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The role of geothermal and coal in Kenya's electricity sector and implications for sustainable development

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Summary

Kenya is one of the fastest growing economies in Sub-Saharan Africa, with high anticipated economic growth rates and ambitious flagship infrastructure projects. However, recent electricity demand forecasts were considerably decreased. Both in the scenarios of subdued growth and higher future electricity demand growth, it is key that capacity planning for electricity generation is carried out so that electricity supply matches demand. At the same time, sustainable development-related objectives and environmental targets need to be achieved. This includes Kenya's target to reduce greenhouse gas (GHG) emissions by 30% below business as usual by 2030, as announced in the country's Nationally Determined Contribution (NDC) to the Paris Agreement.

A major challenge for planners and policymakers in the electricity sector is identifying the optimal combination of electricity generation technologies within different load-factor categories in order to achieve the best match at the lowest cost. This study aims at supporting decision making in the electricity sector by comparing the two main power generation technologies that are considered baseload electricity supply options in Kenya, namely, geothermal and coal, and the role that they can play in Kenya's future electricity supply mix. This role is determined by a number of factors, including technical considerations, resource availability, environmental characteristics, economics, and other issues that may act as drivers or pose barriers or risks to the development of this source. Electricity sector planning in Kenya relies on a 20-year rolling masterplan for power supply, the latest being the 2017-2037 Least Cost Power Development Plan (LCPDP), which sets a clear direction for the development of the sector and thus serves as a main reference for this study.

While Kenya has a long history of developing geothermal resources, coal has not yet been exploited. Kenya has a high geothermal resource potential of around 10,000 MW along the Kenyan Rift Valley. The current installed geothermal capacity in Kenya is 745 MW, with most of it in the Olkaria fields. However, the Government of Kenya plans to build two coal power plants over the next 30 years: one in Lamu, a 981 MW power plant divided into three units of 327 MW each, to be commissioned by 2024, and a 960 MW power plant in Kitui, which is scheduled for 2034-36. While the plant in Lamu will run on imported coal, the plant in Kitui is predicted to use domestic coal.

The development of these two generation technologies will have a considerable impact on the electricity sector in Kenya, affecting the generation costs, affordability of electricity, and overall flexibility and reliability of electricity supply.

Generation costs: Various cost aspects must be considered when comparing the cost of geothermal and coal-based electricity generation. Geothermal power typically involves high **capital expenditure** due to a risky exploration and drilling phase. On the other hand, no fuel costs are incurred, and **operation and maintenance costs** are low and predictable. Coal power plants are less costly in the construction phase, but variable operation and maintenance costs can be significant if the coal is imported. The **cost of capital** for a geothermal project in Kenya is low compared to the capital costs for global coal projects. It is likely that financial support for geothermal projects will further increase and be more easily accessible in the future, while coal financing is being gradually taken out of many portfolios. **Legal and regulatory costs** are currently more predictable for geothermal power generation, with the Energy Act 2019 establishing a royalty scheme for geothermal resource use. For coal-based power generation, regulations are still pending and respective costs, difficult to predict. Little data exists on the **decommissioning costs** of geothermal plants, while for coal plants, these costs range from USD 50,000 to 160,000 per MW. Both geothermal and coal have a high **capacity factor** and can produce a stable output at a low price. However, the capacity of a plant can be restricted on purpose to balance supply and demand. The projected capacity factor of a plant determines the **Levelised Cost of Electricity** (LCOE). In the case of Kenya, in the planning period covered by the 2017-2037 LCPDP, the LCOE for geothermal is significantly lower than the one for coal (approx. USD 10 cents/kWh for geothermal vs. USD 29.5 cents/kWh for coal), since coal is expected to run at a very low capacity factor.

Affordability: The addition of more geothermal power generation capacity would have advantages over coal-based generation capacity, both in terms of limiting the overall costs of electricity supply and the retail price

and ensuring cost stability. While the majority of the geothermal generation costs are fixed costs, with the cost of labour being the only significant variable factor, a substantial portion of the coal power generation costs are variable costs for fuel input. When comparing the type of capital expenditure, it is worth noting that coal power is usually characterised by very large capacity additions, causing significant spikes in capital investment costs over time, while geothermal power plants are typically much smaller and can be developed more gradually according to variations in demand. The introduction of a 981 MW coal plant in 2024 may increase the cost of electricity by up to 50% due to the surplus capacity that this large-scale capacity addition would entail for a period of at least several years. Moreover, in the case of surplus capacity, geothermal power generation is identified in the LCPDP as a higher priority option for dispatch, due to its lower marginal costs compared to coal-based power generation. Kenya's electric utility Kenya Power will have to pay for the Lamu coal power plant's output regardless of whether or not the power is actually purchased, due to the nature of the purchase power agreement (PPA). The PPA includes a particularly high capacity charge of USD 360 million per year, which translates to about KES 100 million per day, in a take-or-pay agreement.

Flexibility and reliability: Although geothermal and coal-fired power plants are both considered baseload power plants, geothermal plants can reach higher capacity factors, on average. Although geothermal plants operate most efficiently when running without interruption, similar to coal plants, they can also provide flexible power if contractual terms are modified accordingly. The operation and maintenance costs incurred for a geothermal plant to operate in a more flexible manner depend on the type of technology used. While operating a binary system in a flexible mode does not raise these costs significantly, the flexible operation of a flash or dry steam system may lead to a slight increase, as it involves venting steam. Increasing the flexibility of a coal plant is also technically possible; however, it has an impact on the plant's lifetime and is similarly associated with an increase in operation and maintenance costs. The expansion of geothermal energy in Kenya provides more flexibility to planners, as geothermal power generation is decentralised, and capacity can be added gradually. Given the uncertain sector development, the implementation of a large-scale project like the Lamu plant, on the other hand, might put sector stability, affordability, and sustainability at risk.

Apart from the implications for the sector itself, careful planning in the electricity supply sector can positively contribute to the achievement of other sustainable development-related objectives that are important to society, such as **employment creation**, **health,** and **climate change**.

Investment in electricity generation results in the immediate creation of **direct and indirect employment opportunities,** as well as wider economic effects, during a project's construction and operation phases. A comparison of different generation expansion scenarios, which are based on the 2017-2037 LCPDP, reveals that i) no coal-fired power plant is required in generation expansion planning if sufficient alternative candidates are provided and expansion sequences are optimised for least-cost options; and ii) the scenario without coal, entailing more geothermal energy and natural gas, leads to more domestic employment creation and investment, while simultaneously being less expensive. A direct comparison of both generation technologies with regard to their impact on job creation shows that geothermal power generation creates three times more domestic employment per MW of new capacity than coal-based power generation. The main reason for these results are the different local shares in the value chain for these two technologies. While geothermal power has a long history in Kenya, and expertise is locally available and sourced, coal development would heavily rely on the foreign labour force, both for construction and operation and maintenance of the plant.

Electricity generation technologies also differ in terms of their impact on **air pollution and human health**. The energy sector in general, including both production and use, is the largest source of man-made air pollution emissions. Geothermal and coal-fired power plant emissions differ significantly, not only in terms of GHG emissions, but also other air pollutants such as particulate matter, sulphur dioxide, and nitrogen oxides. Geothermal power plants emit less than 1% of the air pollutants emitted by coal-fired power plants of equal capacity. The construction and operation of the proposed coal-fired power plants in Kenya would be a major source of air pollution in the country, with significant impacts on human health. A quantitative analysis of the health impacts shows that up to 2065, roughly 1,620 Kenyans would have died prematurely from the

associated air pollution if both coal plants in Lamu and Kitui were to be built. For the same timeframe, approximately 270 premature deaths would occur if the capacity of the Lamu plant was reduced to 450 MW in total. These health impacts are further associated with significant costs for the healthcare system.

Apart from these important effects on sustainable development, the plans to develop coal-based power generation in Kenya put the country's **climate target** at risk and create pressure for other sectors to invest in mitigation measures that are often more expensive and difficult to implement. While both geothermal and coal-based power generation result in GHG emissions, the average global estimate for geothermal power production, at 122 gCO_2/kWh, is much lower than the estimate for coal—670-870 gCO_2/kWh. In the case of Kenya, emissions calculations for different generation expansion scenarios show that by 2037, almost 3 $MtCO_2$ could be saved annually if coal were replaced with low-carbon alternatives such as geothermal, complemented by generic backup units. Under the application of a shadow carbon price, the emissions savings could translate to cost savings of USD 160-320 million per year by 2037, depending on the price level.

The findings of this study illustrate the need for electricity sector planners and decision-makers to carefully evaluate the opportunities and risks involved in the expansion of coal-based power generation, as compared to geothermal power generation. Coal-based power generation is not needed from a security of supply perspective, as the extremely low average capacity factors in the 2017-2037 LCPDP indicate, and the further development of geothermal power generation may have positive effects on the power sector, as well as other sectors.

Based on the study's findings, the following aspects can guide the future development of the geothermal sector:

- Considering the power sector requirements and environmental concerns, it is recommended to primarily use **binary steam cycle technology** where possible, as this technology can operate more flexibly without increasing operation and maintenance costs and produces near-zero emissions during operations.
- While it is physically possible for a geothermal power plant to provide a range of ancillary services, traditional PPAs often do not set the right incentives for this. **PPAs need to be adjusted** to ensure that geothermal power plants are compensated, not only for operating as baseload plants, but also for providing reserve capacity.
- As the productivity of geothermal sources can decrease, **site diversification** is essential. Currently, geothermal power is mostly harnessed in the Olkaria fields, and it is estimated that by 2035, half of the geothermal capacity will still be located in this area. Thus, encouraging the development of new geothermal plants in other geothermal fields, such as Suswa, Longonot, Akiira, and Baringo Silali, can reduce site dependency and ensure security of supply.

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Abbreviations

AIRPOLIM-ES	Air Pollution Impact Model for Electricity Supply
BAU	Business as Usual
BMZ	Federal Ministry for Economic Cooperation and Development
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CO₂	Carbon Dioxide
COD	Commercial Operation Date
COPD	Chronic Obstructive Pulmonary Disease
DNA	Deoxyribonucleic Acid
ECN part of TNO	Energy Research Centre of the Netherlands
EIM-ES	Economic Impact Model for Electricity Supply
ESIA	Environmental and Social Impact Assessments
EPRA	Energy and Petroleum Regulatory Authority
EU-Africa ITF	European Union-Africa Infrastructure Trust Fund
FCC	Fuel Cost Charge
FERFA	Foreign Exchange Rate Fluctuation Adjustment
FTE	Full-Time Equivalent
g	gram
GDC	Geothermal Development Company
GE	General Electric
GIS	Geographic Information System
GoK	Government of Kenya
GRMF	Geothermal Risk Mitigation Facility
GWh	Gigawatt hour
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
KenGen	Kenya Electricity Generating Company
KES	Kenyan Shilling
kg	kilogramme
KPLC	Kenya Power and Lighting Company
kWh	Kilowatt hour
LAPSSET Corridor	Lamu Port South Sudan Ethiopia Transport Corridor
LCOE	Levelised Cost of Electricity
LCPDP	Least Cost Power Development Plan
LIPS OP/XP software	Lahmeyer International Short-Term Optimisation and Long-Term Expansion software

MJ	Megajoule
MoE	Ministry of Energy
Mt	Megaton
MW	Megawatt
NCCAP	National Climate Change Action Plan
NDC	Nationally Determined Contribution
NEMA	National Environment Management Authority
NO$_x$	Nitrogen and Nitrous Oxides
O&M	Operation and Maintenance
OECD	Organisation for Economic Co-operation and Development
OPEX	Operations and maintenance expenditure
PGTMP	Power Generation and Transmission Master Plan
PPA	Purchase Power Agreement
SGR	Standard Gauge Railway
SO$_2$	Sulphur Dioxide
Solar PV	Solar Photovoltaic
t	tonne
TJ	Terajoule
USD	United States Dollar
VAT	Value Added Tax
WACC	Weighted Average Cost of Capital

1 Introduction

Kenya is one of the fastest growing economies in Sub-Saharan Africa and is considered by some as one of the new emerging countries in the world (World Bank, 2015). This is also reflected in Kenya's long-term development plan Kenya Vision 2030, which states the country's target to become a "newly industrialising, middle-income country [by 2030], providing high quality of life to all its citizens in a clean and secure environment" (MENR, 2017b). In addition, the Kenyan government has set the goal of providing universal access to electricity by 2022. However, recent electricity demand forecasts were considerably decreased, due partly to lower than anticipated economic growth rates and partly to delays in the Vision 2030 flagship projects (Republic of Kenya, 2018).

The current scenario of subdued growth in future electricity demand (see LCPDP 2017-2037 reference demand forecast) would lead to overcapacity in generation, as the future generation projects would exceed the needs of the country in the short to medium term (Republic of Kenya, 2018). Generation overcapacity increases the electricity costs for final consumers when pursuing cost-reflectivity of tariffs as revenue requirements of generation increase. Thus, the affordability of electricity would be affected, which is not only essential from a social perspective, but also key to boosting economic growth, industrialisation, and, in particular, manufacturing, as per the Big 4 Agenda[1].

Above-average economic growth and successful implementation of the various Vision 2030 flagship projects could lead, however, to a scenario of higher future electricity demand growth (see LCPDP 2017-2037 vision demand forecast) (Republic of Kenya, 2018). Growing demand must be met by increasing the electricity supply. Decisions on different electricity supply pathways should consider their respective impacts on sustainable development outcomes, such as job creation, health, and environmental sustainability. Equally important is the alignment of such decisions with international commitments, such as reducing Kenya's greenhouse gas (GHG) emissions by 30% below business as usual (BAU) by 2030, as announced in the country's Nationally Determined Contribution (NDC) to the Paris Agreement (MENR, 2017b). Although baseline emissions from electricity generation currently account for less than 2% of total national emissions, projections[2] show that these emissions will rise to approximately 15.7% of total national emissions in 2030, due to significant increases in coal- and natural gas-fired generation capacity (MENR, 2017a).

Both in the scenarios of subdued growth and higher future electricity demand growth, it is key that capacity planning for electricity generation is carried out so that electricity supply matches demand, while enabling the achievement of sustainable development and environmental targets. A major challenge for planners and policymakers in the electricity sector is identifying the optimal combination of electricity generation technologies within the different load-factor categories[3] in order to achieve the best match at the lowest cost.

This study aims at supporting electricity sector planners and decision-makers by comparing the two main power generation technologies that are being considered for future baseload electricity supply in Kenya, namely, geothermal and coal. The role of an energy source and corresponding generation technology in the national electricity supply is determined by a number of factors, including technical considerations, resource availability, environmental characteristics, economics, and other issues that may act as drivers or pose barriers or risks to the development of this source. In Kenya, this role must be considered in the context of the existing long-term sector planning – the 2017-2037 LCPDP –, which provides specifications for cost-optimised generation expansion and sets a clear direction for the development of the electricity sector. Within this context, this study conducts a broad assessment of geothermal and coal-based power generation by analysing the

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[1] President Uhuru Kenyatta's Big Four Agenda includes: food security, affordable housing, manufacturing and affordable healthcare. Source: https://vision2030.go.ke/towards-2030/ (accessed: 16/08/2019).

[2] The analysis underlying the NDC, which was completed in 2015 and used 2010 as a base year, indicated that baseline emissions from electricity generation would increase to 29% of total national emissions by 2030. In 2016, MENR updated the existing baseline using new activity data (2013-2015) and new economic forecasts, projecting emissions to grow from 1.3% of national emissions in 2015 to 15.7% in 2030.

[3] Power generation technologies can be categorised by load factor, differentiating between baseload, intermediate load, and peak load power plants.

current and future roles of these technologies in the Kenyan electricity supply mix (Chapter 1). Chapter 2 assesses the implications of the development of these generation technologies for the power sector in Kenya through a comparative analysis of generation costs (2.1), affordability of electricity (2.2), and flexibility and reliability of electricity supply (2.3). Chapter 3 entails a qualitative and quantitative assessment of the impacts of geothermal or coal-based generation deployment on national development objectives, focusing on the impacts on employment (3.1), as well as health (3.2) and climate change (3.3). The study concludes with recommendations for electricity sector planners and policy makers (Chapter 4).

The report has been developed as part of the *Ambition to Action*[4] project, which seeks to support Kenya in the implementation of its NDC to the Paris Agreement regarding climate change adaptation and mitigation measures in the electricity supply sector. The main objectives and activities under this project include the development of evidence-based planning for electricity supply sector pathways that are compatible with national sustainable development objectives, and the alignment of climate planning processes with the overall electricity sector strategy. Part of the project involves the analysis of the potential role of key renewable energy technologies in Kenya's electricity supply mix, with a focus on geothermal power generation and renewable energy-based mini-grids. This report has been developed in collaboration with the Energy and Petroleum Regulatory Authority (EPRA) and local experts.

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[4] Visit the Ambition to Action website at http://ambitiontoaction.net/ for further details.

2 Context of Geothermal and coal based power generation in Kenya

2.1. Geothermal power generation: status and trends

Geothermal resources in Kenya have been under development since the 1950s. The current installed geothermal power generation capacity stands at 745 megawatts (MW) (as of July 2019)[5], representing about one third of the total installed capacity in Kenya. Kenya's overall geothermal resource potential is estimated at 10,000 MW.

Geothermal generation in Kenya has grown from a small base in the early 1980s to a mainstay of Kenya's electricity sector. The technology has already undergone two phases of rapid development, both contingent upon finance and directives provided by the Government of Kenya (GoK) and, later, the Ministry of Energy (MoE). During the first phase, which took place between 1981 and 1985, Olkaria I was developed. Well drilling stalled in the 1990s due to withheld funding, after which rapid development resumed in a second phase from 1998 to 2017[6], leading to a significant increase in total installed capacity, from below 100 MW to 650 MW (Republic of Kenya, 2018). Today, geothermal development continues to follow an upward growth trajectory. Table 1 gives an overview of the installed capacity and effective capacity by plant for all geothermal plants in Kenya as of July 2019. The planned Menengai I project is currently underway, which is expected to provide an additional 163 MW[7] of capacity upon completion (AfDB, 2011).

Table 1: List of geothermal plants as of July 2019 (based on KPLC, 2018)

#	Geothermal Plant	Installed Capacity (MW)	Effective Capacity (MW)
1	Olkaria I	45	44
2	Olkaria II	105	101
3	Eburru Hill	2.4	2.2
4	OW37 and OW39 mobile wellheads	15	12.2
5	OW43 mobile wellheads	12.8	12.8
6	Olkaria IV	140	140
7	Olkaria I, Units 4 & 5	140	140
8	Orpower 4, Units I, II, & III	121	121
9	Orpower 4, Unit IV	29	29
10	Olkaria V, Unit 1[8]	82	79
	TOTAL	**745**	**734**

The rapid increase in installed geothermal capacity in Kenya was possible due to the embedding of geothermal power generation in a well-established **institutional framework**. MoE and the EPRA jointly share responsibility for the promotion and oversight of geothermal resource development. In 2008, the Geothermal Development Company (GDC) was established as a government-owned special purpose vehicle with the objective to accelerate the development of geothermal resources in Kenya. GDC is responsible for the exploration, appraisal, and development of all geothermal fields (AfDB, 2011). In recent years, the number of Independent Power Producers (IPPs) entering the geothermal generation market has also increased, thanks to an MoE initiative in which GDC undertakes exploration and drilling on behalf of the IPPs and, hence, absorbs the upfront project risks (CDKN, 2014).The dynamic interplay between governmental bodies (GDC in

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[5] Including the 82 MW Olkaria V, Unit 2, commissioned in July 2019.

[6] Including Olkaria 2-5+ development and Menengai appraisal.

[7] 105 MW as part of Phase I by 2019 and 60 MW as part of Phase II by 2022.

[8] Source: https://www.businessdailyafrica.com/news/Kenya-joins-top-8-global-geothermal-producers/539546-5216784-rmxfq/index.html (accessed: 16/08/2019).

particular) and IPPs provides a fertile environment for the development and regulation of new projects. In addition, there is a well-established **legislative framework** to govern and regulate the entire spectrum of geothermal resource development, including exploration, drilling, and power generation and transmission.

All of Kenya's high temperature prospects are **located in the Kenya Rift Valley**, where they are closely associated with the quaternary volcanoes, as can be seen in Figure 1 (Omenda and Mangi, 2016). Currently, geothermal power is only being harnessed in the Olkaria, Menengai, and Eburru fields. In the medium and long term, new geothermal reservoirs, including Suswa, Longonot, Akiira, and Baringo Silali, are planned to be developed. Other potential geothermal prospects within the Kenya Rift Valley that have not yet been studied in great depth include Emuruangogolak, Arus, Badlands, Namarunu, Chepchuk, Magadi, and Barrier (Republic of Kenya, 2018). Located around 75 km from Nairobi, current geothermal sites such as the Olkaria area, the largest producing site, are relatively close to economic activities. Potential new sites such as Suswa or Longonot are even closer to the Kenyan capital.

Figure 1: Locations of geothermal fields and prospects in Kenya (based on Omenda and Mangi, 2016)
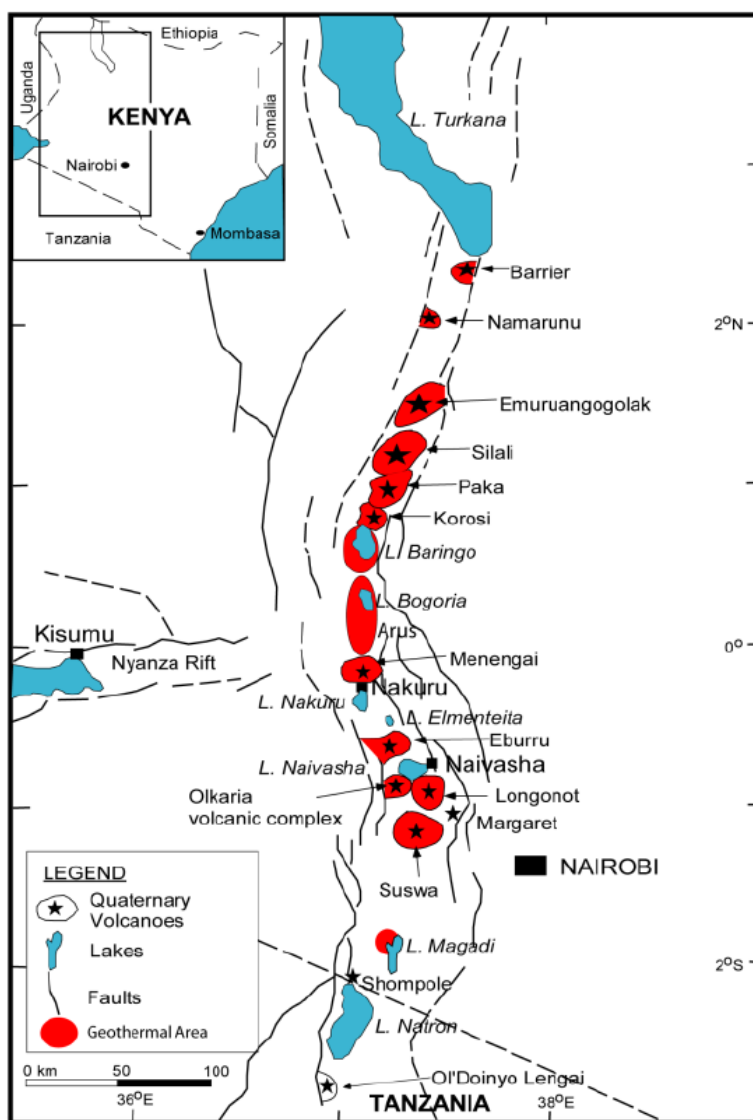
Although there is vast geothermal potential along the Kenya Rift Valley, there are a number of **challenges in the development of the resource**. The harnessing of geothermal energy can be constrained by several factors, including the character of on-site geological formations, which can affect the cost and feasibility of drilling, the temperature and depth of the resource, and the proximity of the resource to available infrastructure, including power lines and access roads. Globally, these factors have posed significant limitations with respect to the development of geothermal resources in the past (NETL, 2013). Other especially difficult issues to address include land acquisition and long power plant lead times, e.g. in the Maasai territory[9] (Newell et al., 2014).

There are three conventional **technologies used to exploit geothermal resources**: dry steam plants, flash steam plants (single, double, and triple), and binary plants (IRENA, 2017). The heat content of a geothermal field typically determines the technology used. *Dry steam plants* use steam of 150 degrees Celsius or higher, and the steam entering the turbine needs to be at least 99.9% dry to avoid scaling and/or erosion of the turbine or piping components (IRENA, 2017). *Flash steam plants* typically require resource temperatures in the range of 177 to 260 degrees Celsius, whereas *binary plants* are designed to utilise geothermal fluids in the range of 85 to 170 degrees Celsius[10]. Among the existing power plants in Kenya, the plants owned and operated by the Kenya Electricity Generating Company (KenGen) are equipped with single flash technology, while the remaining plants owned and operated by IPPs use binary steam cycle technology (Republic of Kenya, 2018). The disadvantage of single flash technology is that its ability to provide flexible power is limited, whereas binary systems can be operated more flexibly.

In addition to that, geothermal resource development offers investors incremental development opportunities as they can start with small installations of about 10 MW and expand their capacity slowly over time, with an average economic lifetime of a geothermal power plant of 25 years, irrespective of the technology used (Sutter and Githui, 2013; Lahmeyer International, 2016).

2.2. Coal-based power generation: status and trends

Coal is one of the few fossil fuel resources available in Kenya for extraction and potential use in power generation. However, coal-based power generation has not been deployed in East Africa to date. This is likely to change with the Lamu coal power plant, a 981 MW plant to be commissioned by 2024, and a 960 MW plant in Kitui, which is scheduled for 2034-36[11] under the Least Cost Power Development Plan (LCPDP).

The planned **Lamu coal-based power plant** will be located in Manda Bay off the Indian Ocean. It will be the first coal-based power plant in Kenya and East Africa and run on imported coal from South Africa (Republic of Kenya, 2018). Given the dependency of the technology used on the coal type, a fuel switch from imported to domestic coal from the Mui Basin later on is not recommended from a technical standpoint, as the power plant would then operate at a lower efficiency (Lahmeyer International, 2016). While coal-based power generation has a long global history and involves proven technologies, with extensive technical experience in the industry, future development in Kenya would, due to the lack of prior implementation, depend (at least initially) on foreign expertise (Lahmeyer International, 2016). In the case of the proposed Lamu coal power plant, the construction tender was awarded to the Chinese company Power China and the Amu consortium, which brings together firms like Gulf Energy, Centum Investment, General Electric, and Power Construction Corporation of China (Njogu, 2018).

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[9] The Maasai land dispute over the Olkaria geothermal project involves a long-term land conflict and a court dispute. The issue with land around geothermal plants is a necessary exclusion zone around well heads, which often results in long running land disputes (Newell et al., 2014).

[10] Source: http://www.geo-energy.org/geo_basics_employement.aspx (accessed: 09/05/2019)

[11] The first unit is scheduled to start operations in 2034, the second in 2035, and the third in 2036. Each unit has a capacity of 320 MW.

The Lamu coal power plant is part of a wider regional initiative focused on making Lamu County a trade and commercial hub. According to MoE, the Lamu coal power plant can support local development along the coast, supplying power to flagship projects such as the Lamu Port South Sudan Ethiopia Transport Corridor (LAPSSET Corridor) project or the Standard Gauge Railway (SGR) project (Lahmeyer International, 2016). In addition to regional flagship projects, Lamu will also evacuate power to more distant destinations such as the 'tech-city' planned outside Nairobi (an air-line distance of around 470 kilometres from Lamu); however, similar to the other flagship projects, this tech-city has not been developed as expected. The three main cities/towns on the LAPSSET corridor will be Lamu, Isiolo, and Turkana, as shown in Figure 2 below. The two latter towns are better supplied by alternative sources of electricity, due to their proximity to supply nodes.

Figure 2: Main towns along the LAPSSET Corridor (based on GoK, 2017)
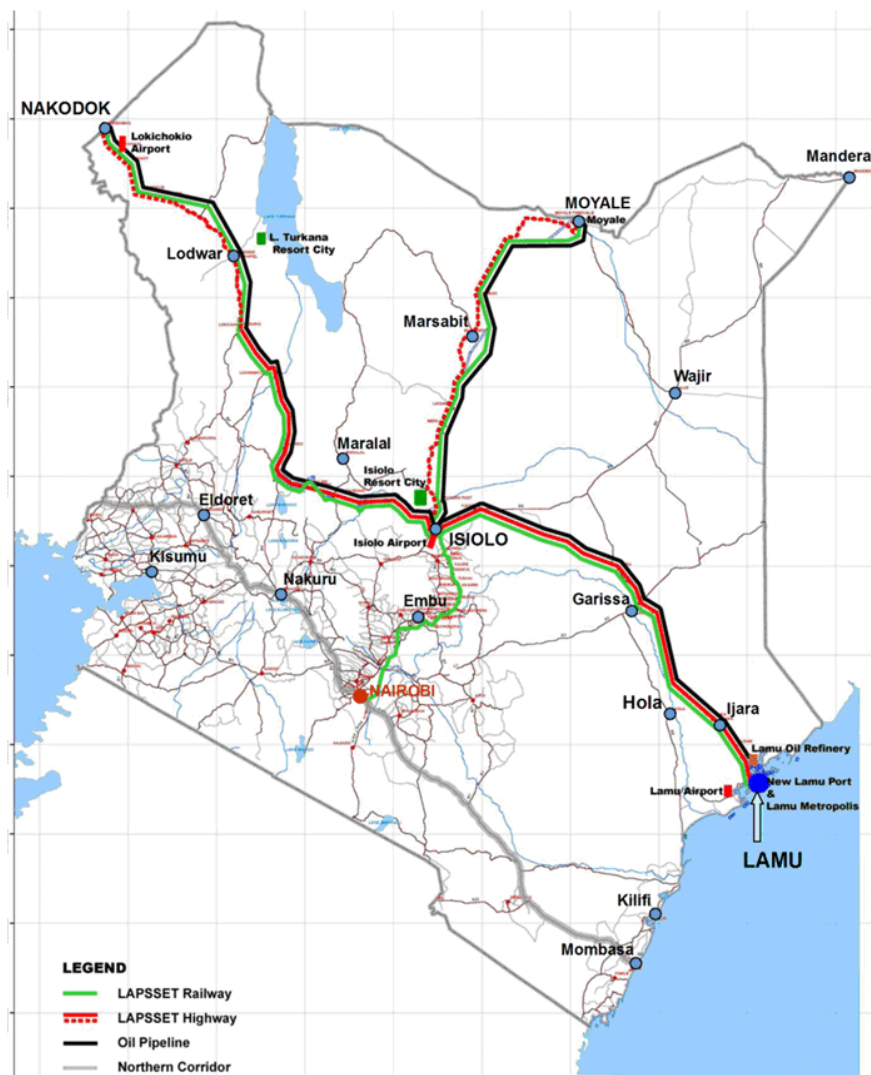
As the Lamu coal plant is planned to run on imported coal, it will be located near port facilities and handling sites. This location allows the imported coal to reach the power plant without long transport routes, and a seawater intake is available for cooling purposes. In addition to the actual construction of the power plant, there are other conditions that must be met in time to ensure successful operation. First, large handling and processing facilities for the imported coal need to be developed and are subject to their own subset of environmental and social impact assessments (ESIA) and thus open to legal challenges. Second, the long distance between Lamu and the main load centres in Nairobi and Mombasa necessitates the construction of a long-distance high voltage transmission line. The estimated associated costs are considerable and have to be factored in when assessing overall project feasibility (Lahmeyer International, 2016). Third, coal generation

developments are also screened in an ESIA, with the process for Lamu currently being heavily criticised for inadequate inclusion of public consultation. As a result, a Kenyan tribunal recently cancelled the environmental licence for the Lamu coal-based power project (IEEFA, 2019a).

Coal reserves in Kenya can be found in the Mui Basin, which runs across Kitui County, 200 kilometres east of Nairobi. The coal basin stretches across an area of 500 square kilometres and is divided into four blocks: A (Zombe – Kabati), B (Itiku – Mutitu), C (Yoonye – Kateiko), and D (Isekele – Karunga). MoE has drilled 76 coal exploration wells across the four blocks and has confirmed the existence of commercially viable coal deposits, amounting to at least 400 million metric tonnes (Wasunna, Okanga, and Kerecha, 2017). The coal has been analysed and found to range from lignite to sub-bituminous coal, with calorific values ranging from 16 to 27 megajoules per kilogramme (MJ/kg). These values are relatively low compared to those of higher-quality bituminous coals (33-35MJ/kg) and anthracites (35-37 MJ/kg) (ScienceDirect, 2009). Further exploration work is ongoing in Blocks A and B, and in 2011, GoK awarded the contract for coal mining in Blocks C and D to a Chinese mining company (Diakonia, 2014). However, as of July 2019, mining activities in Blocks C and D have not yet started. Additionally, MoE plans to conduct exploration activities in Mwingi, Kwale, and Kilifi counties (Ministry of Energy, 2018).

Coal resource development in the Mui Basin in Kitui County is a prerequisite for the commissioning of the Kitui coal plant (Lahmeyer International, 2016). Only when domestic coal becomes commercially available for power generation can the project's detailed design, including the definite site location, be determined. At present, planning is at an early stage, with limited information available. A critical and not yet resolved aspect is the unavailability of the required cooling water in this remote location (Lahmeyer International, 2016).

3 Implications for the electricity sector

3.1. Generation cost

The cost of a certain source for electricity generation is an important (if not the most important) factor for planning and decision making in the electricity sector. A coal-based power plant is typically cheaper to construct, due to the low capital cost, but is expensive to operate because of the fuel needed to run it. A geothermal power plant, on the other hand, is expected to have high upfront costs due to exploration and drilling risks, but lower operational costs due to the lack of fuel costs. However, these assumptions are not always correct; there are various cost aspects that must be taken into account when comparing the cost of geothermal and coal-based electricity generation, in order to make an informed assessment of the overall costs involved in the production of electricity.

The most important cost aspects to be considered in this assessment include:

- Capital expenditure (CAPEX)
- Operations and maintenance expenditure (OPEX)
- Cost of capital
- Legal and regulatory costs
- Decommissioning costs
- Capacity factor
- Levelised Cost of Electricity (LCOE)

Depending on the finance model chosen for building a power plant, the cost of plant construction and operation can be borne by either the private or public sector, or a combination of both. In order for a generation project to be profitable, however, generation costs will – to a certain extent – be passed on to the electricity consumers. Thus, while each cost item needs to be carefully considered by the project developer, it is the levelised cost of electricity (LCOE) that gives an indication of the costs incurred by households.

In the following section, each of the abovementioned cost items, including LCOE, is broken down and discussed for the two technologies. Global data for this analysis is taken from different literature sources, while Kenya-specific data is mostly taken from the 2017-2037 LCPDP, which is the main guiding document for generation expansion in Kenya (Republic of Kenya, 2018).

CAPEX and OPEX

The construction of a geothermal power plant typically involves high CAPEX and lower and more predictable OPEX, since no fuel costs are incurred. Coal-fired power plants, on the other hand, typically involve lower CAPEX, since no exploration or drilling is needed. However, variable OPEX can be significant and difficult to predict in the long term, especially if the coal used in the plant is imported.

Key inputs in the assessment of the electricity generation costs of a given technology include CAPEX and fixed and variable OPEX.

CAPEX is a one-off cost that occurs during the construction of a plant, before it becomes operational. It is typically expressed in United States Dollars (USD) per kilowatt (kW) of installed capacity. For a more thorough assessment, CAPEX must be broken down by individual plant components with different life durations, or by components with different equity investors (EU Commission, 2016). In many cases, the cost of other required new infrastructure (e.g. transmission and distribution grid extension) is accounted for in the CAPEX of a project. These costs depend especially on the size of the power plant and its distance from load centres.

OPEX is a cash expenditure that occurs every year throughout the lifecycle of a plant. Fixed OPEX (i.e. expenditure that does not vary with the output) is typically expressed in USD per year per kW of installed capacity, while variable OPEX (i.e. expenditure that increases with the output) is expressed in USD per kilowatt

hour (kWh). In electricity generation projects, further distinction can be made between variable *non-fuel* OPEX (i.e. expenditure on cooling water, chemicals, lubricant, etc.) and variable *fuel* OPEX (EU Commission, 2016).

The construction of a **geothermal power plant** typically involves high CAPEX due to the high costs incurred in the exploration, resource assessment, and drilling phase, which are all included in CAPEX. OPEX, on the other hand, is typically lower and more predictable. A special feature of geothermal power generation is that it does not require any fuel other than steam, incurring no or very low variable OPEX. Although this is the most common model, there are a few cases in which steam is sold to IPPs who were not involved in the exploration and resource development, in which case there is variable OPEX. The exact costs for a geothermal power plant generally vary and depend on site-specific characteristics such as geology, resource quality (e.g. temperature, flow rate, and chemistry), well productivity, and the power plant type (binary or single flash). Binary plants typically incur higher costs than single flash plants, and the construction of new plants in undeveloped sites is more expensive than adding capacity to existing sites (IRENA, 2017). In Kenya, unlike in a country with no proven resources, the cost of exploration and resource development is significantly lower in productive fields like Olkaria.

For **coal-fired power plants**, the unit CAPEX is typically lower than that of geothermal plants, due to the absence of exploration and drilling costs. A coal plant can be constructed in a fixed timeframe with predictable rates of return, making it more attractive for private investors. Nevertheless, there can be fluctuations in CAPEX due to the choice of technology; the more efficient supercritical and ultra-supercritical technologies' CAPEX is 20-30% higher than that of subcritical technology[12]. Carbon capture and storage (CCS), which involves the capture and geological storage of carbon dioxide emissions from fossil fuel usage, is developing slowly and is not yet economically viable in most cases. Hence, a coal plant with reduced environmental impact is likely to have a much higher CAPEX due to the required CCS. Regarding OPEX, there is a significant difference between the relatively low and predictable fixed OPEX and the more volatile variable OPEX, especially fuel costs, which may be subject to massive price surges in the global market. In a country that is currently fully dependent on fuel imports, these variable operational costs do not create any value within the country.

In Kenya, geothermal power generation has a long history. Several sites exist where the addition of capacity would come at lower than average CAPEX due to lower exploration and drilling risks. Cost-competitive single-flash plants are the predominant technology. Most important, Kenya has an estimated geothermal potential of more than 10,000 MW. Coal-based power generation, on the other hand, is new to Kenya. Therefore, the technology, expertise, and fuel will need to be imported. Although Kenya has domestic coal resources, the first coal power plant in Lamu is planned to run on imported coal (Republic of Kenya, 2018). Coal imports will likely come from South Africa. According to World Bank reports, average coal prices are constantly on the rise in South Africa and have increased from USD 64 per tonne in 2016 to USD 81.9 per tonne in 2017. The 2017-2037 LCPDP takes USD 81.9 per tonne as a base price in all three generation expansion scenarios and projects this price to rise to USD 100 per tonne in 2020 and USD 108 per tonne in 2030. In the case of Lamu, fuel costs are projected to account for 96.6% of total variable costs of the plant (Republic of Kenya, 2018). There is still uncertainty with regard to the technology of the planned coal plant. Ultra-supercritical technology would increase CAPEX significantly but reduce variable OPEX, due to efficiency gains. Any less efficient technology may increase uncertainty about long-term variable OPEX and may incur significant emissions-related costs if Kenya introduces a carbon price.

Table 2 shows ranges for CAPEX and OPEX (both fixed and variable) for geothermal and coal-based power generation. Figures for Kenya are taken from the 2017-2037 LCPDP, which outlines costs for the two coal power plants in Lamu and Kitui and five geothermal sites (Republic of Kenya, 2018). These ranges can be compared to global averages, taken from the International Energy Agency (IEA/NEA/OECD, 2015). According to both Kenya-specific and global figures, CAPEX and OPEX are higher for geothermal power generation than for coal-based, except variable fuel OPEX, which is generally not incurred in geothermal generation. Assuming

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[12] Source: http://www.world-nuclear.org/information-library/energy-and-the-environment/clean-coal-technologies.aspx.

that geothermal exploration and drilling costs decrease further in the future due to advances in equipment and technology, while coal prices increase due to more serious restrictions on coal mining, it is likely that the situation will reverse at some point.

Table 2: Kenya-specific & global ranges of CAPEX and OPEX for geothermal and coal-based power generation (based on Republic of Kenya, 2018 and IEA/NEA/OECD, 2015).

Cost	Technology	Kenya (range)	Global (range)
CAPEX (in USD/kW)	Geothermal	3,440 – 4,580	4,360 – 6,240
	Coal	2,430 – 2,500	2,930 – 6,600
OPEX (fixed) (in USD/kW-y)	Geothermal	150 - 170	100 - 132
	Coal	68 - 69	31 - 80
OPEX (variable) (in USD/MWh)	Geothermal	-	-
	Coal	37 - 38	15 - 38

Nevertheless, in the meantime, the Lamu coal plant, which will be constructed and operated by a consortium of Power China and Amu Power, will leverage large amounts of private capital, while much of the geothermal development in Kenya is government-financed. Thus, from the government's perspective, a focus on the expansion of geothermal power increases public debt, at least in the short to medium term. However, since the government has a serious interest in providing secure and affordable electricity to all Kenyan citizens, as stated in the country's Vision 2030, other cost aspects besides CAPEX and OPEX must be considered.

Cost of capital

While the cost of capital for geothermal power projects in Kenya is already relatively low compared to the average cost of capital for global coal power projects, it is likely that this difference will become more marked in the future; more and more international financial institutions are withdrawing from coal investments, whereas geothermal power is receiving increasing support from public and private finance institutions around the world.

When analysing the cost of capital or the financing cost, three main types of capital to fund power generation projects can be distinguished: i) equity, i.e. money contributed by the owners of a project from their own sources; ii) loans, i.e. funds borrowed from financial institutions against a predetermined repayment schedule; and iii) grants, an optional source of funding provided by a donor, with no obligation of repayment.

To calculate the interest rate that needs to be paid on each form of financing in a power generation project, the Weighted Average Cost of Capital (WACC) can be determined. The WACC projects the minimum return that a project developer must earn to satisfy all providers of capital. In some cases, the WACC is very low (e.g. in the combination of a high percentage of grant financing, a concessional interest rate for the loan, and low equity share with low return on equity).

For renewable energy projects in Kenya, including geothermal, Pueyo et al. (2016) calculate a WACC of **5%** for KenGen (i.e. government supported) projects and **11%** for projects developed by IPPs. Geothermal specific data at the global level is not available. Likewise, no Kenya-specific data for the cost of capital for coal projects has been collected as of today. On the global level, the World Bank estimates that the WACC for a typical coal power project in middle-income countries is roughly **13%** (Jones, Purvis, and Stevenson, 2011). The data is summarised in Table 3.

Table 3: WACC for geothermal and coal projects in Kenya and worldwide (based on Jones, Purvis, and Stevenson, 2011; Pueyo, Bawakyillenuo and Osiolo, 2016).

WACC (in %)	Kenya (public / private)	Global
Geothermal	5 / 11	n.a.
Coal	n.a.	13

It is important to note that many of the publicly funded financial institutions, e.g. multilateral development banks and export credit agencies based in Organisation for Economic Co-operation and Development (OECD) countries, have adopted strict lending rules for new coal power projects. The trend is spreading across other western financial institutions (including commercial banks), evidencing a geographical shift towards Asian institutions taking greater leadership in coal power project finance. In this context, it is likely that future funding trends in the coal sector will be determined by the business strategies of the banks and their responses to environmental regulations and market conditions, which will vary from region to region. Thus, it is uncertain to what degree funding will be available for new unabated coal plants (Baruya, 2017). It is reasonable to assume that the cost of capital will increase.

Geothermal power generation, on the other hand, is receiving increasing recognition and support from international financial institutions, including the World Bank. As a low-carbon energy source that can offer reliable and sustainable baseload power, geothermal energy plays a central role in the strategic deployment of concessional climate finance, which can mitigate risks associated with the initial stages of geothermal development. Apart from multilateral development banks building a strong portfolio to help countries tap into their geothermal potential, countries themselves are also establishing de-risking mechanisms to attract and assist geothermal project developers in the early stages of their investment.[13]

In the case of Kenya, the development and success of geothermal power generation has been, to date, mostly driven by strong government commitment and the availability of public funds. Since 2009, GDC has effectively supported the de-risking of geothermal fields using public funds, promoting exploration and drilling in new fields. Furthermore, Kenya is a core country in the support programme of the Geothermal Risk Mitigation Facility (GRMF), which was established in 2012 by the European Commission, with support from the German Federal Ministry for Economic Cooperation and Development (BMZ) and the EU-Africa Infrastructure Trust Fund (EU-Africa ITF), via KfW Entwicklungsbank. In the first four application rounds (2012-2016), Kenya received USD 33.6 million to support surface studies and drilling programmes. More than half of the amount (USD 19 million) was granted to GDC, with the rest going to private project developers (African Union, 2018).

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[13] Source: https://www.worldbank.org/en/news/feature/2018/05/03/geothermal-energy-development-investment (accessed: 23/01/2019).

Legal and regulatory costs

The new Energy Act 2019 lays out the rules for the licensing process and a new royalty scheme for geothermal power generation, making it easier to assess the legal and regulatory costs associated with new geothermal projects. For coal-based generation, on the other hand, the Energy Act stipulates that regulations still need to be developed. It is therefore unclear to what extent coal-based power generation will incur legal and regulatory costs once the necessary regulations have been adopted.

Legal and regulatory costs include licensing fees, royalties, and costs for government permission, land acquisition, and environmental approval. These costs are generally highly contextual and/or project specific, and little data on them is publicly available.

In Kenya, a new Energy Act was passed on March 2019. According to the Act, the Cabinet Secretary grants licences for geothermal resource exploitation for up to 30 years, with the option of renewal for five years (Government of Kenya, 2019). Moreover, the Act lays out the following royalty fee system for geothermal plant operators: a 1-2.5% royalty fee will be applied to revenues generated from geothermal resources for the first decade of the granted licence, which will increase to 2-5% thereafter. All royalties from geothermal energy must be paid into the Treasury of the National Government and will be apportioned among the national government (75%), county government (20%), and local community (5%) (Government of Kenya, 2019).

Regarding coal-based power generation in Kenya, the new Energy Act stipulates that a licence or permit is required for the production of energy from coal. Further regulations on the use of coal are still pending, with the Act specifying that the Cabinet Secretary is in charge of making these regulations on the recommendation of EPRA (Government of Kenya, 2019). Concerning mining activities related to coal-based power generation, the Mining Bill 2015 has a number of onerous provisions that may weaken Kenya's attractiveness for investors. The proposed royalty rates for coal are at 8% - higher than those charged in comparable jurisdictions.[14]

Finally, the introduction of a carbon tax or a carbon-based cap-and-trade system could increase the cost of coal generation considerably – with effects being felt either by consumers (carbon tax) or the operator (cap and trade). Neither of the two schemes would have a big impact on the cost of geothermal power generation.

Decommissioning costs

Little data is available on the costs of decommissioning geothermal plants, since very few plants have been decommissioned to date worldwide. The decommissioning costs for coal plants, on the other hand, range between USD 50,000 and 160,000 per MW, depending on the environmental remediation required and the location. No Kenya-specific data is available for either of the two technologies.

The cost of decommissioning power plants varies widely based on a variety of location-specific factors, including the extent of environmental remediation required to meet the desired end state, the physical location of the plant, and the potential salvage value of equipment and scrap. Costs generally increase when the environmental remediation requirements are significant, plants are located in densely populated or highly remote areas (locations that create logistical challenges), and/or salvage values are low (Raimi, 2017).

To date, only a few geothermal power plants have been decommissioned in over one hundred years of global geothermal development (although some plants run below capacity due to resource limitations); hence, there is little data on concrete decommissioning costs for geothermal power plants. It can be assumed that the decommissioning costs of geothermal power plants increase with plant capacity and remoteness.

In contrast, the largest percentage of retired capacity in recent years has come from coal-fired plants. Compared to other technologies, coal power plants tend to have the highest overall decommissioning costs due to their age, large size, and various environmental remediation requirements. According to Raimi (2017),

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[14] Source: https://oxfordbusinessgroup.com/analysis/natural-response-government-seeks-make-most-its-resources (accessed: 14/02/2019).

decommissioning costs per MW for coal plants range between USD 50,000/MW and 160,000/MW (Raimi, 2017).

Capacity factor

As a general rule, the higher the capacity factor of a power generation plant, the more power it can produce over the course of a year and the lower the cost per unit of electricity generated. Geothermal and coal-based power plants are both considered baseload power plants, and can both operate at relatively high capacity factors, with the average capacity factor for geothermal (90%) slightly exceeding the average capacity factor for coal-based power (85%).

The CAPEX of a generation technology or power plant, as indicated above, refers to the cost to install one kilowatt of generating capacity. The generating capacity referred to is the plants' nameplate capacity, i.e. the maximum amount of power this plant can produce under ideal circumstances. In most cases, however, a power plant will not be able to always produce power at full capacity. Its output may vary based on maintenance issues, fuel costs, or instructions from the grid operator. In this context, the capacity factor of a power plant is the ratio of the plant's actual annual power output to the amount of power it would produce annually if it ran at full capacity. Baseload power plants, such as geothermal or coal-based plants, typically operated continuously at high output with a corresponding high capacity factor (Breeze, 2010).

Although the capacity factor is not a cost per se, it has a significant impact on the economics of power plant operations. The higher the capacity factor of a plant, the more power it can produce over the course of the year and the lower the cost per unit of electricity generated. Traditional baseload power plants, including nuclear, gas, and coal plants, typically operate with high capacity factors (90%, 87%, and 85%, respectively), while many renewable energy technologies, in particular those relying on intermittent sources, have lower capacity factors (e.g. 34% for onshore wind and 31% for solar thermal). Geothermal is the only renewable energy source that can compete with the conventional technologies in terms of capacity factor, with a typical figure of 90%, due to continuous resource availability (Breeze, 2010). Thus, assuming geothermal and coal-based power plants run at their typical capacity factors, the effect of the capacity factor on the cost per unit of electricity generated should be similar.

However, capacity factors can be adjusted by system operators in order to balance supply and demand. If, as is the case in Kenya, significant oversupply threatens the economic viability of the power sector, the capacity factor of baseload plants can be adjusted downwards. In Kenya, geothermal power plants are currently the only type of baseload power plant with a high capacity factor. Once the Lamu coal power plant is added to the system for provision of additional baseload power, running this plant at full capacity would increase the oversupply in the Kenyan power system. From an economic perspective, it therefore makes sense to reduce the capacity factor (and, thus, the power output) of the coal plant, since it has a higher variable OPEX than geothermal plants. This approach can be observed in the 2017-2037 LCPDP, in which cost optimisation results in significantly lower capacity factors for the Lamu coal plant, while geothermal plants are expected to run at a relatively high capacity factor throughout the planning period. This, in turn, has an impact on the levelised cost of electricity (LCOE) for both technologies, which would not be the case if both technologies were run at their typical capacity factors.

Levelised Cost of Electricity (LCOE)

LCOEs are always highly country- and context-specific. In the case of Kenya, the estimated LCOE for coal-based power is three times higher than the estimated LCOE for geothermal power in the period from 2017 to 2037. This can be attributed to the very low capacity factor predicted for coal-based power generation in the latest LCPDP, while geothermal plants are expected to run at a higher capacity factor throughout the period.

A useful tool for comparing the unit costs of different technologies over their operating lifetimes is the Levelised Cost of Electricity (LCOE), which represents the discounted lifetime cost divided by the discounted lifetime generation of a power generation technology or system, expressed as cost per kWh or MWh. Respective

figures can be retrieved from global cost analysis (e.g. IEA/NEA/OECD, 2015) and the 2017-2037 LCPDP for Kenya (Republic of Kenya, 2018).

The 2017-2037 LCPDP outlines the LCOEs for different generation expansion scenarios[15] and provides individual LCOEs for future generation expansion candidates, per generation unit and over a range of capacity factors. Based on this data and taking into account the capacity factors for each generation expansion scenario, an estimate of the average LCOEs for geothermal and coal-based power generation expansion candidates can be derived.

According to the 2017-2037 LCPDP, geothermal plants will run at an average capacity factor of 77.22% in the Reference Case. Coal plants, on the other hand, will run at an average capacity factor of 6.8% in this scenario.[16] Looking at the LCOEs of future geothermal and coal-based power generation expansion candidates over a range of capacity factors, this would translate to an LCOE of USD 10.7 cents/kWh for geothermal and a minimum of USD 29.5 cents/kWh for coal.[17] Assuming that both geothermal and coal would perform at their maximum capacity (i.e. with capacity factors above 80%), this would translate to an LCOE of USD 8 cents/kWh for geothermal and USD 10.5 cents/kWh for coal. The LCOEs for both technologies are summarised in Table 4.

Table 4: Kenyan & global LCOEs for geothermal and coal-based power generation (based on Republic of Kenya, 2018 and IEA/NEA/OECD, 2015).

LCOE (in US cents/ kWh)	Kenya (Reference Case)	Kenya (if running at maximum capacity factor)	Global (range)
Geothermal	10.7	8	3-14
Coal	29.5	10.5	7-12

At a global level, the LCOEs for both geothermal and coal show broad ranges, underlining the fact that generation costs are highly country- and context-specific. When looking at Kenya specifically, it is striking that the LCOE for coal is three times higher than that for geothermal, across the different generation expansion scenarios. This can be attributed to the significant difference in predicted capacity factors for the two technologies in the three scenarios. However, even under the assumption that each technology performs at its maximum capacity, the LCOE for coal is still higher than the one for geothermal.

The LCOE for a certain power generation technology has, together with several other factors, direct implications on the affordability of electricity, which is discussed in Section 2.2.

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[15] For the development of the 2017-2037 LCPDP, three different generation expansion scenarios where modelled: a Fixed System Case, an Optimised Case, and a Fixed Medium-Term Case. For each case, simulations were derived for three different demand forecasts: the reference, the vision, and the low demand forecast. The Fixed Medium-Term Case under the reference forecast scenario was used as a basis for deriving the long-term expansion plan for the electricity sector for the period from 2017 to 2037, since it was considered to best reflect the reality. This case will be referred to as the Reference Case in the remainder of the study.

[16] These values are derived by taking the average capacity factors for geothermal and coal, respectively, for the Fixed Medium-Term case under the reference demand forecast (based on Table 35, p. 109; Table 40, p. 124; and Table 43, p. 135 in 2017-2037 LCPDP).

[17] These values are derived by taking the average LCOE across the generation expansion candidates for geothermal and coal, respectively, in their respective capacity factor ranges (based on Figure 17, p. 85 in 2017-2037 LCPDP).

3.2. Affordability of electricity

In addition to the electricity generation costs associated with different technologies, as outlined in Section 2.1, various other factors influence retail electricity tariffs, which determine the extent to which electricity is affordable for households and businesses. The affordability of electricity is an important issue in Kenya, due to its impact on economic growth, poverty reduction in marginalised communities, and industrial development. The development of manufacturing industries, in particular, is one of the key development objectives of the Big 4 agenda established in 2018. In April 2019, the retail tariff for electricity for domestic customers was Kenyan Shilling (KES) 15.8 per kWh (USD 0.16), with a total electricity cost of KES 22.59 per kWh (USD 0.22), including variable costs and taxes (Regulus Web, 2019). At approximately USD 0.22 per kWh, the cost of electricity in Kenya in 2019 was comparable to the global average, but approximately double that of other major Sub-Saharan African economies, such as Nigeria and South Africa (Foster, 2017).

The stability of electricity prices also plays an important role in determining the affordability of electricity, particularly for businesses, whose economic viability may depend on the predictability of prices. Figure 3 shows that after a period of significant volatility in the average cost of electricity between 2009 and 2014, price stability improved slightly in the following 5-year period up to 2019. Nevertheless, Figure 3 also shows that prices in 2018 and 2019 were nearly the highest they had ever been over the 10-year period; consequently, the affordability of electricity remains not only important for economic development, but also a highly politicised issue. One contributing factor to the electricity price variation is Kenya's dependence on imported fossil fuels, mostly crude oil, the price of which fluctuates significantly, as can be seen in Figure 4—a characteristic associated with electricity generated by fossil fuels in general, including coal.

Figure 3: Average domestic electricity prices in Kenya 2009-2019 (KES/kWh) (based on Regulus Web, 2019)
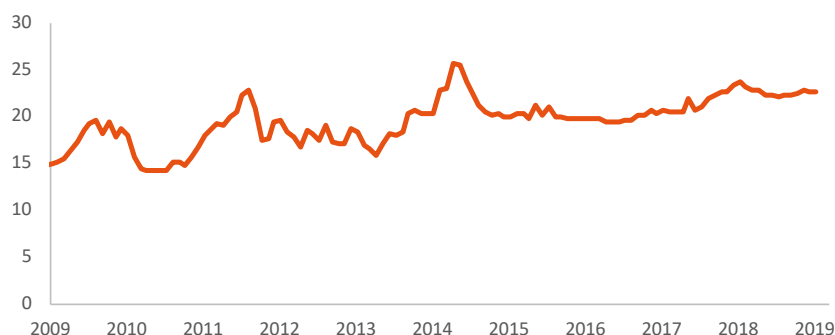

Figure 4: Average price of crude oil 2009-2019 (USD per barrel)[18]

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[18] Graph based on: https://www.macrotrends.net/2516/wti-crude-oil-prices-10-year-daily-chart (accessed: 16/08/2019).

Efforts to improve the affordability of electricity may include minimising tariffs by reducing the overall annual costs of the electricity sector, as well as making tariffs less prone to fluctuation by increasing the certainty and reducing the risks associated with different system cost components. A key risk is the dependence on imported fossil fuels, the prices of which are driven by geopolitical factors beyond the control of the government. Minimising the contribution of such sources to the overall electricity supply will ensure longer-term price stability and predictability.

This section looks at the impact of adding more geothermal and coal capacity on electricity retail tariffs, as well as cost stability. In addition to overall capital and operational expenditures, the timing and consistency of these expenditures is considered, as well as the risk of costs associated with surplus capacity and the implications of the negotiated structure of purchase power agreements.

The impact of CAPEX and OPEX on system cost and cost stability

The addition of more geothermal capacity in Kenya would have advantages over deployment of coal-based generation, both in terms of limiting the overall system costs and the retail price and ensuring cost stability.

The clearest contributors to the overall electricity sector costs are the capital and operational expenditures associated with the construction and operation of power plants. Section 2.1 found that the LCOE for geothermal power is predicted by the 2017-2037 LCPDP to be lower than that of coal, at an average of USD 0.08/kWh, compared to USD 0.10/kWh for coal, assuming both technologies are performing at maximum capacity.

Another significant difference between the costs of geothermal and coal power production, as outlined in Section 2.1, is the predictability of the costs throughout the plant's lifetime. The largest part of the costs for geothermal production, both CAPEX and OPEX, are fixed costs, with the cost of labour being the only significant variable factor that could lead to price changes; such developments in the labour market are long-term and somewhat predictable. In contrast, a significant portion of the costs for coal power generation are variable costs for fuel input (in the case of Lamu, fuel costs will make up 96.6% of total variable costs), and these are costs that cannot be forecasted with a high degree of confidence. Since the outlook for coal as a commodity is even more unpredictable in the coming decades than it has been historically, as more businesses and countries respond to the Paris Agreement with pledges to wind down or completely phase out coal consumption, there is no reason to expect that the price of coal will become any more stable in the future than it has been in the past.

Another difference related to CAPEX is in the timing of investments: while coal power capacity is typically characterised by very large capacity additions, causing significant spikes in capital investment costs over time, geothermal power plants are typically much smaller and can be developed more gradually to follow the load, allowing, in theory, for more consistent annual capital investment spread across the years.

Cost of surplus capacity

Geothermal power typically entails a lower risk of additional costs arising from surplus capacity, due to its ability to better align capacity expansions with actual demand growth. The introduction of a 981 MW coal plant in 2024 may increase the cost of electricity by up to 50% due to the surplus capacity that such a large-scale installation would entail for a period of at least several years.

An increasingly significant portion of the overall electricity costs are the costs associated with surplus capacity. Surplus capacity – generation capacity that is not utilised to its full capacity, since it would otherwise represent excessive electricity supply – still incurs costs for the continued maintenance and partial operation of those power plants.

Under the 2017-2037 LCPDP, surplus capacity is forecasted to become a very significant issue from 2020 onwards, as capacity expansion outpaces projected demand growth. By around 2025, surplus capacity will

exceed 1,500 MW; more than 30% of generated electricity will be excess, while nearly the same proportion of potential geothermal steam will be vented (Republic of Kenya, 2018).

The ability to minimise surplus capacity depends on the ability of a generation technology to respond to changes in demand in the medium and long term—that is, to ensure that capacity additions are gradual and reflect the pace of demand growth, as explained in greater detail in Section 2.3. Multiple smaller installations that can be introduced gradually have an advantage over larger installations that are constructed with the perspective of meeting future demand.

This highlights a significant difference between coal and geothermal power generation. The coal power plant planned in Lamu is currently set to bring an additional capacity of 981 MW online in a single year in 2024, while peak demand is forecasted to increase by an average of approximately 120 MW per year between 2020 and 2030. The introduction of such a large amount of capacity over a short period of time will lead to a large portion of this capacity being surplus for a number of years. For example, the 2017-2037 LCPDP finds that the addition of a 981 MW Lamu coal plant in 2024 will aggravate the projected supply-demand imbalance to the extent that the surplus margin will surpass 1,500 MW, with the system's LCOE rising rapidly to KES 16.86/ kWh by 2024 as a consequence. This will make electricity 50% more expensive than the average LCOE of KES 11.07/ kWh estimated for the Optimised scenario across the planning period, in which this coal plant would not be introduced before 2030 (Republic of Kenya, 2018). By comparison, since geothermal power plants are typically smaller – ranging in size from 10 MW to 158 MW in Kenya –, they can be introduced more gradually and as necessary to meet the demand growth, thereby reducing surplus capacity and the associated costs.

Structure of negotiated Power Purchase Agreements

The difficult investment conditions for project developers of coal power plants are such that Power Purchase Agreements (PPAs) are likely to be negotiated with less attractive conditions for the GoK than PPAs for geothermal power plants. Prices will be more uncertain and will contain a higher degree of risk-related inflation. The conditions will also likely lead to a much higher risk of payments for empty capacity charges.

PPAs are usually established between the Kenya Power and Lighting Company (Kenya Power), which is Kenya's main electric utility, and the IPP at the point of project inception, to agree on the conditions under which power will be purchased from the plant, including the conditions that determine the price at which power will be purchased. The three elements of PPAs that determine the costs and risks incurred through the agreement are 1) the **capacity charge** that is paid to cover the fixed operating costs of the facility, depending on the capacity size and regardless of the output; 2) the **variable generation component,** which is paid depending on the amount of output delivered; and 3) a **fuel price adjustment**, which adjusts the variable generation component depending on unforeseen changes in the indexed price of fuel imports.

Capacity charge and variable generation components

The *capacity charge* is a fixed charge that is paid to the IPP in return for the *availability* of their generation capacity, regardless of the power output that is ultimately used. This is effectively a charge to ensure the availability of the plant's capacity. It provides the purchaser with a guarantee that the capacity will be available when required and the producer with a guarantee that the essential costs of installing and operating the plant will be covered, even in the case of no or limited demand for electricity. The *variable generation component* is the payment that is made by the purchaser per unit of actual electricity generated, in response to the purchaser's demand. In effect, the negotiated charge usually covers the marginal operational cost of generating electricity, assuming that the plant is functional and operating.

The price that the capacity charge can be negotiated at depends on the perceived risk of surplus capacity; if the project developer considers there to be a higher risk that the plant will produce surplus capacity, then it will not be an economically rational business decision to initiate the project unless a very high capacity charge is agreed on to account for this risk. By comparison, if there is more reason to believe that demand for electricity

will be reliable, then a smaller capacity charge would be sufficient for a project developer to build a viable business case. A higher capacity charge, or risk guarantee, is attractive for project developers, since it provides higher reliability of income, regardless of actual developments in electricity demand. For the same reason, it is unattractive for the purchaser, since it commits the purchaser to payments even in the case where no electricity is required. In lower risk projects, the purchaser would seek to make a deal in which the capacity charges can be reduced in favour of higher charges for the variable generation component.

Although geothermal projects may require higher upfront capital expenditure, developers of large coal projects are very likely to require a higher capacity charge than developers of smaller geothermal projects, due to the higher uncertainty regarding the demand for the electricity generated. Investments in coal are more likely to lead to surplus capacity and therefore entail a higher risk of underutilisation. The PPA agreed on for the Lamu coal plant reflects this, as it includes a particularly high capacity charge of USD 360 million per year, which translates to about KES 100 million per day, in a take-or-pay agreement in which Kenya Power will pay for the plant's output capacity regardless of whether or not the power is actually purchased (IEEFA, 2019b). Furthermore, in the case of surplus capacity, geothermal generation is identified in the LCPDP as a higher priority option for dispatch, due to its lower marginal costs; thus, coal power is less likely to be used, even though it would be responsible for the surplus and high associated cost.

In addition to capacity charges being higher for coal, these charges are also likely to be more damaging to the purchaser, since they are more likely to represent *empty* or *wasted* capacity charges than those for geothermal, due to the higher risk of surplus capacity associated with coal installations.

Fuel price adjustment

Usually, a clause for a tariff adjustment exists in PPAs, covering adjustments for inflation, changes in governmental legislation, and unexpected changes in the import price of fuels. Adjustments related to changes in the import price of fuel are attractive for producers, since they effectively flexibly cover the variable component of the operator's input costs and guarantee a specific project margin regardless of import costs. These adjustments are unattractive for the power purchaser, since they represent considerable uncertainty in the price that will be paid for electricity in the future. As geothermal power plants do not require fuel imports for operation, the relevance of this issue is insignificant, compared to coal power plants, where fuel imports account for a large portion of the variable operational costs. To illustrate the risk associated with fuel imports for coal power projects, it is currently estimated that the cost of fuel imports for the Lamu coal power project would be at least double the value estimated by the project developer in 2014, according to current trends (IEEFA, 2019b).

While the PPAs determine the costs for the retailer—Kenya Power, in this case—, changes in the variable cost elements are usually passed on to the power consumer. As such, the Foreign Exchange Rate Fluctuation Adjustment (FERFA) and the Fuel Cost Charge (FCC) have a direct impact on consumers' electricity bills:

Foreign exchange levy and fuel cost charge

FERFA and FCC are pass-through costs that vary according to the prevailing currency exchange rate and international crude oil prices. Pass-through costs are variable monthly costs borne directly by the consumers, as they cover components of the electricity cost that change from time to time. The FERFA rate is applied to cushion the IPPs from the projected cash flow variation associated with the shifting exchange rate between the Kenyan Shilling and major global currencies, especially the US Dollar, which is used to finance a significant portion of the capital and operational costs (Republic of Kenya, 2018a).The FCC varies as a result of the fluctuation in international crude oil prices and the amount of imported fossil fuels used in emergency power plants. This type of cost will not be applicable to the Lamu coal plant.

3.3. Flexibility and reliability

Flexibility is the ability of a power plant to maintain continuous service in the face of rapid, large changes in supply or demand. Flexibility is essential for reliable power plant operations and mitigation of disturbances such as outages and is, thus, an important aspect to assess, in addition to generation costs and affordability. In a reliable power system, flexibility is provided mainly by controlling the supply side, with the two key tasks for the power plant fleet being to track all variations in demand and adjust power output accordingly (**load following**) and to ensure that the system stays in balance in the case of contingencies (**sector stability**).

It is therefore appropriate to analyse two things: the **load type and operational flexibility** at the plant level and the impact of existing and planned geothermal and coal-based power generation on electricity **sector stability** at the system level in Kenya.

Load type

Both geothermal and coal-fired power plants are considered baseload power plants. However, globally, geothermal plants can reach higher capacity factors than coal—92%, compared to 85 percent. In Kenya, these numbers diverge significantly from the global average; according to the 2017-2037 LCPDP, the average capacity factor of geothermal plants is 76%, compared to a forecasted average capacity factor of 8% for coal-fired power plants, which means that the proposed coal-based power plant would be grossly underutilised.

The demand for electricity, also referred to as *load*, faced by a power plant is constantly changing, due to changes in business and residential activity, as well as weather conditions. The daily load shape determines how power plants are operated and how the composition of the power plant fleet should be designed with regard to the different load types in demand. The load factor of a power plant is indicated as the percentage of hours that a power plant operates at its maximum capacity in a given time period. Depending on the load factor, power plants can be categorised as baseload (inflexible generation), intermediate load (flexible generation), or peak load (highly flexible generation) (Hynes, 2009). The minimum demand for electricity that occurs throughout the day (base level) is usually met with baseload generating units, which have low variable operating costs. Baseload units can also meet some of the demand above the base and can reduce output when demand is unusually low (Kaplan, 2008). The units do this by ramping generation up and down to meet fluctuations in demand, as explained in more detail below. Baseload power plants typically have annual load factors that exceed 75% and are usually above 90 percent. Power plants that fall into this category are generally larger (around 400 MW) fossil fuelled plants such as coal or natural gas or, on the renewable side, geothermal, hydropower, and biomass (Hynes, 2009).

Geothermal power plants are characterised as providing stable production output, unaffected by climatic variations. This allows for high capacity factors that range from around 60% to 90% globally, making the technology suitable for baseload production (IEA, 2018). Compared to other baseload energy sources, geothermal power has the highest capacity factor (92%) , higher than gas (87%), coal (85%), or biomass (83%) (GEA, 2013a). According to the 2017-2037 LCPDP, geothermal plants will run at an average capacity factor of 77.22% in the Reference Case (Republic of Kenya, 2018). In this case, geothermal provides reliable renewable baseload power at a low operating cost. With a minimum capacity factor of 75%, geothermal power plants are usually considered must-run power plants, i.e. a high priority option for dispatch. This is based on the conservative assumption that geothermal power plants are equipped with single-flash technology, which is the commonly applied technology in Kenya today. Currently, geothermal plants in Kenya are designed and financed for continuous operation and are consequently hardly dispatchable. A reduction of the power output to below 70-80% of their available capacity is feasible, but only under specific conditions, which are described in further detail below (Lahmeyer International, 2016).

The ideal capacity factor of a **coal-fired power plant**, across its average lifetime, is 75 percent (Lahmeyer International, 2016). In practice, however, the world's coal plants were running on average around half the

time in 2016, with a capacity factor of 52.2%. The trend is similar in the US (52%), EU (46%), China (49%), and India (60%) (Carbon Brief, 2018).

According to the 2017-2037 LCPDP, the share of coal in total installed capacity in Kenya is expected to increase from 0% to 19.5% in the study period (Republic of Kenya, 2018). In the same document, it is also stated that the average capacity factor of coal in Kenya is expected to be 6.8% in the Reference Case (Republic of Kenya, 2018). In this scenario, the Lamu coal power plant would be grossly underutilised, should demand only grow moderately (Republic of Kenya, 2018). These factors are in stark contrast to the underlying assumptions of the planners of the Lamu coal power plant. The project developer Amu Power, in contrast, expects an annual capacity factor of 85 percent (AFDB, 2016).

Operational flexibility

Although a geothermal power plant operates most efficiently when it runs continuously, it can also provide flexible power if contractual terms are modified accordingly. While operating a binary system more flexibly typically does not increase operations and maintenance (O&M) costs, the flexible operation of a flash or dry steam system can increase these costs slightly, as it involves venting steam. Similarly, the flexibility of coal-fired power plants can be increased through technical retrofits. However, this may have an impact on the lifetime of the plant and is associated with an increase in O&M costs.

As electricity supply and demand must always be in balance, technologies are required that can respond to changes in both demand and power generation, especially considering the uptake of intermittent renewable technologies in many countries. Renewable energy technologies have witnessed a rapid expansion in power systems worldwide due to immense cost reductions over the past decade (Agora Energiewende, 2017a). In Kenya, variable renewables, in particular wind and solar photovoltaic (PV), are planned to play a growing role in the country's electricity generation mix. In the period 2017-2037, the share of wind and solar PV in the overall generation mix is expected to increase from 1.1% to 11.9% and from 0% to 10.8%, respectively (Republic of Kenya, 2018). Variable renewable energy sources are non-dispatchable sources, i.e. power cannot be supplied on demand, as in the case of energy sources with continuous availability, such as geothermal energy and coal (Gonzalez-Salazar, Kirsten and Prchlik, 2017). Because of their variable output and close-to-zero marginal generation costs, variable renewables alter the characteristics of electricity systems and markets. Steeper and more variable residual loads increase the flexibility requirements placed on the overall power system, both on the supply and demand sides (Agora Energiewende, 2017b). Alternatives to increase the flexibility of an electricity system include demand response measures, energy storage, and more flexible operation of power plants. In the absence of commercially available and cost-effective large-scale energy storage capacities, it is important for conventional power plants, including geothermal and coal-fired power plants, to increase their operational flexibility. Operational flexibility refers to the extent to which power technologies can respond to the variability in the residual load on different timescales. At the power plant level, operational flexibility is determined by three main features (Gonzalez-Salazar, Kirsten and Prchlik, 2017):

- **Minimum load**: The minimum load is the lowest possible net power a power plant can deliver under stable operating conditions and is measured as a percentage of the nominal load.
- **Ramp rate**: The ramp rate describes how fast a power plant can change its net power output during operation and is measured as a percentage of the nominal load per minute.
- **Start-up time**: The start-up time is the time required to attain stable operation when starting up from standstill and is defined as the time required (in hours) from starting plant operations to reach the minimum load.

Historically, conventional power plants have been designed to serve electricity demand patterns characterised by relatively low variability. With an increasing share of variable renewables in power systems, these plants need to be able to react in a more flexible manner. Power plants that were originally designed to provide baseload electricity, such as geothermal and coal-fired ones, increasingly need to operate on a load-following or cyclic basis.

In terms of operational performance related to flexibility, geothermal and coal-based power plants vary across the three main determining features. On average, coal-fired power plants can reach the lowest **minimum load** with 30% of the nominal load; lignite-fired power plants provide the least flexibility, with a minimum load of 50‑60% of the nominal load (Agora Energiewende, 2017b). This is mainly due to combustion stability issues, which are more pronounced in the larger boiler designs present in lignite-fired power plants. Geothermal power plants, on the other hand, can ramp up and down multiple times per day to a minimum of 15% and a maximum of 100% of nominal power (GEA, 2013a).

The normal ramp rate required for dispatch is 15% of the nominal load per minute. Coal-fired power plants have relatively low **ramp rates** due to large component dimensions and a time lag between an increase in fuel input and the turbine response (Agora Energiewende, 2017b). The ramp rate for a geothermal power plant using binary technology and operating in a flexible mode is 30% of the nominal load per minute (GEA, 2015). The ramp rate for single flash plants, on the other hand, is about 2% to 5% of nominal power per minute at typical running loads, although ramping from a cold start generally takes longer (GEA, 2015).

The **start-up** process for coal-fired power plants is quite complex. The hot start-up time[19] for hard-coal- and lignite-fired power plants is 2.5-3 hours and 4-6 hours, respectively. It requires the operation of auxiliary systems, such as cooling pumps, fans, and burners. Additionally, it takes more time for larger components to reach the required temperature levels to begin operation (Agora Energiewende, 2017b). Geothermal power plants are quicker and need on average 1.5 hours for a hot start.

Table 5 summarises the features of geothermal and coal-fired power plants along the three main aspects of operational flexibility.

Table 5: Flexibility characteristics of geothermal and coal-fired power plants (based on Gonzalez-Salazar, Kirsten and Prchlik, 2017a and Agora Energiewende, 2017)

	Geothermal	Coal power (average hard and lignite)	Hard coal fired power plants	Lignite-fired power plants
Minimum load [% P_{Nom}]	15%	30%	25-40%	50-60%
Average ramp rate [% P_{Nom} per min]	5-30%	6%	1.5-4%	1-2%
Hot start-up time [h]	1.5 h	3 h	2.5-3 h	4-6 h

If equipped with the right technological features, **geothermal plants** – even though traditionally considered baseload plants – can ramp up or down quickly, allowing them to adjust to the changing needs of the power system and act as a flexible power source, in addition to providing baseload electricity.[20] Flexible operation involves the venting of steam, at least in cases where flash or dry steam technology is used. The range of ancillary services[21] provided by geothermal technology is broad, but depends on the subsurface resource that supplies it, with wide variations in depth, temperature, chemistry, pressure, permeability, and other characteristics (GEA, 2015).

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[19] If a power plant has been shut down for less than eight hours when it is started up again, this is considered a hot start-up.

[20] At the Puna Geothermal Venture facility in Hawaii, for instance, 8 of the 16 MW of installed capacity are currently used exclusively to provide ancillary services for grid support (GEA, 2013a).

[21] There are six types of ancillary service products: regulation up, regulation down, load following up, load following down, spinning reserve, and non-spinning reserve.

Building a geothermal plant so that it can offer a full suite of flexibility services does not impose any limitations on the plant operating in baseload mode, and the incremental cost required to enable these flexible dispatch attributes is very small (GEA, 2013a). However, additional maintenance may be required for a plant operating in a more flexible manner, depending on the technology used. Operating a binary geothermal plant in a flexible mode does not increase the OPEX, because the nominal flow of hot fluid in the system can be circulated when only a partial load is required. Thus, there is no cost for the unused geothermal fluid, or "fuel", of a geothermal plant (GEA, 2013a). More flexible operation of a flash or a dry steam plant, on the other hand, may incur slightly higher OPEX, since ramping and load following involves steam venting or bypassing the turbine. Furthermore, experiences with more flexible operation of dry steam plants have shown increased O&M problems with the equipment and systems (GEA, 2015).

In the end, for most geothermal power plants, flexibility is an economic issue rather than a technical one. While it is technically possible for a geothermal power plant to provide ancillary services for short- and long-term flexibility, this is often not economically feasible under traditional PPAs. To date, the changing power markets have mostly ignored or undervalued geothermal power and its ability to be both a reliable and flexible resource that can address the challenges faced by the integration of variable renewables. However, with well-structured and appropriately priced contracts, geothermal plants can provide flexibility in an economically efficient manner. The terms for the plants need to be modified so that they are compensated not only for operating in baseload mode, but also for providing reserve capacity. An industry survey among geothermal developers conducted by the Geothermal Energy Association found that the main reason most geothermal power plants operate mainly in baseload mode is the lack of economic incentives to ensure an acceptable return on investment for geothermal plants operating in a flexible mode (GEA, 2015).

Thus, future contracts need to encourage geothermal operators to offer more flexibility, enabling them to compete with other intermediate load power plants. Traditionally, ancillary services have been provided by fuel-based plants such as natural gas-fired ones. In many cases, the associated contracts are highly priced due to spot market gas purchases. Geothermal energy, combined with adequate PPAs, can offer a more economical alternative, due to the absence of fuel price volatility. Edmunds and Sotorrio (2015) have identified several aspects that should be incorporated into future geothermal power contracts to encourage flexibility:

- When geothermal plants are intended to be operated in a flexible, load-following mode, contracts should be negotiated to include payment schedules that define the price of power in response to a dispatch signal transmitted by the independent system operator or other load-serving entity.
- To increase the ability of geothermal plants to regulate frequency (i.e. by ramping the power generation up or down over a period of a few minutes), power pricing in future contracts should be negotiated to include payments specifically for frequency regulation services.
- Utilities could buy capacity from a geothermal plant and then purchase electricity as they regulate its output, within the plant's technical limits. Flexible contracts with pricing structures that account for geothermal technology's capital structure would enable flexible geothermal power to compete with other energy sources such as natural gas.
- Geothermal power plants could use storage technologies to store electricity and release it as needed, instead of constantly feeding electricity directly into the grid.

If contracting mechanisms are adapted accordingly, based on the abovementioned points, experiences have demonstrated that geothermal units can be built or retrofitted to provide ancillary services and serve as a flexible generation source.

As in the case of geothermal power, it is widely assumed that **coal-fired power plants** cannot be operated flexibly and adapt to varying system loads without costly redesign measures or losses (Agora Energiewende, 2017b). However, there are numerous technical options for increasing the flexibility of coal-fired power plants originally designed for baseload power generation. Furthermore, effective market incentives such as intraday electricity markets have been introduced in order to remunerate the provision of flexibility. In some countries,

including Germany and Denmark, hard-coal-fired power plants and, to some extent, lignite-fired power plants operate with significant flexibility to balance the increasing presence of variable renewables in the system (Agora Energiewende, 2017b). Usually, improving the technical flexibility of a plant does not impair its efficiency, but it does have an impact on the plant's lifetime and the associated capital and operational costs (Gonzalez-Salazar, Kirsten and Prchlik, 2017). Flexible operation, including high ramp rates and multiple start-ups, puts more strain on components and results in increased forced outage rates and reduced power plant lifetime. Thick-walled components are especially affected by thermal stress, which can result from high ramp rates and numerous start-ups. Huge load changes of over 50% of nominal power and cold starts put the highest strain on these components. A dynamic operation mode increases the accumulated annual fatigue life consumption by a factor of 8 compared to a baseline operation mode (Agora Energiewende, 2017b). As a consequence, frequent physical component checks, e.g. through X-ray examination, crack testing, or micro-structure examination, are necessary to verify component health. Additionally, more cycling and ramping results in degraded performance and higher emissions (e.g. of carbon dioxide (CO_2), nitrogen and nitrous oxides (NO_x), and sulphur dioxide (SO_2)) over time and can lead to an increase of approx. 2‑5% of total variable OPEX (Agora Energiewende, 2017; Gonzalez-Salazar, Kirsten, and Prchlik, 2017). Thus, increasing the flexibility of coal-fired power plants, while technically possible, has lifetime impacts and generates additional costs.

In conclusion, the possibility to combine baseload and flexible operation makes geothermal plants, especially binary systems, an ideal candidate to fill several roles historically taken by carbon-intensive fossil fuels, such as baseload, regulation, load-following, and reserve functions. While coal power generation also offers the possibility to provide ancillary services to some extent, this leads to significant reduction of the plant's lifetime and an increase in O&M costs.

Sector stability

The planned expansion of geothermal power in Kenya provides more flexibility for sector development, as geothermal generation is more decentralised and can expand in line with the sector's needs. The implementation of a large-scale project like the Lamu plant might put sector stability, affordability, and sustainability at risk—for example, in the case of late transmission line delivery, resulting penalty payments, or major blackouts, affecting the security of supply.

A key task for electricity sector planners is to ensure that the power system stays in balance in the case of sudden loss of a generating unit. This section analyses the influence of existing and planned geothermal and coal-based power generation on electricity **sector stability** in Kenya. Worldwide, the diversification of the electricity mix is considered a good practice, as it reduces the dependency of a power system on individual power plants, thus ensuring grid stability and safety (GMC, 2017).

As both geothermal and coal power generation are considered mainly for baseload electricity supply in Kenya, it is worth analysing the detailed expansion planning by comparing the committed generation projects for both technologies in the period 2017-2024. Eighteen **geothermal power plants** have been commissioned, with an average capacity of 70 MW, ranging in size from 10 MW (Orpower IV Plant 1) to 158 MW (Olkaria V) (Republic of Kenya, 2018). In contrast, one 981 MW **coal-fired power plant** is planned, with three units of 327 MW capacity each. While the total installed capacity of committed projects for both technologies is similar—1,299 MW of geothermal power compared to 981 MW of coal power—, geothermal power generation is more decentralised and divided among multiple power plants. The fact that geothermal power is sourced from numerous relatively small power plants allows electricity sector planners to respond with greater flexibility to unforeseen fluctuations in demand. Adding a power plant the size of the Lamu plant reduces room for flexibility. Therefore, given the great uncertainty in future peak demand, Kenya needs to adopt a flexible resource plan that permits the addition of new capacity in smaller increments. Assuming an 85% capacity factor as indicated by the project developers, the 981 MW Lamu coal project is expected to produce around 7,818 Gigawatt-hours (GWh) per year, corresponding to more than 75% of the total electricity consumed in Kenya in 2016 (AFDB,

2016; KPLC, 2017). By comparison, the annual growth in electricity demand has been below 6% over the last three financial years, and the total growth of demand between 2013 and 2018 was 26.2% (KPLC, 2017). This means that even with the current annual growth rate in electricity demand, the Lamu coal plant will produce around 50% of the total electricity consumed when it is commissioned in 2024. Given this, and taking into account the existing project pipeline, a stand-alone large-scale plant like the Lamu coal power plant is not required in the medium term, which is indicated by the extremely low capacity factors predicted for coal power[22] in the 2017-2037 LCPDP (Republic of Kenya, 2018). The Lamu coal power plant involves a number of other risks mainly linked to the size of the plant in relation to the overall installed generation capacity, which could ultimately lead to destabilisation of the sector:

- The risk of massive **blackouts** in the case of emergencies at the plant or transmission line level: Exposing the electricity sector to this risk contradicts the so-called "N-1 criterion", which states that the network must remain in operation in the case where any unit, particularly the biggest one, is disconnected (GMC, 2017).
- A **delay in the installation of transmission lines:** If the electricity sector relies predominantly on one power plant, a postponement of the connection of that power plant to the grid has an immediate impact on the entire economy. The experience in Kenya shows that the exact timing for the commissioning of transmission lines cannot be determined with certainty, as in the case of the Loyangalani line for the evacuation of the Lake Turkana wind farm, which was delayed due to various issues, including demands for compensation from landowners (Amalda, 2018).
- The addition of a 981 MW coal power plant in 2024 will aggravate the projected **supply-demand imbalance,** as the surplus margin will likely exceed 1,500 MW, with 32% of the electricity generated representing excess energy (Republic of Kenya, 2018). This would have, among other things, an influence on the electricity tariffs.
- The prospect of a coal-fired power station of this size may deter investment in this sector, as investors may perceive the risk of investing in additional (on-grid) generation projects to be too high, given the uncertain demand growth.

Expansion of geothermal power in Kenya provides electricity sector planners with more flexibility than the introduction of a coal power plant. Furthermore, the risks associated with the development of the Lamu coal power plant are much less applicable to geothermal projects, as they are larger in number but smaller in size. Nonetheless, the current and expected future dominance of geothermal power in the Olkaria field should be closely monitored in terms of security of supply, e.g. with regard to a potential decrease in the productivity of the geothermal source or difficulties in evacuating the power to the grid. To mitigate this risk, the development of new geothermal resources in other geothermal fields can be encouraged. Even with higher than expected demand growth in the future, the planned coal-fired power plant in Lamu seems to be oversized and may contribute to the destabilisation of the sector in the short to medium term.

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[22] The average capacity factor of coal in Kenya in the period 2019-2024 is expected to be 1.3%, 15.16%, and 6.84% for the Fixed System, Optimised, and Fixed Medium-Term scenarios, respectively (Republic of Kenya, 2018).

4 Impacts on national development objectives

Policies that primarily target the electricity sector can positively contribute the achievement of other sustainable development-related objectives that are important to society, such as food security, human health, energy access and security, employment creation, and environmental services (IPCC, 2014). In this context, the benefits of policies that go beyond those directly related to their original purpose are labelled "co-benefits" or sustainable development impacts. Co-benefits are increasingly considered in international policy making and are gaining political and economic momentum. The integration of multiple objectives in policies can strengthen the support for such policies and increase the cost-effectiveness of their implementation. This section qualitatively and quantitively analyses the economic, health-related, and environmental impacts of geothermal and coal-based power generation.

Box 1: The Economic Impact Model for Electricity Supply (EIM-ES)

The EIM-ES is a spreadsheet-based economic model used to estimate the *domestic* employment impacts of investments in new electricity generation capacity within a country. The model covers all relevant electricity generation technologies – both low carbon and fossil fuel-based plants – in order to provide an assessment of employment creation under different future pathways for the development of the electricity sector. The technology coverage is simple to adjust within the model and can be tailored to the country of interest.

The analysis is based on investment cost data, disaggregated, where possible, into its component parts for new electricity generation capacity. Based on input data and underlying assumptions, the model calculates the share of each investment that is spent domestically and the share of that domestic investment that is directed to the labour market. The direct employment impact is then estimated by dividing the domestic labour market investment by an average annual salary that is representative for the work carried out. The model apportions the direct jobs created over time based on assumptions related to the duration of the various tasks and services. For example, construction jobs may last for 2 to 5 years, depending on the technology. Jobs created to provide O&M services typically cover a much longer period of time, tied to the expected lifetime of the asset.
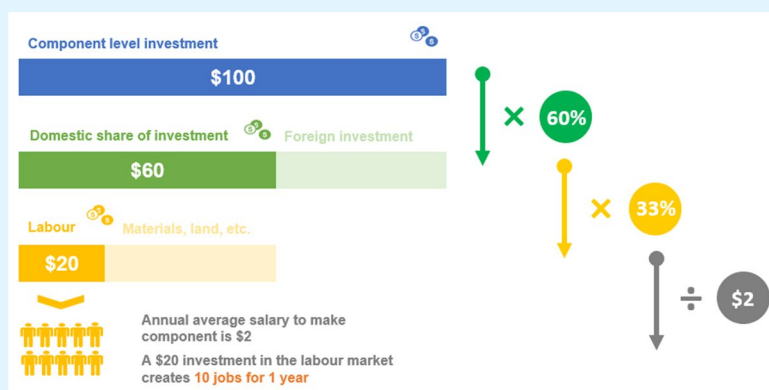
Direct employment creation over time is the key focus of the model (e.g. for manufacturing equipment, construction of plants, professional services, etc.). In addition, the tool calculates indirect and induced employment impacts by drawing on input-output tables for the economy. Input-output tables reflect the interdependencies of sectors across the economy, based on national statistics, and provide an order of magnitude of the wider economic impacts of investment in electricity generation. *Indirect* jobs refer to those created in secondary sectors upstream in the supply chain (e.g. in the metallurgical or mining industries). *Induced* jobs are created across all economic sectors as a result of an investment stimulus (e.g. the salaries of those that directly and indirectly benefit from the investments are spent on other, unrelated activities, such as housing, restaurants, healthcare, etc.).

The level of accuracy of the analysis depends somewhat on the quality of data inputs and the extent to which they reflect the country-specific context. Where country-specific data points are either missing or unreliable, we can draw on regional and international information, adjusted, where relevant, to the target country. The model is designed to enable sensitivity analysis on key data inputs to evaluate the extent to which they influence the final results.

4.1. Employment and investment impacts

Investment in electricity generation results in the immediate creation of direct and indirect employment opportunities, as well as wider economic effects, during a project's construction and operation phases. In this section, the *Economic Impact Model for Electricity Supply (EIM-ES)* from the *Ambition to Action* project [23] is used to estimate the impact of geothermal and coal-based electricity generation on domestic employment creation and the triggering of investment.

The EIM-ES is used to estimate the impact of investments in new electricity generation capacity on domestic employment in Kenya, with a focus on geothermal and coal-fired power plants. The two technologies are compared in terms of their impact on employment creation and investments triggered domestically. This is done for two different expansion scenarios, which are both simulated under the 2017-2037 LCPDP's reference demand forecast scenario. The reference demand forecast scenario is the base case scenario, with development projected from historical growth and estimated peak demand for the period 2017-2037 ranging from 1,754 MW to 6,638 MW (Republic of Kenya, 2018). The Lahmeyer International Short-term Optimisation and Long-term Expansion (LIPS-OP/XP) software, which was used to develop the 2017-2037 LCPDP, is employed in this study to simulate and compare the following two generation expansion scenarios:

1. Fixed Medium-Term Case (as per the 2017-2037 LCPDP [24]), referred to as '**Reference Case'**

The case consists of the existing plants, committed additions, and retirements over the planning period. It assumes a fixed system that comprises existing plants and proposed projects by the various power sector players, including the private sector, over the entire period. The three units of the Lamu coal power plant, each with 327 MW of net capacity, are considered obligatory candidates, with 2024 as a fixed commercial operation date (COD) (Republic of Kenya, 2018). However, this scenario clearly shows that the Lamu coal power plant will be grossly underutilised, with an average capacity factor of only 6.84%, while geothermal plants have an average capacity factor of 74% (Republic of Kenya, 2018). The total installed capacity, divided by energy source, for the Reference Case during the defined period is depicted in Figure 5.

Figure 5 Installed capacity – Fixed Medium-Term Case – reference forecast (based on *LIPS-OP/XP with inputs from the 2017 – 2037 LCPDP and EPRA's LCPDP planning team*)

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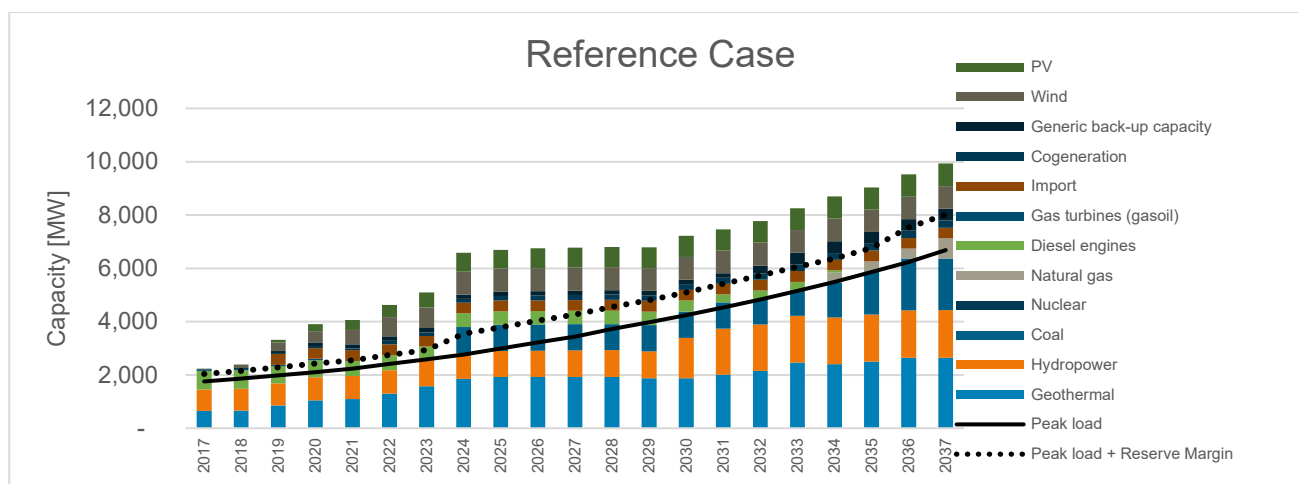
[23] The co-benefit tools of the Ambition to Action project have been developed by NewClimate Institute and Energy Research Centre of the Netherlands (ECN part of TNO) to quantitatively estimate the impacts of energy sector pathways on various socio-economic indicators. These tools and their methodologies were developed in collaboration with national experts and validated by national governmental and non-governmental stakeholders.

[24] This expansion sequence is broadly in line with the Fixed Medium-Term Case under a reference forecast scenario from the 2017 – 2037 LCPDP, with minor adjustments to the CODs for geothermal plants based on the advice of the LCPDP planning team after the release of the latest LCPDP.

2. Adjusted Optimised Generation Expansion Case, referred to as '**Optimised Case Adj.**'

This case is based on the 'Optimised Generation Expansion Case' from the 2017-2037 LCPDP, which was developed assuming that projects beyond 2023, including the Lamu coal power plant, are not considered as obligatory candidates, in order to minimise the generation surpluses seen in the Reference Case. The adjusted version of this case was developed during a training workshop with EPRA's LCPDP planning team and consultants from Tractebel-Engie,[25] as well as NewClimate Institute, in May 2019, using LIPS-OP/XP software. The training exercise involved modifying/adding several expansion candidates, as follows:

- Menengai IV 100 MW geothermal plant defined as binary (not must-run); earliest COD in 2036
- Additional generic geothermal plant: 300 MW binary system; earliest COD in 2036
- Additional generic geothermal plant: 100 MW binary system; earliest COD in 2036
- Additional generic backup unit: 280 MW; earliest COD in 2036
- Additional generic backup unit: 70 MW; earliest COD in 2036

When optimising the generation expansion through LIPS-OP/XP, these candidates compete with those already planned, such as the Lamu coal power plant. The results of the optimisation exercise in terms of total installed capacity, divided by energy source, for the Optimised Case Adj. are depicted in Figure 6.

Figure 6 Installed capacity – Optimised Case Adj. – reference forecast (based on *LIPS-OP/XP and LCPDP training workshop results*)
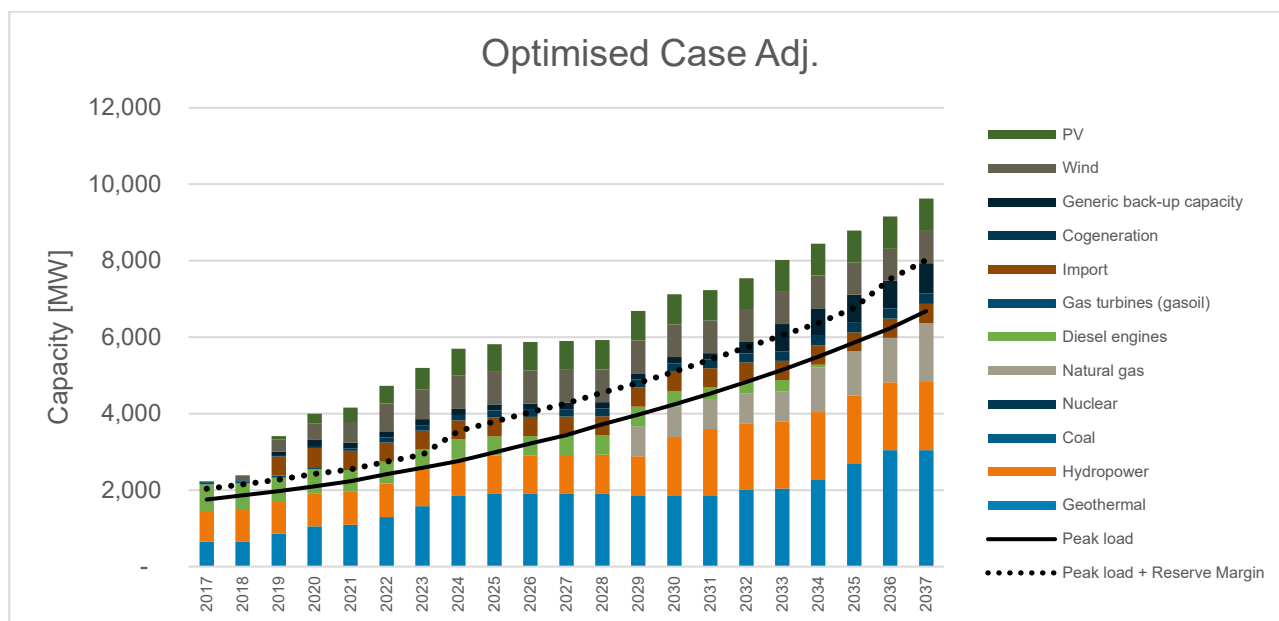
The following comparison is conducted on two levels:

i. The **scenario comparison section** analyses the overall impacts of the Reference Case and the Optimised Case Adj. on domestic employment creation and investment.
ii. The **technology comparison section** assesses the impact of geothermal and coal-based electricity generation on employment creation domestically in each of the two scenarios.

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[25] The LIPS OP/XP software was developed by the engineering and consulting company Lahmeyer International and first applied in Kenya in the scope of the 2015-2035 Power Generation and Transmission Master Plan (PGTMP). Since then, EPRA continues to use the software for the LCPDP process. Lahmeyer International is now operating under the Tractebel brand with a new company name: Tractebel Engineering GmbH.

Scenario comparison

The main difference between the two scenarios is that the Lamu coal power plant is an obligatory (i.e. fixed) candidate in the Reference Case, while it is not in the Optimised Case Adj. Figure 6 shows that, in the Optimised Case Adj., no coal-fired power plant is required in the generation expansion planning if sufficient alternative candidates are provided and expansion sequences are optimised for least-cost options. This is done without incorporating the external costs of production or consumption associated with high-emitting technologies such as coal-fired power plants. If the true costs to society were to be considered, e.g. through the application of a carbon price reflecting the damage GHG emissions cause, technology options like the Lamu coal-fired power plant would be even less competitive. The analysis shows that the Optimised Case Adj. leads to more domestic employment creation and higher investments and, at the same time, is less expensive than the Reference Case, as can be seen in Table 6.

Table 6: Scenario comparison - Employment and investment for the Reference Case and Optimised Case Adj. *(based on EIM-ES and inputs from the 2017-2037 LCPDP & LIPS-OP/XP)*

Impact category	Unit		Reference Case	Optimised Case Adj.
Scenario cost	USD (in millions)		31,361	28,314
Employment creation in 2017-2037 period	Job-years	Total	1,072,656	1,129,363
		Direct	437,065	465,523
Average employment generated per year	Job-years	Total	44,694	47,057
		Direct	18,211	19,397
Investment in 2017-2037 period	USD (in millions)	Total	35,404	36,918
		Direct	18,327	19,078

The total scenario costs for the Reference Case and the Optimised Case Adj. are USD 31.361 billion and USD 28.314 billion, respectively. It is estimated that by implementing the generation expansion planning as suggested in the Optimised Case Adj., a total of 1,129,363 jobs[26] would be created in the period 2017-2037. This includes jobs in the electricity generation sector (direct), secondary sectors (indirect), and across all sectors of the economy as a result of an investment stimulus (induced). The equivalent number for the Reference Case is considerably lower, with a total of 1,072,656 jobs created. The same trend can be observed when assessing the annual impact on employment: according to the analysis, the Optimised Case Adj. would create 1,186 more jobs in the electricity generation sector than the Reference Case and 2,363 more jobs per year when also considering indirect and induced employment creation. For reference, the Kenya National Bureau of Statistics reported 18,934 jobs in the electricity sector in 2018 (Kenya National Bureau of Statistics, 2018). This is in line with the direct employment per year estimated by the EIM-ES (18,211 jobs for the Reference Case and 19,397 for the Optimised Case Adj.). As can be seen in Figure 7, the Optimised Case Adj. is also the most cost-effective scenario with regard to job creation when comparing the number of jobs per unit of investment to the overall scenario costs.

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[26] The term 'jobs' in this study refers to job-years, with one job-year defined as full-time equivalent (FTE) employment for one person for one year.

Figure 7: Scenario comparison: Jobs per unit of investment vs. scenario costs (*based on EIM-ES and inputs from the 2017-2037 LCPDP & LIPS-OP/XP*)
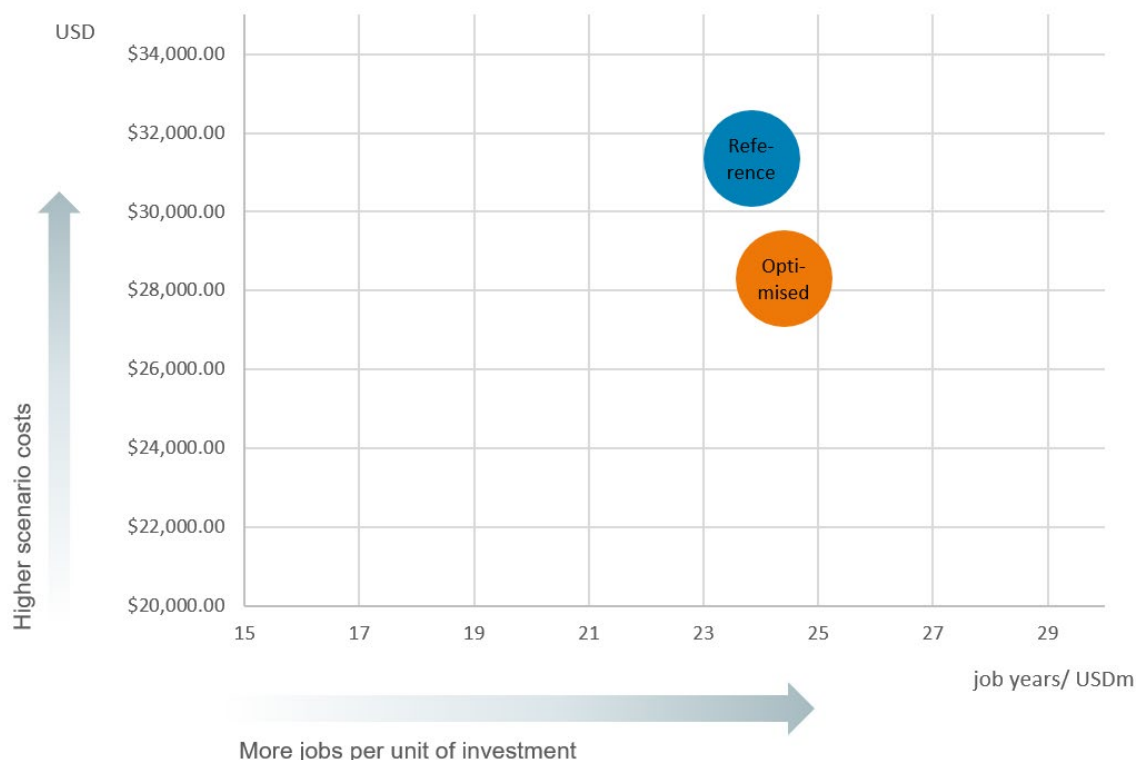
In addition to the impact on employment, the Optimised Case Adj. also triggers more domestic investment (USD 36.918 billion) than the Reference Case (USD 35.404 billion). Furthermore, with regards to the investment made for the construction of the Lamu coal power plant, the National Treasury has approved a remission of value added tax (VAT) related to materials and equipment being imported or purchased locally by the project developer Amu Power Ltd. (The National Treasury, 2015). Considering that the overall investment needed to build the power plant is estimated to be USD 2 billion, this will result in a loss of government tax revenue of hundreds of millions of dollars compared to investments in other technologies (NS Energy, 2018).

Technology comparison

The development of **geothermal power** leads to job creation at various stages in the supply chain. During the construction period, as well as the O&M phase, both direct and indirect jobs are created. The majority of the jobs created are full-time, permanent positions[27]. Local communities benefit from geothermal development; it is estimated that, for every three skilled jobs, one unskilled job—mostly carried out by the local labour force—is created, providing a stable source of employment and adequate wages to people living in economically less-developed areas (AfDB, 2011; KenGen, 2013). Geothermal development has also proven to enhance tourism in the local area, by improving road access to interesting geological structures, such as the Menengai Caldera in Kenya (ADF Menengai Project Appraisal Report, 2011).

In addition, studies have shown that geothermal power generation has a positive impact on female and youth employment among the local population. In compliance with the Kenyan Constitution, GDC strives to ensure a women's labour force participation rate of 30 percent, which can be considered high by small town standards in Kenya and is also above the national average (AfDB, 2011). Furthermore, affected county governments

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[27] Source: http://www.geo-energy.org/geo_basics_employement.aspx (accessed: 19/02/2019)

estimate that geothermal projects have the potential to considerably reduce youth unemployment, given the types of job opportunities created (SEI, 2017).

However, there might be adverse impacts caused by the development of geothermal power, such as impacts on flora and fauna, soil and vegetation contamination, and exposure to high noise levels. Such impacts can affect nearby human settlements and, consequently, the employment situation in that region. Nevertheless, most of the geothermal projects effectively address these issues through mitigation measures (Mwangi-gachau, 2016). At the same time, geothermal projects have the potential to create and improve local secondary industries, e.g. through the provision of steam and water. GDC estimates that the integration of direct use and industrial development into geothermal generation can further lower the unemployment rate. GDC intends to utilise geothermal resources (direct use) to implement socio-economic initiatives in surrounding communities, such as fish farming, improvements to pastureland, milk processing, and grain storage. The creation of benefits for local communities helps ensure social acceptance of the geothermal projects (KenGen, 2013).

In the **coal industry,** jobs are created in coal mining, as well as in the construction and operation phases of coal-fired power plants. As the planned Lamu coal power plant will operate on imported coal, no domestic jobs will be created in the mining sector. With regard to the planned coal power plant in Kitui County, which will run on domestic coal, planning is in too early a stage to draw conclusions on the potential for domestic employment creation through coal mining in the Mui Basin. However, global developments have shown that, as a result of automation, employment in the coal mining industry decreased by 45% between 1987 and 2002 (Diesendorf, 2004). Apart from the potential for employment creation in Kenya's mining industry, studies already foresee several negative impacts of coal mining on the local population in Kitui, including loss of housing and ancillary structures, farmland and grazing land, and key infrastructure (Diakonia, 2014). These losses are likely to further aggravate the employment situation in the region.

Future potential jobs in Kenya's yet to be developed coal industry are largely linked to the Lamu coal power plant, currently scheduled to start operations in 2024[28]. The Lamu project developer indicated that around 40% of the required jobs for construction and 50% of the jobs for O&M will be taken up by foreigners mainly from China (Kurrent Technologies, 2016). This is one of the reasons that in the **Reference Case,** coal power generation leads to considerably lower domestic employment per unit of added output than geothermal power.

Besides a significant share of the anticipated job creation in the coal industry benefiting foreigners, the construction and operation of the Lamu coal power plant will have a number of direct negative impacts on the local economy. For instance, the Department of Fisheries, Livestock, and Cooperative Development found that 5,500 fishermen near the plant site would face a reduction in income, due a decrease in the fish population because of problems such as acid rain or an increase in water temperature at the cooling water discharge point. This development would have a negative impact on employment in the region (AFDB, 2016).

As Figure 8 below shows, geothermal power creates three times more employment per MW of new capacity than coal, with 79 and 25 job-years being created in the geothermal and coal industries, respectively, in the Reference Case. The same order of magnitude can be observed when assessing the impact on short- and long-term employment creation. While geothermal power leads to the creation of 48 job-years for power plant construction per MW of new capacity, coal only leads to 15 job-years. Similarly, geothermal power also generates more employment for O&M tasks per MW of new capacity (31) than coal (10).

As highlighted in the scenario comparison section, no coal-fired power plant is considered for the **Optimised Case Adj.,** as other alternatives are preferred by the least-cost optimisation software. As a result, there is no employment generated in the coal industry in this scenario. By relying on alternative power sources, such as

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[28] On 26 June 2019, a Kenyan tribunal cancelled the environmental licence for the Lamu coal power project. The developers will need to complete a new environmental impact study with community involvement if they wish to proceed, which is likely to cause a delay in the construction of the power plant (IEEFA, 2019a).

additional geothermal power, generic backup units, and natural gas, the Optimised Case Adj. creates more domestic jobs overall in Kenya than the Reference Case, as seen in Table 6.

Figure 8: Technology comparison: Short- and long-term employment creation by scenario and power source *(based on EIM-ES and inputs from the 2017-2037 LCPDP & LIPS-OP/XP)*
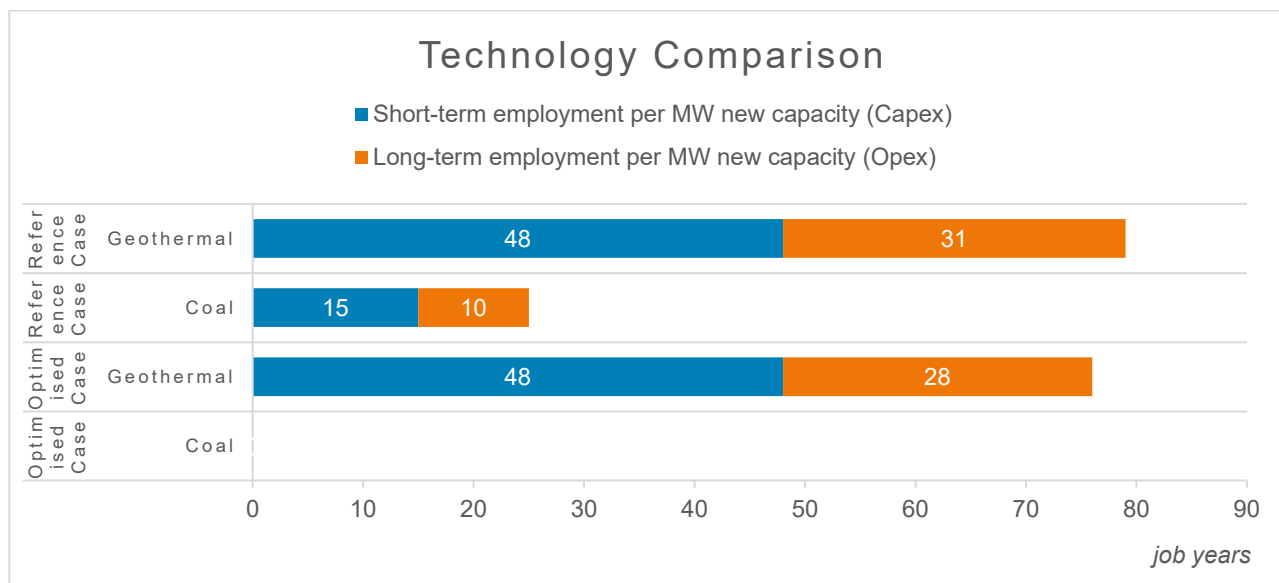
In summary, the Optimised Case Adj. scenario generates more employment opportunities and triggers greater investment at a lower cost, without the addition of coal-based power. Furthermore, while geothermal power has a long history in Kenya and expertise is locally available and sourced, plans for coal-based power generation in Kenya show that the expected employment creation will benefit foreigners to a large extent. The latter has strong implications for Kenya when it comes to local value creation in general and domestic employment creation in particular.

4.2. Air pollution and health impacts

Air pollutant emissions released through energy-related fuel combustion have negative impacts on human health and the environment. In general, air pollution represents the biggest environmental risk to human health in the world, and in 2012, every ninth death was the result of air pollution-related illnesses (WHO, 2016). The energy sector, including both production and use, is the largest source of man-made air pollutant emissions, being responsible for the production of 85% of primary particulate matter and almost all of the SO_2 and NO_x emitted worldwide (IEA, 2016; Watts *et al.*, 2017). GHG emissions and air pollutant emissions often come from the same sources, such as fossil fuel-fired power plants, factories, or vehicles. Consequently, mitigation measures that reduce the use of fossil fuels typically have great potential to also cut emissions of other air pollutants.

In Kenya, overall ambient air pollution led to roughly 4,000 estimated premature deaths in 2013, with associated economic costs of USD 2.2 billion (Roy, 2016). In addition, the vast majority of the Kenyan population was exposed to ambient air concentrations of particulate matter that exceeded the guideline values set by the World Health Organisation (WHO) (Roy, 2016; WHO, 2016).

The operation of the proposed **coal-fired power plants** would further increase these numbers, as the plants would be major sources of air pollution in Kenya, with potentially significant impacts on the surrounding communities and ecosystems, including health impacts, acid rain, and contamination of soil and protected habitats (Myllyvirta and Chuwah, 2017). Secondary pollutants associated with the construction phase, as well as plant maintenance and coal treatment, transport, and storage, also negatively impact the local environment

(Lahmeyer International, 2016). In comparison, **geothermal power plants** do not burn any fuel like fossil-fuel

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Box 2: From air pollution to health impacts

The pollutants considered in the quantitative analysis include primary particulate matter PM$_{2.5}$, as well as SO$_2$ and NO$_x$, which produce secondary particulate matter formed from chemical transformations in the atmosphere. Sulphur dioxide can remain airborne for several days, and nitrogen oxide, half a day, during which time they are able to travel tens or hundreds of kilometres, impacting the health of people both within the country of production and beyond (Jones *et al.*, 2016a). Particles of PM$_{2.5}$ have a diameter of less than 2.5 micrometres and are therefore small enough to enter the airways and alveoli. Thus, the micro-particles can reach the blood and different organs and negatively impact the cardiovascular system or directly cause respiratory illnesses (Cifuentes *et al.*, 2001).

Further physiological changes due to the pollutants include tissue damage and inflammation, plaque formation in arteries, the narrowing of blood vessels, and sometimes even permanent damage to cell DNA (Jones *et al.*, 2016b). These changes can eventually lead to serious events or diseases such as a heart attack, stroke, or cancer.

Overall, the human health impacts caused by exposure to air pollutants are expressed through several morbidity and mortality indicators. The most common health effects reported in relation to ambient air pollution are: a) reduction in life expectancy due to chronic diseases and acute mortality, b) an increase in chronic morbidity due to diseases such as bronchitis or asthma, and c) acute effects on morbidity, including respiratory and cardiovascular hospital admissions, asthma episodes, and restricted activity or work days lost (Markandya and Wilkinson, 2007).

based plants and therefore only release negligible amounts of air pollutants.

Thus, one significant benefit of geothermal energy is its extremely low air pollutant emission rates (see Table 7). Flash and dry steam plants emit about 1-2% of the sulphur dioxide and less than 1% of the nitrogen and nitrous oxide emitted by a coal-fired plant of equal capacity, and binary geothermal plants produce near-zero emissions (GEA, 2013b). The environmental impact of geothermal-based electricity generation is not considered in the following quantitative analysis using the Air Pollution Impact Model for Electricity Supply (AIRPOLIM-ES), since the associated emissions do not include significant amounts of air pollutants, as seen in Table 7.

Table 7: Emissions level by pollutant and energy source (based on GEA, 2013b; MIT, 2006)

[g/KWh]	Geothermal Dry Steam	Geothermal Flash	Geothermal Binary	Coal
CH$_4$	0.0000	0.0000	-	0.11
PM$_{2.5}$	-	-	-	0.27
PM$_{10}$	-	-	-	0.33
SO$_2$	0.0001	0.1588	-	8.50
N$_2$O	0.0000	0.0000	-	0.02
NO$_x$	0.0005	-	-	1.95

In this section, the AIRPOLIM-ES (see Box 3) is used to estimate the health impacts of the proposed new coal capacity in Kenya, compared to a scenario without the coal-fired power plants. This is done for two different scenarios based on the 2017-2037 LCPDP: the Fixed Medium-Term Case under a reference forecast scenario and an Alternative scenario. In contrast to the Reference Case used in Section 3.1, we assume an annual capacity factor for coal of 85%, as indicated by the project developer Amu Power, to show the highest possible impact on human health. Below is a short description of these scenarios; further details can be found in the Annex. As stated above, the impacts of geothermal-based electricity generation are not considered in the quantitative analysis, since its emissions do not include significant amounts of air pollutants.

1. **2017-2037 LCPDP Fixed Medium-Term Case under a reference forecast scenario,** referred to as '**Reference Case_high coal**'

   This scenario under the reference forecast includes a total coal-based capacity of 1941 MW, with the power plants in Lamu and Kitui starting operations between 2024 and 2036. The assumed lifetime of each of the coal-fired power plants is 30 years, with an average assumed capacity factor of 85 percent.

2. **Alternative scenario,** referred to as '**Alternative Case**'

   The alternative scenario was not directly modelled under the 2017-2037 LCPDP, but was highlighted by EPRA in the recommendations section and further outlined in a newspaper article discussing these recommendations (Kamau, 2018; Republic of Kenya, 2018a, p.156). In this scenario, the Kitui power plant is not built and the total capacity of the coal-fired power plant in Lamu is reduced to 450 MW, and its operations start in 2034, instead of 2024.

Box 3: The Air Pollution Impact Model for Electricity Supply (AIRPOLIM-ES)

The AIRPOLIM-ES is a spreadsheet-based model that uses an accessible methodology for quantifying the health impacts of air pollution from different sources of electricity generation and other fuel combustion. The first version of this tool focuses on electricity generation from coal- and gas-fired power plants. It calculates the impacts on mortality from four adulthood diseases: lung cancer, chronic obstructive pulmonary disease (COPD), ischemic heart disease, and strokes, the prevalence of which is increased through exposure to air pollution.

The health impact assessment is based on emissions of particulate matter ($PM_{2.5}$), NO_X, and SO_2. The model estimates the annual and lifetime electricity generation (GWh) for each plant, as well as the corresponding emissions of air pollutants using plant-specific data and emission factors. Depending on the type of emissions control equipment installed, the model multiplies the estimated fuel consumption with the corresponding country-specific emission factor. Where more detailed information is available, plant-specific emission factors can be entered into the model to improve accuracy.
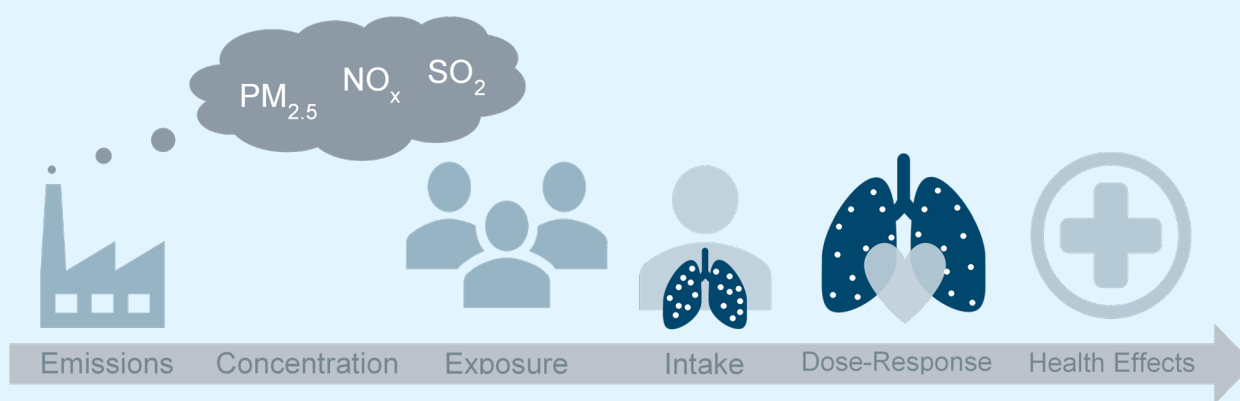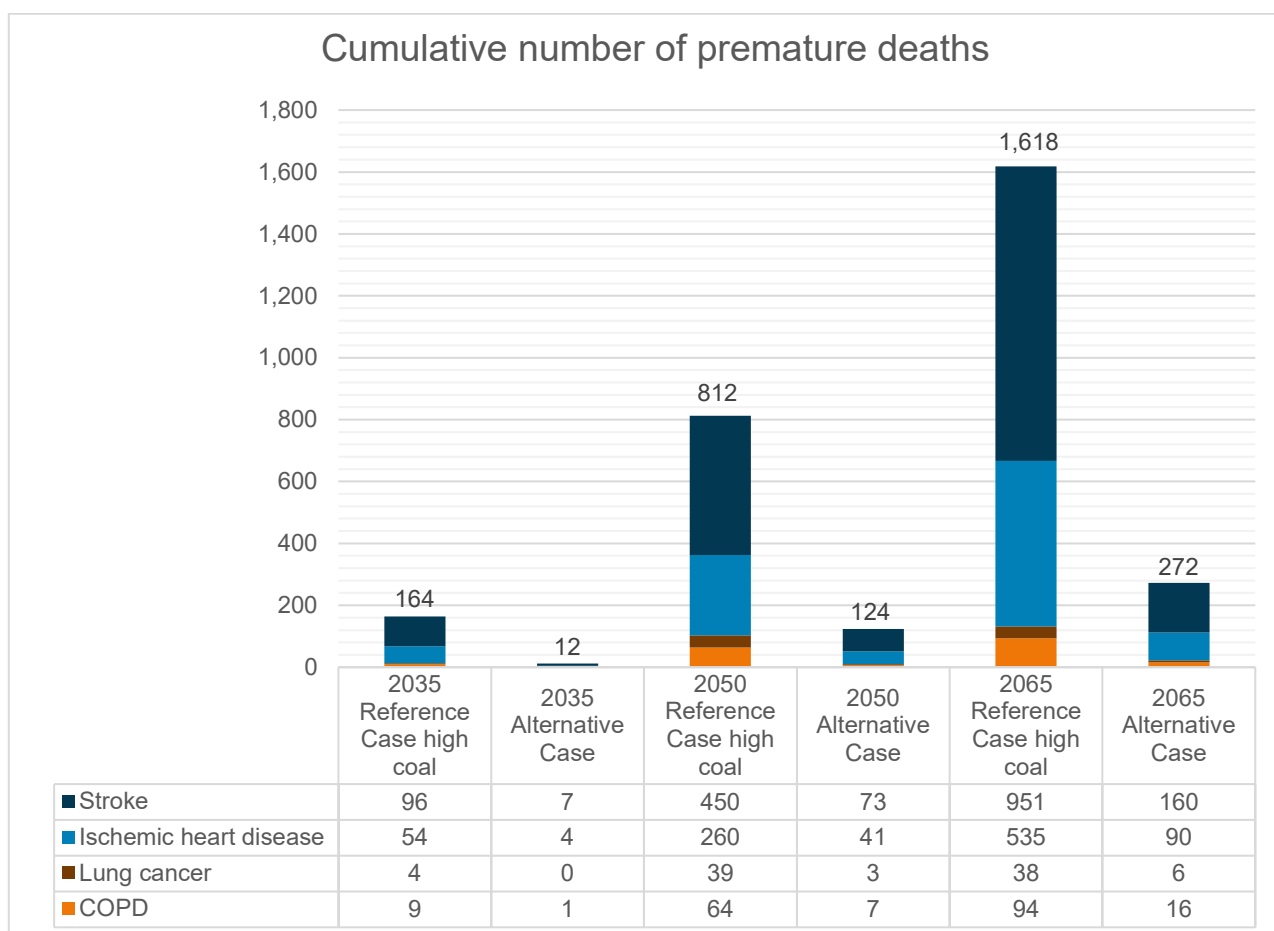

The exposed population living within four distance bands (0–100 km, 100–500 km, 500–1,000 km, and 1,000–3,300 km) from each power plant is estimated using open-source Geographic Information System (GIS) software, also considering population growth. The model uses the intake fraction concept to estimate the change in PM2.5 concentration in the ambient air based on the calculated pollutant emissions. Intake fractions indicate the grams of $PM_{2.5}$ inhaled per ton of $PM_{2.5}$, NO_X, and SO_2 emissions. These fractions - drawn from literature based on air dispersion modelling – enable estimation of the change in $PM_{2.5}$ concentration. In order to estimate the intake fractions for the three pollutants, the model applies coefficients from a widely cited study from Zhou et al. (2006). One limitation of this approach is that the coefficients do not account for location-specific characteristics such as stack-height or meteorological conditions; nevertheless, Zhou et al. show that population exposure by distance is by far the most significant determinant of the level of intake of pollutants.

To calculate the increased mortality risk per additional ton of pollutant emissions, the estimated change in $PM_{2.5}$ concentration is multiplied with the respective concentration-response function. Concentration-response functions are estimated based on long-term medical cohort studies and indicate the increase in cause-specific mortalities per 10 microgrammes per cubic metre increase in $PM_{2.5}$. The Global Burden of Disease project provides mortality rates by disease for different age groups at the country level. The model obtains age-weighted mortality rates by disease using the share of the country's population in each age class. The risk estimates, age-weighted mortality rates, and exposed population are combined to calculate the number of premature deaths per ton of pollutant for each cause of death. Finally, these numbers are multiplied with the estimated pollutant emissions to obtain the total premature deaths per pollutant and cause for each power plant. Premature death refers to deaths that are attributed to exposure to a risk factor, e.g. air pollution, and could be delayed if the risk factor was eliminated.

Figure 9 gives an overview of the estimated cumulative number of premature deaths per scenario and the cause of death at different points in time, estimating only the impacts on the Kenyan population. The leading cause of deaths in any of the scenarios is stroke, followed by ischemic heart disease, chronic obstructive pulmonary disease, and lung cancer. Up to 2065, roughly 1,620 people would die prematurely in Kenya if the

Reference Case_high coal was implemented, including the operation of both coal-fired power plants in Lamu and Kitui. For the same timeframe, approximately 270 premature deaths would occur in the Alternative Case. However, these are conservative figures, since a whole range of indicators – including all morbidity-related factors, health impacts from other pollutants and in other countries, effects on children, and workdays lost – were not included in the analysis. Furthermore, the calculations show that the number of premature deaths substantially increases with population growth, as the amount of pollutants inhaled increases due to more people being exposed, i.e. living in the distance bands around the coal-fired power plants. This means that with every additional year of operation, the health impact of the coal power plants will increase compared to the previous year, as long as the population continues to grow. Considering that one of the objectives of Vision 2030 is to improve the health situation in Kenya, pursuing the construction and operation of the coal-fired power plants clearly works against this goal.

Figure 9: Cumulated number of premature deaths per scenario and cause of death *(based on AIRPOLIM-ES and inputs from the 2017-2037 LCPDP)*

Cumulative number of premature deaths

	2035 Reference Case high coal	2035 Alternative Case	2050 Reference Case high coal	2050 Alternative Case	2065 Reference Case high coal	2065 Alternative Case
■ Stroke	96	7	450	73	951	160
■ Ischemic heart disease	54	4	260	41	535	90
■ Lung cancer	4	0	39	3	38	6
■ COPD	9	1	64	7	94	16

4.3. Climate change impacts

The generation of electricity causes damage not only to human health, but also to ecosystems and the natural environment, as it continues to rely to a large extent on the use of fossil fuels worldwide. While all forms of electricity generation have an environmental impact, the strength of the effect differs based on technology. The combustion of fossil fuels for electricity generation typically produces high amounts of CO_2 emissions. Electricity generation from renewable sources such as solar, wind, and geothermal energy, on the other hand, produces less emissions.

Even though **geothermal power** is a renewable energy source, geothermal-based electricity generation does result in some GHG emissions. These emissions are generally minor in comparison to those from traditional non-renewable baseload generation facilities, such as coal-fired power plants, since there is no combustion process involved. The main GHG emitted by geothermal operations is CO_2, along with a smaller amount of hydrogen sulphide. The exact level and composition of GHG emissions arising from geothermal power generation is contingent upon the spatial location, composition of the reservoir fluid, and technology used (ESMAP, 2016).

Flash and dry steam plants are typically based on open-loop systems in which gases are released into the air. A field survey of geothermal power plants operating in 2001 found a variation in the direct CO_2 emission rates, from 4 to 740 grams of carbon dioxide per kilowatt hour (gCO_2/kWh). According to this study, the global average estimate for operational GHG emissions from geothermal power production is 122 gCO_2/ kWh (Bertani and Thain, 2002). In binary cycle power plants, on the other hand, which typically rely on closed-loop systems, operational CO_2 emissions are nearly zero, as only water vapour is emitted into the atmosphere (IPCC, 2011).

In Kenya, two thirds of the geothermal plants are owned and operated by KenGen and use flash steam technology. However, a growing number of IPPs, who operate the remaining one-third of the plants, use binary steam cycle technology for their plants.[29]

Coal-based generation is a highly resource-intensive means of electricity production. According to performance data in the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC), direct operational emissions from a coal power plant vary between 670 and 870 gCO_2/kWh (Schloemer *et al.*, 2014).

In Kenya, the Lamu coal plant is planned to operate with General Electric's (GE) ultra-super critical technology and imported coal from South Africa.[30] South Africa extracts sub-bituminous, bituminous, and anthracite coal (Department of Energy, 2018). The PPA between Kenya Power and Amu Power is silent on the type of coal that will be used in the plant. Assuming ultra-super critical technology, the emission factor can be estimated to be between 94,600 and 98,300 $kgCO_2$/terajoule (TJ) (Eggleston et al., 2006).

In order to calculate the emissions of different technologies and estimate the climate change impact of a system's technology mix, a simple excel tool can be used.

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[29] Source: https://energysiren.co.ke/2018/12/17/all-you-need-to-know-about-kenyas-geothermal-power-plants/ (accessed: 20/08/2019).

[30] Source: https://www.busiweek.com/1050mw-lamu-power-project-to-use-ultra-super-technology/ (accessed: 20/08/2019).

Box 4: The emissions calculation tool

The emissions calculation tool is an Excel-based tool to calculate the emissions impact of different technologies, as well as at a system level, based on a specific technology mix. Main inputs for the tool include data on final electricity generation per installed technology and technology parameters (for example, sub- or super-critical technology for coal generation). Based on these inputs, the tool calculates emission factors (in $kgCO_2/GWh$) and emission trends per technology. The emission trends can be visualised in the context of total national emissions from all sectors or in the context of Kenya's national climate change target, as communicated in its NDC.

Easy-to-use reporting tool for sector emissions

Visualise trends and link to national climate change targets

Consider additional options for mitigation of climate change

To facilitate the calculation of the emissions in different LCPDP generation expansion scenarios, as well as potential costs in case a carbon price is introduced, the emissions calculation tool was integrated into the LIPS-OP/XP planning tool currently being used in the LCPDP process. For this purpose, the LIPS interface was adjusted to include fuel specific emission factors (in tonnes of carbon dioxide per terajoule (tCO_2/TJ)) as well as a provision for an annual carbon price (USD/t). Plant specific emission costs can thus be considered as an objective function of the operational dispatch and expansion plan optimisation. Annual emissions (in tCO_2 and tCO_2/GWh) and emissions-related costs per power plant, power plant group, or expansion scenario can be viewed in the LIPS results file.

To assess the climate change impact of future generation expansion scenarios in Kenya based on geothermal and coal, it is convenient to compare the Reference Case and the Optimised Case Adj., the scenarios described in Section 3.1.[31] While the Reference Case foresees the commissioning of the Lamu coal plant in 2024, the Optimised Case Adj. offers alternatives to the coal plant, such as geothermal and generic backup units, which displace coal in the generation expansion optimisation.

An analysis of both scenarios in terms of CO_2 emissions shows that total system emissions increase from 1.4 megatons (Mt) of CO_2 in 2017 to 6.3 $MtCO_2$ in 2037 in the Reference Case, i.e. emissions more than quadruple in twenty years. In the Optimised Case Adj., emissions increase from 1.4 $MtCO_2$ in 2017 to 3.5 $MtCO_2$ in 2037. When looking at the total accumulated emissions over twenty years, a system without coal emits 18% less CO_2 than a system in which a coal plant is being commissioned in 2024 (see Table 8).

Table 8: Total emissions (in $MtCO_2$) in the period 2017-2037 *(based on emissions calculation tool and inputs from the 2017-2037 LCPDP)*

Total emissions (in $MtCO_2$)	2017	2037	Increase in % (2017-2037)	Accumulated emissions (2017-2037)
Reference Case	1.43	6.27	337%	48.63
Optimised Case Adj.	1.43	3.53	146%	39.68

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[31] In line with Section 3.1, the Reference Case used for the emissions calculations assumes an average capacity factor for coal of 6.84% and for geothermal of 74%, as foreseen in the 2017-2037 LCPDP.

While there is currently no carbon pricing policy in place either in Kenya or at a global level, different institutions, including the World Bank, recommend applying a shadow carbon price to emissions that ranges between USD 40 and 80 per ton of CO_2 equivalent in 2020 and rises to USD 50-100 per ton of CO_2 equivalent by 2030, increasing by 2.25% per year beyond 2030 (World Bank, 2017). Taking the lower and upper ends of the ranges as minimum and maximum values for calculating the costs of emissions in Kenya, the application of a minimum carbon price would lead to an increase in emission costs from USD 53.5 million in 2017 to USD 366 million in 2037 in the Reference Case. In the Optimised Case Adj., emission costs would increase from USD 53.5 million in 2017 to USD 206 million in 2037, a savings of USD 160 million per year by 2037, as compared to the Reference Case. If applying a high carbon price, costs would increase from USD 107 million in both cases in 2017 to USD 732 million in the Reference Case and USD 412 million in the Optimised Case Adj. in 2037, respectively. This would translate to savings of USD 320 million per year by 2037 in the Optimised Case Adj.

Table 9 Emissions costs (in million USD) for a varying carbon price per scenario (based on emissions calculation tool and input from the 2017-2037 LCPDP)

Emissions costs (in million USD)	Low carbon price (USD 40 & 50 per tCO2 equivalent in 2020 and 2030, respectively)			High carbon price (USD 80 & 100 per tCO2 equivalent in 2020 and 2030, respectively)		
	2017	2037	Total over 20 years	2017	2037	Total over 20 years
Reference Case	53.5	366.0	2,454.5	107.1	732.1	4,909.0
Optimised Case Adj.	53.5	206.1	1,958.8	107.1	412.2	3,917.7

Apart from other socio-economic costs related to climate change impacts, such as increased expenditure on healthcare, the emissions from coal-based electricity generation could place an additional burden on public spending as soon as a carbon price is introduced to internalise the negative effects of emission-intensive activities. In the case of Kenya, a generation expansion scenario that forgoes the use of coal for power generation in the future could help the country save between USD 495.6 and 991.3 million over 20 years, as compared to a scenario in which the Lamu coal plant is being built.

5 Take-aways for electricity sector planners

This report shows that Kenya and its citizens would benefit in numerous ways from strengthening the geothermal industry and further expanding geothermal power, while cancelling the plans to extract coal resources domestically and build coal-fired power plants.

The following key points should be considered by electricity sector planners and decision-makers when determining the most suitable mix of electricity generation technologies in Kenya:

1. **Coal generation will be a burden, rather than an asset, to the electricity supply sector.**
The decision to develop the Lamu coal power plant was based on very high load growth forecasts in the 2011-2031 LCPDP. However, electricity demand forecasts decreased considerably in the following years (see PGTMP and 2017-2037 LCPDP), due in part to lower than anticipated economic growth rates and delays in the Vision 2030 flagship projects. According to the Fixed System and Fixed Medium-Term scenarios in the 2017-2037 LCPDP, the Lamu coal power plant will start operations in 2024 but will be grossly underutilised, with average capacity factors of 1.3% and 6.84% for the Fixed System and Fixed Medium-Term cases, respectively. The results of the Optimised Case Adj., which is based on the 2017-2037 LCPDP Optimised scenario, clearly confirm that no coal power plant is needed if sufficient alternative candidates are provided and expansion sequences are optimised for least-cost options without fixing the CODs of particular power plants. This analysis does not include incorporation of the external costs of production or consumption associated with high-emitting technologies such as coal-fired power plants, which would make coal even less attractive.

While the above point shows that coal is not needed to secure electricity supply, the following points indicate that the choice of geothermal over coal-based power to meet future electricity demand would have many positive effects and contribute to the achievement of other sustainable development objectives:

2. **Coal power is expensive and will increase electricity prices.**
While capital expenditure for the construction of a coal power plant may be predictable, the variable operational costs, driven primarily by the fuel costs, can significantly increase generation costs. Given the high overall investment costs and the gradually worsening financing options for coal power, the profitability of a coal power project depends to a large extent on a high capacity factor. However, the nature of the PPA for the Lamu coal power plant, including the take-or-pay clause and capacity charges, and the low predicted capacity factor for the plant could cause the price of Lamu's electricity to be 3 to 10 times higher than the original projections of the project developer. The LCOE of the system would rise rapidly to USD 16 cents per kilowatt hour by 2024, mainly due to an aggravated supply-demand imbalance. In addition, the scenario comparison conducted in this study reveals that the Optimised Case Adj., with no coal power included, is less expensive than the Reference Case, which foresees a fixed commissioning date for the Lamu coal power plant. Further macroeconomic impacts of developing the Lamu coal plant would include the increase of Kenya's dependency on energy imports and a consequent worsening of the country's trade balance.

3. **Geothermal power is more flexible and therefore more appropriate for the Kenyan context, given the uncertainty in future electricity demand.**
There is great uncertainty in future peak and baseload electricity demands, which is reflected by the fact that the high growth scenario is about twice as high as the low growth scenario [32], both in the PGTMP and the 2017-2037 LCPDP. For this reason, it is important for the Kenyan energy sector to adopt a flexible resource plan that allows for the addition of new capacity in smaller increments. The planned expansion

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[32] The low growth scenario presents a growth trajectory where most of the government plans are not implemented as planned. It is assumed that in this scenario, economic development will continue at the existing rate, with no expected increase during the planning period. The high growth scenario is based on the development patterns largely driven by Vision 2030 growth projections and the implementation of flagship projects.

of geothermal power in Kenya provides much more flexibility to planners, as geothermal power generation is more decentralised and divided among multiple smaller power plants. The implementation of a project the size of the Lamu plant might put sector stability, affordability, and sustainability at risk—for example, in the case of late transmission line delivery, resulting in penalty payments, or major blackouts, affecting the security of supply.

4. Using geothermal instead of coal to generate electricity leads to more domestic job creation.
The analysis conducted in this report shows that the scenario that relies more on geothermal power and does not include any coal-based power leads to more domestic job creation, both in the period of 2017-2037 and per year. Furthermore, a comparison of the performance of both generation technologies within one scenario (Reference Case) reveals that geothermal power triggers more short-term and long-term employment per MW than coal power. This can be explained by the fact that in the geothermal industry, expertise is locally available and sourced, whereas there is no experience in Kenya with coal-based power. If the Lamu coal power plant is built, the extent to which Kenyans will benefit is very limited, since a very large share (up to 50%) of the labour force will be foreigners mainly from China.

5. Negative effects on human health can be avoided if no coal-fired power plant is built.
Research shows that a significant benefit of geothermal power is its extremely low air pollutant emission rates, as geothermal power plants emit only a very small fraction (less than 1%) of the air pollutants emitted by coal-fired power plants of equal capacity. The quantitative analysis of the health impacts conducted in this report shows that up to 2065, roughly 1,620 Kenyans would die prematurely if both coal plants in Lamu and Kitui were built and operated and about 270 if only the Lamu plant was built and its capacity reduced to 450 MW, compared to 981 MW in the other scenario. The full extent of the health impacts of the coal-fired power plants, however, is likely to be significantly greater, since a whole range of indicators – including all morbidity-related factors, health impacts from other air pollutants and beyond the Kenyan border, effects on children, and work-days lost – were not included in the analysis.

6. Building the Lamu coal-fired power plant puts Kenya's climate change target at risk and may result in increased public spending in the event of a carbon price.
Kenya has committed to reducing annual GHG emissions by 30% below BAU by 2030, as announced in the country's NDC to the Paris Agreement. The development of the Lamu coal power plant puts achievement of this target at risk and creates additional pressure for other sectors to perform even better. Only if the Lamu coal power plant operates at extremely low capacity factors will Kenya's emissions reduction target not be jeopardised. However, this may not be politically feasible, given the size of the project and the investment involved. Although baseline emissions from electricity generation currently account for less than 2% of total national emissions, projections show that these emissions will increase to approximately 25% of total national emissions in 2030, due to significant additions in coal and natural gas generation capacity.

Furthermore, emissions calculations for different generation expansion scenarios show that by 2037, almost 3 $MtCO_2$ could be saved annually if coal were replaced with low-carbon alternatives such as geothermal energy, complemented by generic backup units. In the event of a carbon pricing policy, this could translate to cost savings of USD 160 million per year by 2037 if a low carbon price were applied, and USD 320 million per year if a high carbon price were applied.

Building and operating coal power plants in Kenya, starting with the Lamu coal power plant, would considerably slow down the development of readily available, clean, and increasingly low-cost geothermal and other renewable energy sources such as wind and solar and would impede the realisation of the aforementioned benefits to their fullest extent.

The following aspects should be considered for the future orientation of the geothermal sector, in order to ensure the best possible use of this resource:

7. Switching to binary geothermal plants in the future.

Where possible, it is recommended to switch to binary steam cycle technology, instead of flash power plants. While single flash technologies are better suited to providing baseload power, binary systems can operate flexibly and take better advantage of lower energy reservoirs. Operating a binary geothermal plant in a flexible mode does not increase the plant's O&M cost, as there is no cost for the unused geothermal fluid of a binary plant. The option to combine baseload and flexible modes makes binary systems an ideal candidate to fill several roles in the electricity sector, such as baseload, regulation, load-following, and reserve functions. In addition, binary systems have very low air pollutant emission rates. While flash and dry steam plants emit about 5% of the carbon dioxide, 1% of the sulphur dioxide, and less than 1% of the nitrogen and nitrous oxide emitted by a coal power plant of equal capacity, a binary geothermal plant produces near-zero emissions. Considering the power system needs, as well as environmental concerns, it is recommended that binary technology is used where feasible for future geothermal expansion in Kenya.

8. Adjusting PPAs to incentivise flexible use of geothermal power.

Geothermal plants have demonstrated that they can ramp up or down quickly, allowing them to adjust to the changing needs of the power system and act as a flexible power source, in addition to providing baseload supply. Considering the uptake of variable renewable energies in Kenya, the electricity sector requires technologies that can respond to changes in generation, in order to ensure that electricity supply and demand are always balanced. While it is physically possible for a geothermal power plant to provide a range of ancillary services for short- and long-term flexibility, such as spinning, non-spinning, and supplemental reserves, this is not economical under traditional PPA contract terms. With well-structured and appropriately priced contracts, however, geothermal plants can provide flexible power production in a cost-effective way. In order for this to happen, the terms would have to be modified to compensate geothermal power plants not only for providing baseload capacity, but also reserve capacity.

9. Ensuring site diversification

Currently, geothermal power is being harnessed in the Olkaria, Menengai, and Eburru fields. It is estimated that by 2035, half of the geothermal capacity will still be located in the Olkaria fields. The current and expected future dominance of geothermal capacity in Olkaria should be closely monitored in terms of security of supply—e.g. with regard to the geothermal source productivity, which could decrease—, along with the difficulties associated with evacuating power due to the remotely located sites of the power plants. To mitigate this risk, the development of new geothermal plants in other geothermal fields, such as Suswa, Longonot, Akiira, and Baringo Silali should be encouraged, once these sites have been sufficiently analysed.

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7 Annex

Figure 10: Overview of the scenarios used as inputs for the AIRPOLIM-ES

Scenario	Power plant	Start of operations	Lifetime (years)	Capacity (MW)	Capacity factor (%)	Heat rate (Btu/KWh)	Emissions control type	Plant efficiency
2017-2037 LCPDP reference scenario high coal	Lamu Power Station	2024	30	981	85%	8,836	Average	41%
	Kitui Power Station Unit 1	2034	30	320	85%	9,665	Average	37%
	Kitui Power Station Unit 2	2035	30	320	85%	9,665	Average	37%
	Kitui Power Station Unit 3	2036	30	320	85%	9,665	Average	37%
EPRA alternative scenario	Lamu Power Station	2034	30	450	85%	8,836	Average	41%

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