id: 72
 Attributes:
 Set: RunOfRiver
 SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 21
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

KenGen Small Hydros

- Type: VariableRenewableOperator
 Id: 73
 Attributes:
 Set: RunOfRiver

SupportInstrument: FIT
 EnergyCarrier: RunOfRiver
 InstalledPowerInMW: 33.73
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Hydro_Profile.csv"

Biojule Power

- Type: Biogas
 Id: 30
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 2
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

REA Vipingo

- Type: Biogas
 Id: 31
 Attributes:
 Set: Biogas
 EnergyCarrier: Biogas
 InstalledPowerInMW: 1.44
 OpexVarInEURperMWH: 0.0
 DispatchTimeSeries: "./timeseries/TS_BioEnergy_Profile.csv"
 OperationMode: FROM_FILE

Garissa Solar

- Type: VariableRenewableOperator
 Id: 56
 Attributes:
 Set: PvMpvarCluster1
 EnergyCarrier: PV
 SupportInstrument: MPVAR
 InstalledPowerInMW: 50.0
 OpexVarInEURperMWH: 0.0
 YieldProfile: "./timeseries/TS_Solar_Profile.csv"

KenGen Wind

- Type: VariableRenewableOperator

Id: 62

Attributes:

Set: WindOnMpvarCluster1

SupportInstrument: MPVAR

EnergyCarrier: WindOn

InstalledPowerInMW: 25.5

OpexVarInEURperMWH: 0.0

YieldProfile: "./timeseries/TS_Wind_Kip_Ng.csv"

Contracts: !include ["contracts/*.yaml", "Contracts"]

APPENDIX 14: CONTRACTS -CONVENTIONALS YAML FILE

AgentGroups:

- &builders [2000, 2021, 2001, 2032, 2004, 2024, 2002, 2003]
- &traders [1000, 1021, 1001, 1032, 1004, 1024, 1002, 1003]
- &operators [20, 21, 41, 32, 34, 24, 42, 43]
- &exchange 1
- &carbonMarket 3
- &fuelsMarket 4
- &forecaster 6

Contracts:

```
#####
```

```
# -- PlantBuildingManagement -- #
```

```
#####
```

- SenderId: *builders
- ReceiverId: *operators
- ProductName: PowerPlantPortfolio
- FirstDeliveryTime: -60
- DeliveryIntervalInSteps: 31536000

```
#####
```

```
# -- Forecast Preparation -- #
```

```
#####
```

- SenderId: *forecaster
- ReceiverId: *traders
- ProductName: ForecastRequest
- FirstDeliveryTime: -26
- DeliveryIntervalInSteps: 3600

- SenderId: *traders
- ReceiverId: *operators
- ProductName: ForecastRequestForward
- FirstDeliveryTime: -25
- DeliveryIntervalInSteps: 3600

- SenderId: *operators
- ReceiverId: *fuelsMarket
- ProductName: FuelPriceForecastRequest
- FirstDeliveryTime: -24
- DeliveryIntervalInSteps: 3600

- SenderId: *operators
- ReceiverId: *carbonMarket
- ProductName: Co2PriceForecastRequest
- FirstDeliveryTime: -24
- DeliveryIntervalInSteps: 3600

```

- SenderId: *fuelsMarket
  ReceiverId: *operators
  ProductName: FuelPriceForecast
  FirstDeliveryTime: -23
  DeliveryIntervalInSteps: 3600

- SenderId: *carbonMarket
  ReceiverId: *operators
  ProductName: Co2PriceForecast
  FirstDeliveryTime: -23
  DeliveryIntervalInSteps: 3600

- SenderId: *operators
  ReceiverId: *traders
  ProductName: MarginalCostForecast
  FirstDeliveryTime: -22
  DeliveryIntervalInSteps: 3600

- SenderId: *traders
  ReceiverId: *forecaster
  ProductName: BidsForecast
  FirstDeliveryTime: -21
  DeliveryIntervalInSteps: 3600

#####
# -- Bidding -- #
#####
- SenderId: *exchange
  ReceiverId: *traders
  ProductName: GateClosureInfo
  FirstDeliveryTime: -10
  DeliveryIntervalInSteps: 3600

- SenderId: *traders
  ReceiverId: *operators
  ProductName: GateClosureForward
  FirstDeliveryTime: -9
  DeliveryIntervalInSteps: 3600

- SenderId: *operators
  ReceiverId: *fuelsMarket
  ProductName: FuelPriceRequest
  FirstDeliveryTime: -3
  DeliveryIntervalInSteps: 3600

- SenderId: *operators

```


ReceiverId: *carbonMarket
 ProductName: Co2PriceRequest
 FirstDeliveryTime: -3
 DeliveryIntervalInSteps: 3600

- SenderId: *fuelsMarket
 ReceiverId: *operators
 ProductName: FuelPrice
 FirstDeliveryTime: -2
 DeliveryIntervalInSteps: 3600

- SenderId: *carbonMarket
 ReceiverId: *operators
 ProductName: Co2Price
 FirstDeliveryTime: -2
 DeliveryIntervalInSteps: 3600

- SenderId: *operators
 ReceiverId: *traders
 ProductName: MarginalCost
 FirstDeliveryTime: -1
 DeliveryIntervalInSteps: 3600

- SenderId: *traders
 ReceiverId: *exchange
 ProductName: Bids
 FirstDeliveryTime: 0
 DeliveryIntervalInSteps: 3600

#####

-- Evaluation --

#####

- SenderId: *exchange
 ReceiverId: *traders
 ProductName: Awards
 FirstDeliveryTime: 4
 DeliveryIntervalInSteps: 3600

- SenderId: *traders
 ReceiverId: *operators
 ProductName: DispatchAssignment
 FirstDeliveryTime: 5
 DeliveryIntervalInSteps: 3600

- SenderId: *traders
 ReceiverId: *operators
 ProductName: Payout

FirstDeliveryTime: 6
 DeliveryIntervalInSteps: 3600

APPENDIX 15: CONTRACTS DEMAND YAML FILE

AgentGroups:

- &exchange 1
- &forecaster 6
- &demandTrader 100

Contracts:

- SenderId: *forecaster
 ReceiverId: *demandTrader
 ProductName: ForecastRequest
 FirstDeliveryTime: -26
 DeliveryIntervalInSteps: 3600
- SenderId: *demandTrader
 ReceiverId: *forecaster
 ProductName: BidsForecast
 FirstDeliveryTime: -21
 DeliveryIntervalInSteps: 3600
- SenderId: *exchange
 ReceiverId: *demandTrader
 ProductName: GateClosureInfo
 FirstDeliveryTime: -10
 DeliveryIntervalInSteps: 3600
- SenderId: *demandTrader
 ReceiverId: *exchange
 ProductName: Bids
 FirstDeliveryTime: 0
 DeliveryIntervalInSteps: 3600
- SenderId: *exchange
 ReceiverId: *demandTrader
 ProductName: Awards
 FirstDeliveryTime: 4
 DeliveryIntervalInSteps: 3600

APPENDIX 16: CONTRACTS RENEWABLES NO SUPPORT YAML FILE

AgentGroups:

- &exchange 1
- &forecaster 6
- &marketer 92
- &renewables [50, 51, 53, 54]

Contracts:

```
#####
```

```
# -- Registration --      #
```

```
#####
```

- SenderId: *renewables
- ReceiverId: *marketer
- ProductName: SetRegistration
- FirstDeliveryTime: -37
- DeliveryIntervalInSteps: 31536000

```
#####
```

```
# -- Forecasting --      #
```

```
#####
```

- SenderId: *forecaster
- ReceiverId: *marketer
- ProductName: ForecastRequest
- FirstDeliveryTime: -26
- DeliveryIntervalInSteps: 3600

- SenderId: *marketer
- ReceiverId: *renewables
- ProductName: ForecastRequestForward
- FirstDeliveryTime: -25
- DeliveryIntervalInSteps: 3600

- SenderId: *renewables
- ReceiverId: *marketer
- ProductName: MarginalCostForecast
- FirstDeliveryTime: -22
- DeliveryIntervalInSteps: 3600

- SenderId: *marketer
- ReceiverId: *forecaster
- ProductName: BidsForecast
- FirstDeliveryTime: -21
- DeliveryIntervalInSteps: 3600

```
#####
```

```
# -- Bidding --      #
```

#####

- SenderId: *exchange
ReceiverId: *marketer
ProductName: GateClosureInfo
FirstDeliveryTime: -10
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: GateClosureForward
FirstDeliveryTime: -9
DeliveryIntervalInSteps: 3600
- SenderId: *renewables
ReceiverId: *marketer
ProductName: MarginalCost
FirstDeliveryTime: -1
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *exchange
ProductName: Bids
FirstDeliveryTime: 0
DeliveryIntervalInSteps: 3600

#####

-- Dispatch & Payment --

#####

- SenderId: *exchange
ReceiverId: *marketer
ProductName: Awards
FirstDeliveryTime: 4
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: DispatchAssignment
FirstDeliveryTime: 5
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: Payout
FirstDeliveryTime: 2626204
DeliveryIntervalInSteps: 2628000

APPENDIX 17: CONTRACTS RENEWABLE TRADER YAML FILE

AgentGroups:

- &exchange 1
- &forecaster 6
- &marketer 91
- &renewables [60, 62, 63, 64, 70, 72, 73]

Contracts:

```
#####
```

```
# -- Registration --      #
```

```
#####
```

- SenderId: *renewables
- ReceiverId: *marketer
- ProductName: SetRegistration
- FirstDeliveryTime: -37
- DeliveryIntervalInSteps: 31536000

```
#####
```

```
# -- Forecasting --      #
```

```
#####
```

- SenderId: *forecaster
- ReceiverId: *marketer
- ProductName: ForecastRequest
- FirstDeliveryTime: -26
- DeliveryIntervalInSteps: 3600
- SenderId: *marketer
- ReceiverId: *renewables
- ProductName: ForecastRequestForward
- FirstDeliveryTime: -25
- DeliveryIntervalInSteps: 3600

- SenderId: *renewables
- ReceiverId: *marketer
- ProductName: MarginalCostForecast
- FirstDeliveryTime: -22
- DeliveryIntervalInSteps: 3600

- SenderId: *marketer
- ReceiverId: *forecaster
- ProductName: BidsForecast
- FirstDeliveryTime: -21
- DeliveryIntervalInSteps: 3600

```
#####
```

```
# -- Bidding --      #
```

```
#####
```

- SenderId: *exchange
ReceiverId: *marketer
ProductName: GateClosureInfo
FirstDeliveryTime: -10
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: GateClosureForward
FirstDeliveryTime: -9
DeliveryIntervalInSteps: 3600
- SenderId: *renewables
ReceiverId: *marketer
ProductName: MarginalCost
FirstDeliveryTime: -1
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *exchange
ProductName: Bids
FirstDeliveryTime: 0
DeliveryIntervalInSteps: 3600

```
#####
```

```
# -- Dispatch --      #
```

```
#####
```

- SenderId: *exchange
ReceiverId: *marketer
ProductName: Awards
FirstDeliveryTime: 4
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: DispatchAssignment
FirstDeliveryTime: 5
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: Payout
FirstDeliveryTime: 2626204
DeliveryIntervalInSteps: 2628000

APPENDIX 18: CONTRACTS RENEWABLES SYSTEM OPERATOR YAML FILE

AgentGroups:

- &exchange 1
- &forecaster 6
- &marketer [3093, 3094, 3095, 3096, 3097, 3098, 3099]
- &renewables [10, 11, 12, 13, 14, 61, 71]

Contracts:

#####

-- Registration --

#####

- SenderId: *renewables
- ReceiverId: *marketer
- ProductName: SetRegistration
- FirstDeliveryTime: -37
- DeliveryIntervalInSteps: 31536000

#####

-- Forecasting --

#####

- SenderId: *forecaster
- ReceiverId: *marketer
- ProductName: ForecastRequest
- FirstDeliveryTime: -26
- DeliveryIntervalInSteps: 3600
- SenderId: *marketer
- ReceiverId: *renewables
- ProductName: ForecastRequestForward
- FirstDeliveryTime: -25
- DeliveryIntervalInSteps: 3600
- SenderId: *renewables
- ReceiverId: *marketer
- ProductName: MarginalCostForecast
- FirstDeliveryTime: -22
- DeliveryIntervalInSteps: 3600
- SenderId: *marketer
- ReceiverId: *forecaster
- ProductName: BidsForecast
- FirstDeliveryTime: -21
- DeliveryIntervalInSteps: 3600

#####

-- Bidding --

```
#####
```

- SenderId: *exchange
ReceiverId: *marketer
ProductName: GateClosureInfo
FirstDeliveryTime: -10
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: GateClosureForward
FirstDeliveryTime: -9
DeliveryIntervalInSteps: 3600
- SenderId: *renewables
ReceiverId: *marketer
ProductName: MarginalCost
FirstDeliveryTime: -1
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *exchange
ProductName: Bids
FirstDeliveryTime: 0
DeliveryIntervalInSteps: 3600

```
#####
```

```
# -- Dispatch --      #
```

```
#####
```

- SenderId: *exchange
ReceiverId: *marketer
ProductName: Awards
FirstDeliveryTime: 4
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: DispatchAssignment
FirstDeliveryTime: 5
DeliveryIntervalInSteps: 3600
- SenderId: *marketer
ReceiverId: *renewables
ProductName: Payout
FirstDeliveryTime: 2626204
DeliveryIntervalInSteps: 2628000

APPENDIX 19: CONTRACTS STORAGE YAML FILE

AgentGroups:

- &exchange 1
- &forecaster 6
- &storage 81

Contracts:

#####

-- Forecasting --

#####

- SenderId: *storage
 - ReceiverId: *forecaster
 - ProductName: MeritOrderForecastRequest
 - FirstDeliveryTime: -21
 - DeliveryIntervalInSteps: 3600

- SenderId: *forecaster
 - ReceiverId: *storage
 - ProductName: MeritOrderForecast
 - FirstDeliveryTime: -19
 - DeliveryIntervalInSteps: 3600

#####

-- Bidding --

#####

- SenderId: *exchange
 - ReceiverId: *storage
 - ProductName: GateClosureInfo
 - FirstDeliveryTime: -10
 - DeliveryIntervalInSteps: 3600

- SenderId: *storage
 - ReceiverId: *exchange
 - ProductName: Bids
 - FirstDeliveryTime: 0
 - DeliveryIntervalInSteps: 3600

- SenderId: *exchange
 - ReceiverId: *storage
 - ProductName: Awards
 - FirstDeliveryTime: 4
 - DeliveryIntervalInSteps: 3600

APPENDIX 20: CONTRACTS SUPPORT POLICY YAML FILE**AgentGroups:**

- &exchange 1
- &policy 90
- &allMarketers [91, 92, 3093, 3094, 3095, 3096, 3097, 3098, 3099]
- &supportedMarketers [91, 3093, 3094, 3095, 3096, 3097, 3098, 3099]

Contracts:

- SenderId: *supportedMarketers
ReceiverId: *policy
ProductName: SupportInfoRequest
FirstDeliveryTime: -35
DeliveryIntervalInSteps: 31536000
- SenderId: *policy
ReceiverId: *supportedMarketers
ProductName: SupportInfo
FirstDeliveryTime: -33
DeliveryIntervalInSteps: 31536000
- SenderId: *allMarketers
ReceiverId: *policy
ProductName: YieldPotential
FirstDeliveryTime: 1
DeliveryIntervalInSteps: 3600
- SenderId: *exchange
ReceiverId: *policy
ProductName: Awards
FirstDeliveryTime: 4
DeliveryIntervalInSteps: 3600
- SenderId: *supportedMarketers
ReceiverId: *policy
ProductName: SupportPayoutRequest
FirstDeliveryTime: 2626200
DeliveryIntervalInSteps: 2628000
- SenderId: *policy
ReceiverId: *supportedMarketers
ProductName: SupportPayout
FirstDeliveryTime: 2626202
DeliveryIntervalInSteps: 2628000
- SenderId: *policy
ReceiverId: *policy
ProductName: MarketValueCalculation

FirstDeliveryTime: 2626204
DeliveryIntervalInSteps: 2628000