Implications of renewable resource dynamics for energy system planning: The case of geothermal and hydropower in Kenya

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ABSTRACT:

In 2016, almost 80% of Kenya's current electricity production came from renewables, mainly relying on hydro and geothermal resources. Both of those resources are subject to dynamics that affect utilization. In the case of geothermal resources excessive utilization can lead to production capacity losses. In the case of hydro resources climate change can reduce their availability. This paper investigates what the implications of the dynamics of those two renewable resources are for short- and long-term (sustainable) electricity system planning in Kenya. A demand driven bottom-up model representing the most prevalent technologies of Kenya's future electricity system, including geothermal and hydro dynamics, is used to run a total of eight different scenarios, varying in electricity demand and which resource dynamics are considered. Results show that in the long-term more installed capacity is necessary when geothermal and hydro resource dynamics are considered because of losses in production capacity. However, additional installed capacity does not translate into more production but leads to higher cost. The current power plan for Kenya and other electricity models do not address this issue. Unsustainable use of geothermal resources, if not addressed can lead to temporary depletion of the geothermal reservoirs with significant economic and sustainability related consequences.

Keywords: renewable resource dynamics; electricity system planning; Kenya; sustainable planning; System Dynamics

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Nomenclature

c	construction time [year]
ε	capacity factor [share]
A	power plant specific capital cost [$]
B	well capital cost [$/well]
c	construction time [year]
D	actual fuel cost [$/MWh]
E	well operation and maintenance cost [$/MWh]
F	levelized cost of original wells [$/well]
G	expected LCOE [$/MWh]
h	operating hours [h/year]
i	power plant
J	unit production cost [$/MWh]
K	lower limit of capacity factor [share]
l	lifetime [year]
r	discount rate [1/year]
S	expected average fuel cost [$/MWh]
t	time [year]
V	expected LCOE for geothermal [$/MWh]
w	well capacity [share]
Y	O&M cost [$/MWh]

1 Introduction

The aim of United Nations Agenda 2030 Sustainable Development Goal 7 (SDG7) is to "ensure access to affordable, reliable, sustainable, and modern energy for all" (United Nations, 2018). It acknowledges the importance of energy in shaping (sustainable) development as it is one of the key factors for achieving socio-economic development but also is one of the main drivers of climate change (Pachauri et al., 2012; Rao et al., 2014; Steffen et al., 2005; Steinberger and Roberts, 2010; United Nations, 2018). Hence, the challenge is to develop an energy system that supports socio-economic development and mitigates climate change. This is also the case for Kenya, since its government aims at transforming the country into a "newly-industrialising, middle income country providing a high quality of life to all its citizens in a clean and secure environment" as it is stated in Kenya Vision 2030 (Government of Kenya, 2018). While no specific goals for the energy system are defined, its development is a part of the foundation for being able to achieve the goals defined in the economic, political and social pillar of Kenya Vision 2030 (Gainer, 2015). The Kenyan government addresses energy related issues and defines related goals in the Least Cost Power Development Plan (e.g. (Lahmeyer International, 2016; Republic of Kenya, 2018)), which is published bi-annually.

In 2016, electricity accounted for 4% of total final energy consumption in Kenya. In 2015, 94% of urban population and 14% of rural population had access to electricity (Ogeya et al., 2018). The Kenyan government sees development of the electricity system as one of the key elements in Kenya's future development strategy. On the one hand, 100% electrification by 2030 is defined as one of the main goals in the Sustainable Energy for All – Kenya Action Agenda and is one of the key scenarios of future electricity expansion plans (Lahmeyer International, 2016; Republic of Kenya, 2018; SE4ALL, 2016). On the other hand, electricity expansion is prerequisite for a number of flagship projects in Kenya Vision, which are supposed to boost economic development (Government of the Republic of Kenya, 2007; Lahmeyer International, 2016; Republic of Kenya, 2018).

Kenya is endowed with significant renewable resources (Republic of Kenya, 2018). In 2016, almost 80% of the country's electricity production came from renewables, mainly hydro (34%) and geothermal (43%) resources (OECD/International Energy Agency, 2018). Although those renewable resources have several advantages over fossil fuels for electricity generation, they are subject to variations in resource availabilities, which can influence their sustainability in the long run. Yet, the impact of renewable resource dynamics on the electricity system is not fully represented in many existing power system planning models on regional and global level (de Boer and van Vuuren, 2017a; Mondal et al., 2017; Shafiei et al., 2016; Shmelev and Van Den Bergh, 2016). Energy and electricity system models applied to Kenya mainly dealt with assessing low carbon pathways and macro-economic effects of different scenarios (e.g. (Carvallo et al., 2017; Ogeya et al., 2018; Willenbockel et al., 2017)) or investigated what the optimal combination of on- and off-grid electrification was in Kenya (e.g.(Moksnes et al., 2017; Zeyringer et al., 2015)). While all of the studies follow the least cost optimization strategy, which is also endorsed by the Kenyan government, not all of them consider the effects on cost caused by specific characteristics of renewable resources. Some of the models are able to capture individual effects of the specificities of renewables, such as the variability of solar radiation, water or land constraints. However, geothermal resource dynamics are usually not considered explicitly in the models applied to the Kenyan case and only few consider the characteristics of hydro. Considering the current and anticipated large share of hydro and geothermal resources in total electricity generation in Kenya, it is important to capture the dynamics of those renewable resource and their impact on the sustainability of the electricity system, when planning for the future (Lahmeyer International, 2016). Hydro resources are highly climate dependent and geothermal resources can exhibit drawdown if utilized excessively for power production (Juliusson et al., 2011; Tarroja et al., 2016; Turner et al., 2017).

The focus of this paper are the effects of hydro climate change dynamics and geothermal resource utilization dynamics, which will be referred to as either resource dynamics, for both of them, or hydro/geothermal resource dynamics, when referring to them individually. The main research question of this paper is: What are the implications of hydro and geothermal resource dynamics for short- and long-term (sustainable) electricity system planning in Kenya? This question is answered by exploring the effects of hydro and geothermal resource dynamics on the government's plans of expanding Kenya's electricity system and the implications for sustainable development are discussed.

A demand driven least cost optimization bottom-up model representing the most prevalent technologies of the Long-term Least Cost Power Development Plan 2017 (see (Republic of Kenya, 2018)) for the Kenyan power sector is developed. To evaluate the impact of resource dynamics in different contexts, eight scenarios are run that differ in level of demand and to what extent resource dynamics are. The outcomes for energy system output variables are analysed and sustainability implications drawn.

The remaining part of this paper is structured into 5 sections. In Section 2, the background of renewable resource dynamics focusing on hydro and geothermal resources is presented. In Section 3 materials and methods of the study are provided. This includes a presentation of the electricity system model used to assess the implications of renewable resource dynamics in Kenya, data assumptions and scenario descriptions. In Section 4 the results of the modelling process are presented. In Section 5 the implications of the findings for sustainable development in the short- and long-term are discussed. Finally, Section 6 provides some concluding remarks.

2 Renewable energy resource dynamics

Renewable energy has been defined as: "a flow of energy, that is not exhausted by being used" (Serensen, 1991), including traditional energy sources and new renewables such as modern biofuels, wind, solar, small-scale hydropower, marine, and geothermal energy (UNDP, 2000). Renewable energy as defined in the IPCC report of 2011 includes "any form of energy from solar, geophysical or biological sources that is replenished by natural processes at a rate that equals or exceeds its rate of use. Renewable energy is obtained from the continuing or repetitive flows of energy occurring in the natural environment and includes low-carbon technologies such as solar energy, hydropower, wind, tide and waves and ocean thermal energy, as well as renewable fuels such as biomass" (IPCC, 2011). The German Advisory Council on Global Change (2003) states that renewables' "overall potential is in principle unlimited or renewable, and is CO_2-free or -neutral" (German Advisory Council on Global Change, 2003). Together those definitions address general aspects of renewable resources and their characteristics, but at the same time mask the diverse nature of renewable energy resources. For example, not all renewable resources are CO_2-free or –neutral, they are not all inexhaustible and the rate of use can be higher than the natural replenishment. These simplifications also appear in energy modelling where the diverse nature of renewable resources tends to be overly simplified.

In a study for the assessment of global energy resource economic potentials (Mercure and Salas, 2012), energy resources are defined as either "stocks, where energy may be extracted from fixed amounts of geologically occurring materials with specific calorific contents" or "renewable flows, where energy may be extracted from continuously producing onshore or offshore surface areas with wind, solar irradiation, plant growth, river flows, waves, tides or various forms of heat flows" (Mercure and Salas, 2012). According to this definition fossil fuels and nuclear would be characterized as stocks (accumulated over time) and all renewable resources would count as flows (available intermittently), implying continuous flows of energy. Such characterization may be misleading as some renewables can be almost depleted for a period of time, if the stock they are derived from are harvested excessively, and their regeneration rate is slower than their harvesting rate (Juliusson et al., 2011). Thus, it is argued that not all renewable energy sources can be seen solely as flows (flow-based), but rather as a combination of stocks and flows. Stock-based renewable resources can build up and accumulate in a stock (e.g. biomass, geothermal). Once sufficient stock is available, the resource can in principle be used at any time. Flow-based renewable resources are more or less temporarily available in unlimited quantities and energy can be harvested while the flow occurs, but they do not build up and accumulate (IPCC, 2011). Therefore, they cannot be stored without external storage and harvested at a later point in time. At the same time, making use of those flow-based renewable resources does not reduce their availability.

Another important aspect addressed in the literature is renewables' weather and climate dependency. The impact of climate change on renewable resources has increasingly gained attention (de Queiroz et al., 2016; Fant et al., 2016; Hisdal et al., 2007; Pryor and Barthelmie, 2010). The effects of climate change can be beneficial or disadvantageous depending on whether change in the climate increases or decreases the availability of a certain renewable resource (e.g. increased runoff for hydropower) or its production capacity (e.g. improved growth conditions for biomass) (Hisdal et al., 2007; Schaeffer et al., 2012; Shafiei et al., 2015a; Turner et al., 2017).

Each of the renewable energy resources has specific physical characteristics, including resource potentials and intermittency. So far, many modelers have either dealt with this by defining limits for the resources' availability to assess consequences of those exogenously defined potentials (e.g. (Lan et al., 2016; Mondal et al., 2017; Ou et al., 2018; Shmelev and Van Den Bergh, 2016)) or by applying cost-supply curves that account for the cumulative use of resources (e.g. (de Boer and van Vuuren, 2017b; Shafiei et al., 2017a, 2017b, 2015b, 2014)). Efforts to represent intermittencies of flow-based renewables in energy system models have been made, which should make it possible to create more realistic scenarios on the contribution of renewables to the overall energy system (e.g. (Després et al., 2017, 2015)). Accounting for feedback from using the resource to availability is however rarely done. If geothermal resources are available in the modelled region, their contribution in future energy system scenarios is usually examined in a simplified manner by including exogenous resource constraints or cost-supply curves (e.g. (Hori et al., 2016; Lenzen et al., 2016)), excluding feedbacks or non-linear behaviors. Linking geothermal resource dynamics to resource utilization for electricity production and the implications for unit production cost and production capacity has mainly been dealt with from a technical reservoir management perspective (Axelsson, 2012; Axelsson and Stefansson, 2003; Juliusson et al., 2011; Sigurdsson et al., 1995). The geothermal stock-like characteristic, which leads to a non-linear behaviour, has not been integrated in real cases of power system planning models. Finding ways to represent the geothermal resource as a stock and thereby representing the arising patterns in a simplified manner that allows its integration into energy system models has been dealt with to a limited extent (Júlíusson and Axelsson, 2018). This paper builds on the geothermal utilization model developed in (Spittler et al., 2020).

Possible effect of climate change on renewable energy resources is another feature that commonly is excluded. Geothermal resources are climate independent, but for hydro resources, including the impact of climate change implies changing assumptions of future flow rates and capacities, which are based on forecasted impacts of climate change on resource potential (e.g.(Shafiei et al., 2015a; Tanner and Johnston, 2017a)).

In conclusion, considering the stock and flow dynamics of renewable resources in future energy system planning is important if in particular the electricity supply system is largely reliant on hydro and geothermal resources in addition to biomass.

3 Material and methods

In this section the basic structure and main assumptions of the developed model are presented. Additionally, scenario parameters are defined. The System-Dynamics approach is chosen as the modelling methodology because the resources modelled collectively create a complex system, and their dynamics are characterized by non-linear feedback relationships and delays (Ford, 2009; Sterman, 2000).

3.1 Model description and main assumptions

The system dynamics model for the Kenyan on-grid electricity system consists of a detailed bottom-up structure, which encompasses power plants and economic calculations for each of the electricity generating technologies. The technologies included are: Multi Speed Diesel (MSD), Gas Turbine (GT), Hydro, Geothermal, Combined Cycle Gas Turbine (CCGT), Nuclear, Coal, Large-scale Wind and Large-scale Solar PV. The resource dynamics module captures the behaviour of geothermal resources based on the concepts and approach introduced in (Spittler et al., 2020).

The model follows a demand-driven approach, which means that forecasted electricity demand always needs to be met at the lowest possible cost. Demand is an exogenously defined parameter, which differs in the various scenarios. Associated supply is calculated on a yearly basis. Demand is split between peak- and base-load. Technologies are also distinguished between peak and base-load ones. This means selected plant types fulfil peak demand (i.e. Multi Speed Diesel, Gas Turbine, and Hydro) and others fulfil the base-load demand (Geothermal, Hydro, Combined Cycle Gas Turbine, Nuclear, Coal, large scale Wind, large scale PV) as defined in (Lahmeyer International, 2016). Because of a limited contribution of biomass resources to electricity generation, they are not considered in this study (Lahmeyer International, 2016).

Fig. 1 displays the basic structure of the model. It consists of three main modules (Power plants, Economics and Resource dynamics), and a decision-making algorithm, which are explained in the following sections. The arrows in Fig. 1 show the flow of information between the different modules.

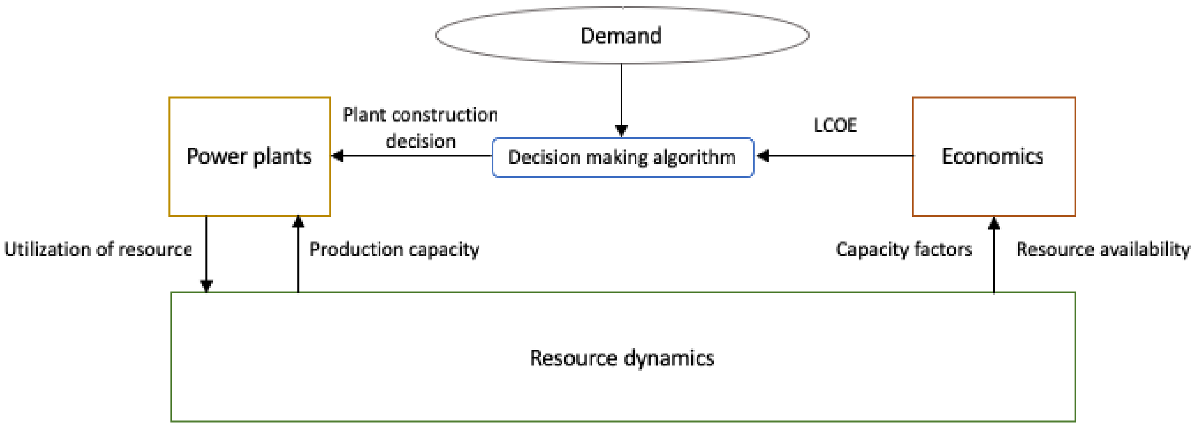

Figure 1: Kenya electricity model structure

3.1.1 Power plant and economics modules

The main decision variables, i.e. levelized cost of energy (expected LCOE) and available capacity are estimated in the power plant and economic modules. Their structure is based on the one presented in (Spittler et al., 2020). Cost calculations are the same for all power plants except for the geothermal plant. This is because plant and well costs are calculated separately and the resource dynamics influence cost calculation of the latter (Spittler et al., 2020).

The two main cost components in this module (i) expected LCOE and (ii) unit cost of electricity, are calculated for each plant individually. Based on expected LCOE, the model choses the cheapest technology to be built (see section 3.1.4 Decision making algorithm for plant construction). As displayed in Eq. 1, expected LCOE ($G_{i,t}$) is a function of the power plant specific capital cost ($A_{i,t}$), plant operation and maintenance cost ($Y_{i,t}$), expected average fuel cost ($S_{i,t}$) over the plant's lifetime (l), capacity factor ($\varepsilon_{i,t}$), discount rate (r), and hours of operation (h). Due to exogenous technological learning PV and wind power capital costs decrease over time, hence the expected LCOEs also decline. Storage technologies are not modelled as they are not considered in Kenya's Least Cost Power Development Plan (Lahmeyer International, 2016).

$$G_{i,t} = S_{i,t} + Y_{i,t} + A_{i,t} / \sum_{t=1}^{l} \frac{h_{i,t} \cdot \varepsilon_{i,t}}{(1+r)^t} \qquad (1)$$

In the case of hydro- and geothermal power the resource dynamics influence the expected LCOE of each plant (see section 3.1.2 for Geothermal dynamics and 3.1.3 for Hydro resource dynamics).

Unlike expected LCOE, the unit cost of electricity ($J_{i,t}$) reflects the actual cost at which electricity is produced once plant capacity has been installed. The general calculation for the unit cost of electricity is displayed in Eq. 2:

$$J_{i,t} = D_{i,t} + Y_{i,t} + A_{i,t} / \sum_{t=1}^{l} \frac{h_{i,t} \cdot \varepsilon_{i,t}}{(1+r)^t} \qquad (2)$$

For nuclear plants and power plants relying on fossil fuels, the unit cost of electricity differs from the expected LCOE because actual fuel prices ($D_{i,t}$) in a certain year (at time t) are used for its calculation (based on predicted fuel cost in (Lahmeyer International, 2016)) instead of expected average fuel cost over the power plant's life time. In the case of geothermal and hydropower plants, unit costs differ when resource dynamics are considered. This is because resource dynamics influence actual production (see section 3.1.2 and 3.1.3), due to changed capacity factors of hydropower and changed capacity factors of geothermal wells (Spittler et al., 2020). Detailed assumptions about the parameters for cost calculations for all technologies can be found in the Annex.

The structure of the power plant module is the same for all technologies but an additional module for wells is added in the case of geothermal power plants. Based on (Lahmeyer International, 2016), existing plants are represented by installed capacity and planned plants are counted as capacity under construction. Both capacity under construction and installed capacity are considered as available capacity for the future. Available capacity refers to remaining capacity that is still possible to be installed. For fossil fuel plants this capacity is in theory unlimited. For renewable resources (stock- and flow-based), this available capacity is constrained for each plant site (see Annex). The installed capacity times the capacity factor determines electricity production. The capacity factor is assumed to be constant for all technologies except for geothermal and hydro power. Once the economic lifetime of a certain plant has been reached, this capacity is retired or reinvested in, depending on relative costs.

3.1.2 Geothermal resource utilization dynamics

The causal loop diagram (CLD) presented in Fig. 2 depicts the main feedback loops related to geothermal resource utilization for electricity production. Arrows labelled with a "+" mean that cause and effect behave in the same direction (e.g. more original well construction leads to more wells) and arrows labelled with a "–" indicate that cause and effect move in opposite directions (e.g. the higher the well capacity the less original well construction). A detailed description of the geothermal resource dynamics are discussed in (Spittler et al., 2020). The colour of the lines was chosen to distinguish the loops. The dashed lines refer to connections not represented in some of the scenarios as discussed in section 3.2 Scenario description. The dotted blue lines that are not part of any causal loops in this structure represent important causal links of the resource dynamics to the cost of electricity production.

Geothermal resource dynamics are modelled for each individual geothermal power plant. Each geothermal field stock is reduced through electricity production and grows through natural recharge. Changes in this stock lead to changes in production capacity, which affects the level of well construction and unit production cost (Spittler et al., 2020). The five main balancing loops driving system behaviour are explained in more detail below:

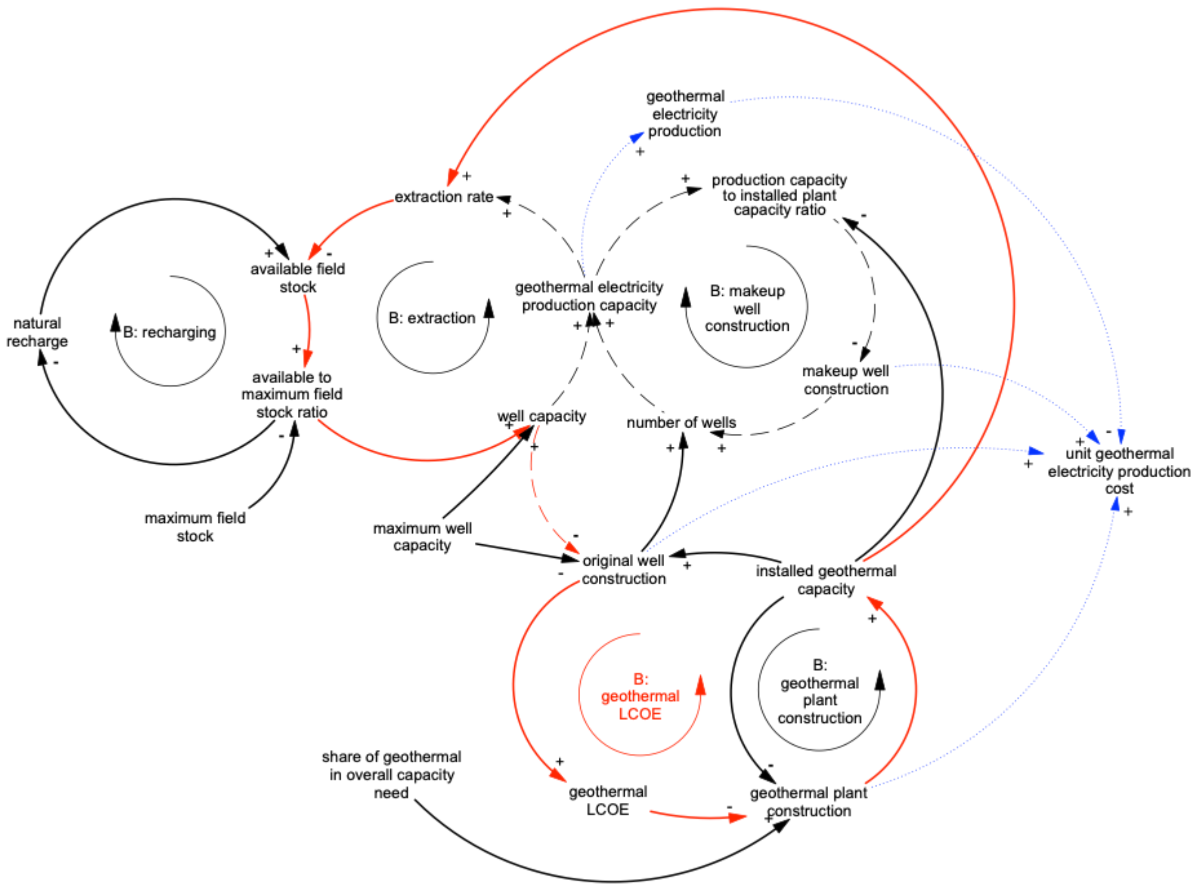

Figure 2: Main feedback loops of the geothermal resource dynamics for electricity production

- ***Geothermal plant construction***

New geothermal plant construction is driven by the share of geothermal capacity in overall capacity needed (see section 3.1.4) to meet the exogenously defined future electricity demand. The feedback from the economic part of the model to geothermal plant construction is represented through the geothermal expected LCOE loop as shown in Fig. 4. Installed plant capacity determines original well construction, which affects the number of wells and unit geothermal electricity production cost. (Spittler et al., 2020)

- ***Geothermal expected LCOE***

The geothermal expected LCOE loop (indicated in red colour in Fig. 4) displays the feedback between the economics of geothermal capacity build-up and the geothermal resource dynamics (Spittler et al., 2020). Increased new geothermal plant construction translates into more installed plant capacity. This leads to an increased extraction rate, which negatively impacts the field stock. A reduction in the field stock ratio (i.e. available to maximum field stock) leads to a lower well capacity ($w_{i,t}$), which means more original wells need to be constructed if at a later point in time additional new geothermal capacity is added to the field.

(Spittler et al., 2020) Hence, for additional installed geothermal capacity expected LCOE in that field are higher because total expected LCOE of geothermal electricity produced is the sum of expected LCOE of power plants ($G_{i,t}$) and levelized cost of original wells ($F_{i,t}$). A higher geothermal expected LCOE negatively influences new plant construction. In an undeveloped field, the maximum field capacity determines original well capacity. Only in an already developed field, well capacity influences original well construction. Besides the explained dynamics influencing overall geothermal expected LCOE, also power plant specific capital cost ($A_{i,t}$), plant operation and maintenance cost ($Y_{i,t}$), well operation and maintenance cost ($E_{i,t}$), well capital cost ($B_{i,t}$), well capacity ($w_{i,t}$), capacity factor ($\varepsilon_{i,t}$), discount rate (r), its lifetime (l), the hours of operation (h), and construction time (c) need to be considered. Eq. 3-5 display the calculations of geothermal expected LCOE as also presented in (Spittler et al., 2020):

$$G_{i,t} = Y_{i,t} + A_{i,t} / \sum_{t=1}^{l} \frac{h_{i,t} \cdot \varepsilon_{i,t}}{(1+r)^t} \tag{3}$$

$$F_{i,t} = E_{i,t} + B_{i,t} / \sum_{t=1}^{l} \frac{w_{i,t} \cdot h_{i,t} \cdot \varepsilon_{i,t}}{(1+r)^t} \tag{4}$$

$$V_{i,t} = G_{i,t} + F_{i,t} \tag{5}$$

Actual unit production cost differs from LCOE as geothermal drawdown causes additional well construction and reduces production capacity. A more detailed explanation can be found in (Spittler et al., 2020).

- ***Make-up well construction***

Make-up wells are those wells that get drilled in an already developed field in order to maintain production levels when production capacity decreases due to drawdown in the field. More make-up well construction leads to an increased number of wells, which again leads to larger electricity production capacity and geothermal expected LCOE. The higher the electricity production capacity, the higher will be the production to installed capacity ratio, and the less make-up well construction will be necessary. (Spittler et al., 2020) This loop is linked to the balancing loops of plant construction and extraction. The link to the geothermal plant construction loop is through the production to installed capacity ratio; the higher the installed capacity, the lower is the ratio. The link to the extraction loop is through electricity production.

- ***Extraction***

Extraction is driven by installed capacity and well production capacity. The higher the well production capacity and the installed capacity, the higher the extraction rate (i.e. electricity produced by a specific field), and the lower the available stock. The "available to maximum stock ratio" behaves in a way that the smaller that ratio, the lower is well capacity. Lower well capacity leads to less geothermal electricity production capacity, which ends in a decreased extraction rate. This balancing loop is connected to the recharging loop through the available stock and "available to maximum stock ratio" variables. (Spittler et al., 2020)

- ***Recharging***

This loop describes the balancing effect of natural recharge on the available stock, which is linked to "available to maximum stock ratio". Additionally, this ratio is determined by the exogenous parameter of maximum field stock (also see (Spittler et al., 2020))

Albeit not explicitly shown in the CLD, in combination, some loops together create a reinforcing behaviour such as the link between plant construction, make-up well construction and extraction. A possible outcome of these dynamics is that through the installation of new geothermal plant capacity and related original well construction, more extraction can occur. It, in turn reduces the field stock, which reduces well capacity and therefore limits the geothermal production capacity. However, caused by the link to make-up well construction, higher installed plant capacity (i.e. production capacity to installed plant capacity ratio) leads to additional well construction and a higher number of wells. This again allows for increased geothermal electricity production and extraction. The dynamics of these loops are ultimately linked to the unit cost of geothermal electricity production. The unit cost is lower if geothermal electricity production is higher, but it increases through well (original and make up) and plant construction.

3.1.3 Hydro climate change dynamics

The sustainability of hydropower has been assessed by several studies. For example, (Moran et al., 2018) assessed the environmental and social effects of hydropower developments in the 21st century and (Turner et al., 2017) investigated the consequences of climate change on hydropower globally. However, when modelling the future energy system for Kenya, the impacts of climate change on hydropower has only been addressed to a limited extent by (Lahmeyer International, 2016). Building on this Fig. 3 shows the two main loops that describe the utilization of hydropower for electricity generation and the role of climate change in it.

Like for Fig. 2 the dashed lines refer to connections not represented in some of the scenarios as discussed in section 3.2 Scenario description and the dotted blue lines display relevant causal links of the dynamics to the cost of electricity production. The dynamics of resources are presented and modelled for each hydropower plant. A distinction is made for hydro resources that are utilized for peak (P Hydro) and those that are utilized for large base (B Hydro) load demand in the model. Hydropower that is utilized for peak demand has smaller capacity factors than base load hydropower. In general, two balancing loops are responsible for the dynamics (Ebinger and Vergara, 2011):

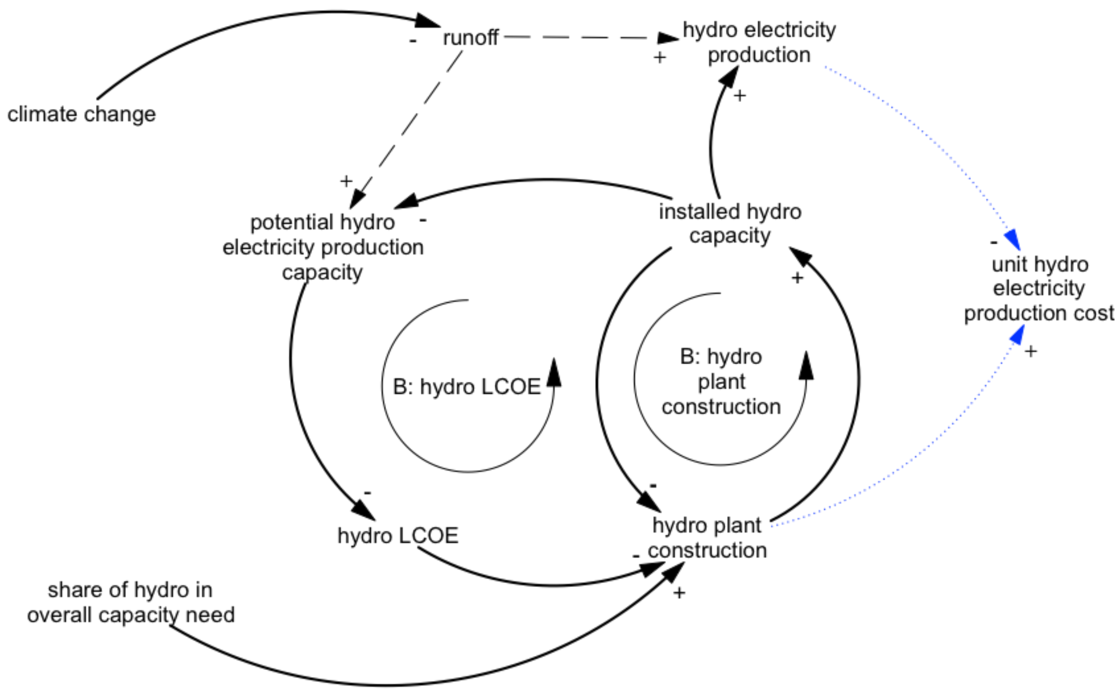

Figure 3: Main feedback loops of the hydro resource dynamics for electricity utilization

- ***Hydro plant construction***

The hydro plant construction loop follows the same logic as the geothermal plant construction loop. The more hydro plant capacity is installed, the less new hydropower plant construction is taking place. The balancing behaviour of this loop is created by the negative connection between installed hydro plant capacity and new hydro plant construction. However, new hydro plant construction is driven by the determined share of hydro capacity in the overall capacity needed to meet the exogenously defined future electricity demand. The feedback from the economic part of the model to hydro plant construction is represented through the hydro expected LCOE loop, which differs from the geothermal loop as the resource dynamics are different. (Ebinger and Vergara, 2011)

- ***Hydro expected LCOE***

The hydro expected LCOE displays the feedback between the economics of hydroelectric capacity build up and the hydro resource capacity. Increased hydro plant construction translates into more installed plant capacity. More installed plant capacity means more potential hydro electricity production, which due to economics of scale reduces expected LCOE of hydro plants and leads to additional hydro plant construction. The potential hydro electricity production capacity is positively related to available runoff, which is negatively influenced by climate change. The calculation of expected LCOE for hydropower is shown in Eq. 1. The capacity factor is assumed to exponentially decline towards its lower limit as defined in (Lahmeyer International, 2016). Due to changing capacity factors an estimate of the average capacity factor over the power plants lifetimes is made when the expected LCOE is calculated. Due to the changing capacity factors unit production cost at a certain point in time differs from expected LCOE.

In this case, climate change is an external driver, which influences the already existing dynamics of hydropower utilization. Historic data has shown that a negative polarity between "climate change" and "runoff" in Kenya exists. This has led to decreasing hydropower potentials (Lahmeyer International, 2016). Hence, climate change leads to higher unit cost for hydro electricity production. This is because a lower capacity factor leads to lower production while total cost stays constant. The calculation for unit production cost depends on the capacity factor of the respective year.

3.1.4 Decision making algorithm for plant construction

A central element of the model is the underlying decision-making structure for additional plant capacity. This decision is made separately for both load types (i.e. peak and base load). Fig. 4 shows the decision-making to determine what size and type of new capacity gets built and in what order. This algorithm is based on a cost minimization approach as presented in (Lahmeyer International, 2016).

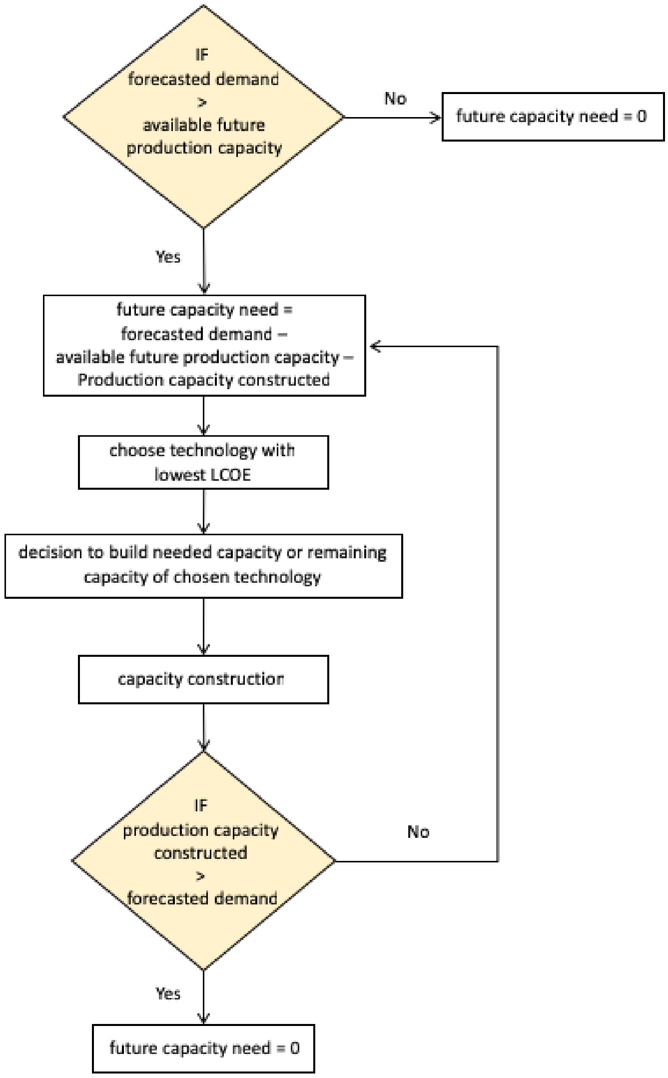

Figure 4: Capacity construction decision-making algorithm

If the forecasted demand is higher than the available future production capacity a future capacity need is identified. Once, this future capacity need is determined the cheapest expected LCOE and the corresponding technology and in the case of geothermal and hydro the corresponding plant is selected. Since capacity construction for plants cannot exceed available capacity, the model has to decide whether it is limited by remaining capacity or if forecasted demand can be fulfilled by the chosen technology or plant. When the decision on capacity construction has been made the model checks if the currently determined production capacity constructed can meet the forecasted demand. If this is not the case, the selection process for additional capacity starts again. The focus lies on production capacity rather than installed capacity because in case of geothermal and hydro, installed capacity can differ from actual production capacity as described in sections 3.1.2 and 3.1.3.

3.2 Scenario description

Eight scenarios are run from 2015 to 2050 and are defined based on the level of demand growth and whether the hydro and/or geothermal resource dynamics are considered or not. Both demand scenarios start from 9453 GWh for baseload and 1570 GWh for peak load (Lahmeyer International, 2016). The parameters are defined as the following:

- *Low demand:* Peak and base demand are assumed to grow at a yearly rate of 5.7% and 5.6% respectively. This means no flagship projects of Kenya Vision 2030 are implemented and translates into around 70% electricity access (Lahmeyer International, 2016).
- *High demand:* This means a yearly growth rate of 9.6% for base load and 9.8% for peak load. This demand is in accordance with Kenya Vision 2030 and the goal of 100% electricity access (Lahmeyer International, 2016).
- *Geothermal resource dynamics:* When geothermal resource dynamics are considered, the effects of geothermal resource utilization on the resource are considered. Hence, it incorporates the impact of resource utilization (i.e. electricity production) on resource patterns (i.e. changes in field stock and well capacity). Additionally, it accounts for the feedback from the geothermal resource to the cost and construction of geothermal power plants. This translates into make-up well construction and leads to changes in cost due to changes in well capacity. All causal connections (dashed and solid) as portrayed in Fig. 2 are considered.
- *Hydro resource dynamics:* The consideration of hydro resource dynamics means that the effect of climate change on the hydro resource is considered, which translates into lower capacity factors and therefore, higher production cost. In this scenario all causal links (dashed and solid) displayed in Fig. 3 are accounted for.
- *No geothermal resource dynamics:* When geothermal resource dynamics are not considered, it means that only utilization (i.e. electricity production) affects field stock and well capacity, but this is not reflected in plant or cost calculation modules. As a result, well capacity is assumed to be constant (i.e. maximum well capacity) in the power plant and cost calculation modules. Hence, only causal connections with solid lines, as presented in Fig. 2 are considered.

- *No hydro resource dynamics:* When hydro resource dynamics are not accounted for, the potential influence of climate change on the resource is neglected and a stable capacity factor is assumed. Therefore, only solid lines in Fig. 3 are considered.

In combination this results in the following eight different scenarios (S1-S8) displayed in Table 1:

Table 1: Scenario definition

	Demand level	Geothermal resource dynamics	Hydro resource dynamics
S1	low	no	no
S2	low	yes	no
S3	low	no	yes
S4	low	yes	yes
S5	high	no	no
S6	high	yes	no
S7	high	no	yes
S8	high	yes	yes

Assumptions that are not scenario specific can be found in the Annex.

4 Results

In this section the results regarding power plant capacity, utilization, cost and environmental results from the model are presented. Table 2 displays the numerical results for the relevant parameters for the years 2020, 2030 and 2050.

Table 2: Short- and long-term results for main parameters

		Installed capacity [MW]	Production [GWh]	Average unit production cost [cent/kWh]	Emissions [tCO2]
2020	***S1***	3831	20356	11	1241229
	S2	3831	20204	11	1241229
	S3	3831	19442	11	1241229
	S4	3831	19290	11	1241229
	S5	3831	20356	11	1241229
	S6	3831	20204	11	1241229
	S7	3831	19442	11	1241229
	S8	3831	19290	11	1241229
2030	***S1***	7186	36383	16	3917150
	S2	7186	36140	17	3917150
	S3	8726	37192	18	4488582
	S4	8726	36948	19	4488582

	S5	10070	48245	16	4626678
	S6	10070	48001	17	4626678
	S7	10660	43925	18	4945727
	S8	10660	43681	18	4945727
2050	***S1***	22353	95253	22	7631457
	S2	22353	94237	22	7631457
	S3	22829	94097	24	7721934
	S4	22829	92956	24	7721934
	S5	51807	234759	24	14655307
	S6	51807	233346	24	14655307
	S7	53478	236137	26	15231501
	S8	53478	234791	26	15231501

Table 2 supports the graphical results (i.e. Fig. 7 to 11) described in the following sub-sections by showing the exact values.

4.1 Capacity installation and utilization

Fig. 5 displays total installed capacity by scenario and energy type. In all scenarios, the largest share of peak capacity is MSD, independent of the level of assumed demand growth. In 2050, for base load, the largest share of installed capacity is geothermal for low demand scenarios and nuclear for high demand scenarios. Coal and CCGT are less competitive especially in the long run as renewables are cheaper in the beginning and after a certain demand threshold is reached, nuclear power becomes the cheapest available option. Most capacity for each demand category is installed in the scenarios in which either only hydro or both hydro and geothermal resource dynamics are considered (i.e. S3, S4 and S7, S8). This is because additional capacity needs to be installed to be able to compensate the losses caused by the resource dynamics. In the scenarios in which hydro resource dynamics are not considered (i.e. S1, S2, S5, S6) hydropower contribution is largest for base as well as peak load, for the latter it especially reduces MSD installations. In the low as well as high demand scenarios, wind power installations are the highest when either hydro or both resource dynamics are considered. This is because cost of hydro and geothermal power increases when resource dynamics are included as well as additional installations of electricity production capacity, which are often fossil fuel based. This applies to scenarios S3, S4, S7 and S8. In scenarios of low demand, wind power can compensate for additional installation needs caused by resource dynamics but in scenarios S5 to S8, nuclear becomes the most cost-effective option to satisfy the high demand. Solar PV only accounts for a small share in all scenarios because of cost. This reflects the government’s plans for Kenya’s future electricity system, which does not consider PV as a major source of electricity (Republic of Kenya, 2018).

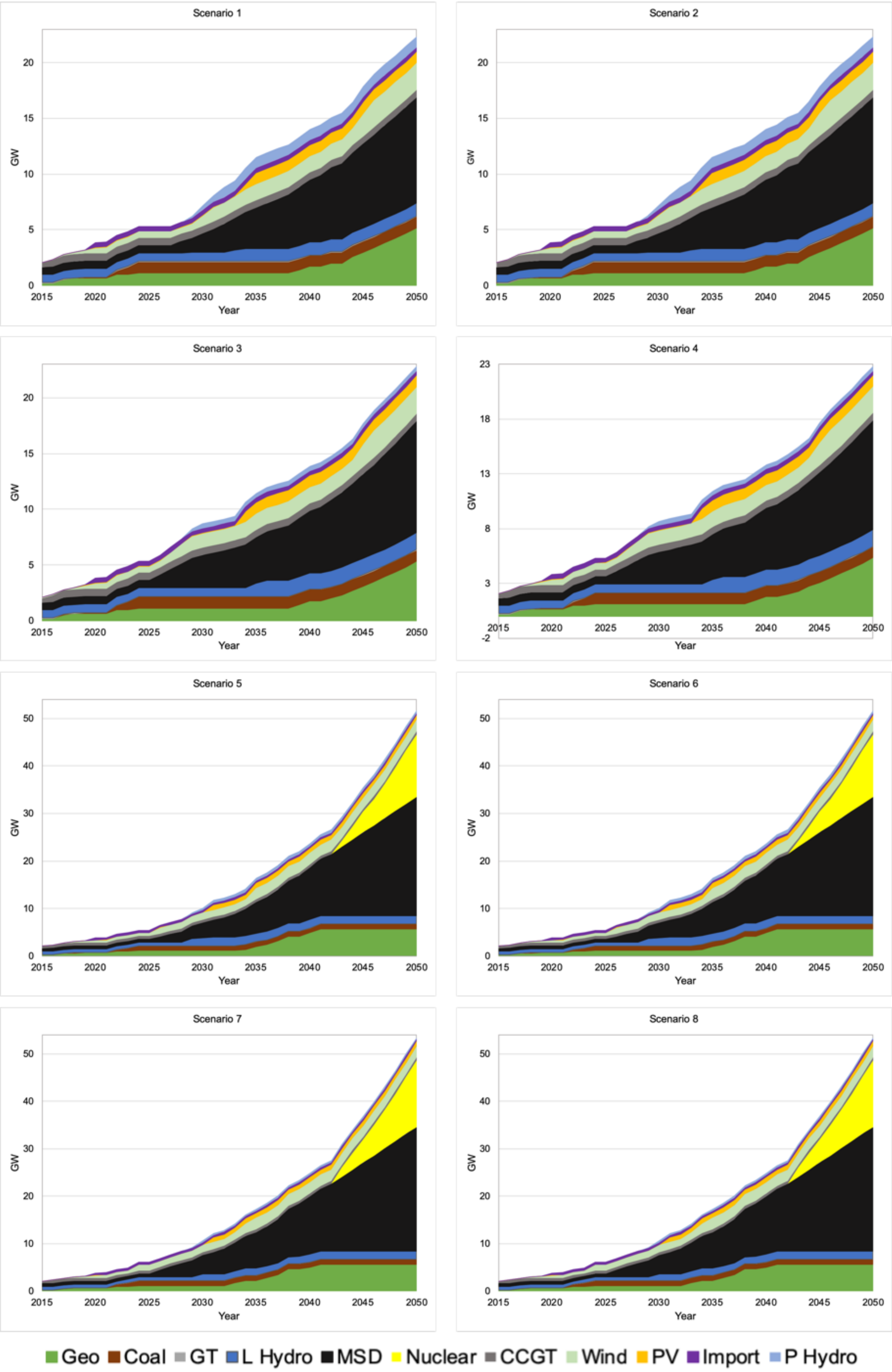

Figure 5: Installed capacity by source for each scenario

In Fig. 6 total production by source for each scenario is presented. It shows that the quantity of installed capacity in each scenario does not directly translate into actual production. This is because of the reduced production capacities when resource dynamics are accounted for. Scenarios with lowest installed capacity are not the ones in which least electricity is produced. In fact, overall installed capacity in low demand scenarios is smallest in S1 and S2. In high demand scenarios installed capacity is lowest in S5 and S6. In 2050, highest production levels in both demand categories occur in S1 and S5 (see Table 2). This is because resource dynamics are not included in S1 and S5, which means capacity factors for hydro and geothermal generation stay constant. Hence, installed capacity always translates into the same amount of production and no additional capacity is constructed to compensate production capacity losses. In S2 and S6 slightly higher installations levels are necessary to maintain production to fulfil demand. However, in both scenarios the production levels in 2050 are lower than when no geothermal or hydro resource dynamics are considered (see Table 2). This results from changes in capacity factors due to resource dynamics. For low demand levels least production occurs when both resource dynamics are considered. This is due to altered capacity factors and a delay in well construction and additional capacity construction. This is not the same for high demand levels. Nuclear power is built at such a large scale that it is able to compensate for this effect. Hence, least electricity is produced in S6. This is because geothermal resources are used excessively, which cause reduced geothermal production capacity. In combination with a delay in additional wells, to compensate production capacity losses, this leads to lower production levels. Overall, in 2050, in scenarios 1 to 4 (i.e. low demand scenarios) around 70% of electricity is produced from renewable resources. In scenarios 5 to 8 (i.e. high demand scenarios) only between 27 to 30% of electricity comes from renewable resources in 2050.

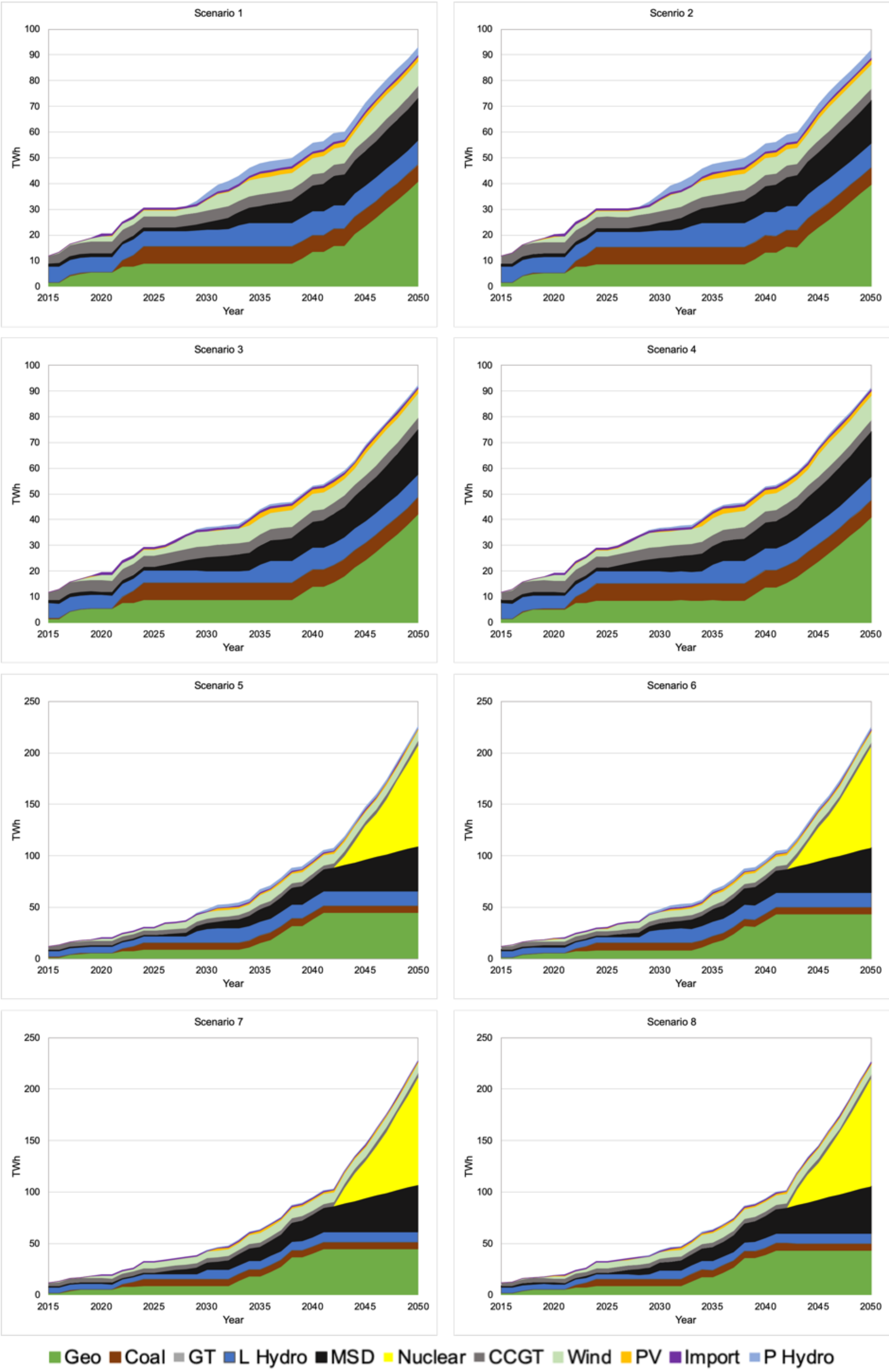

Figure 6: Production by source for each scenario

Capacity factors of hydropower plants gradually decline towards the lower value presented in Annex-Table 2. This means the production from the installed resources also declines over time. In the case of geothermal power, a constant capacity factor of 90% for all power plants is assumed. The actual capacity factors of each plant do not stay constant, because of geothermal drawdown make-up well construction, which only occurs with a delay, needs to compensate for potential capacity losses. Thereby, geothermal resource dynamics alter how much of the installed capacity can actually be utilized for electricity production. Fig. 7 presents the average actual capacity factor of all geothermal plants for scenarios that consider geothermal resource dynamics. High resource utilization due to high demand growth rates, decreases the average capacity factor in the long-term and significantly affects capacity factors and production of individual plants.

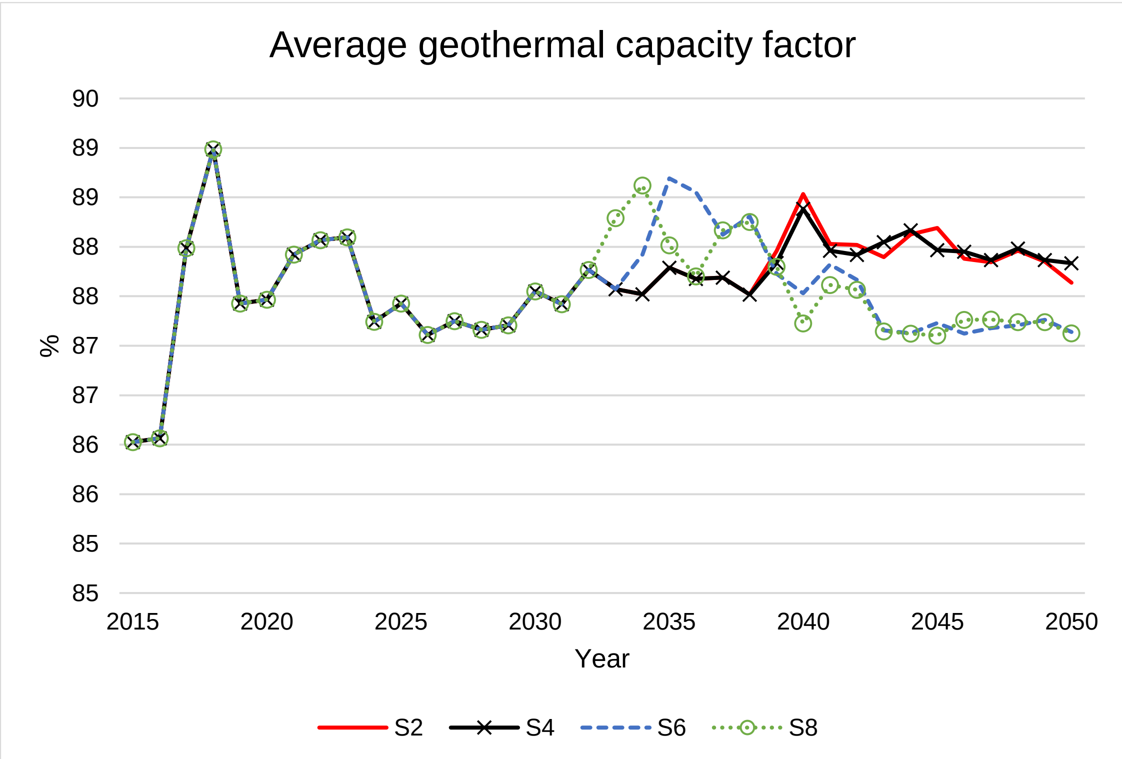

Figure 7: Average actual geothermal capacity factor for scenarios including geothermal resource dynamics (S2, S4, S6, S8) [%/year]

4.2 Cost

Fig. 9 depicts total cost differences between scenarios considering resource dynamics (S2-S4 and S6-S8) compared to those that do not consider them (S1 and S5). It shows total estimated electricity system development cost increases due to geothermal and hydro resource dynamics. When resource dynamics are considered, together or individually, total system cost of electricity supply is always higher than in scenarios in which no dynamics are considered. When only geothermal dynamics are considered (S2 and S6) the cost difference is gradually increasing but it never increases as much as in scenarios that also include hydro dynamics. This is because geothermal production capacity decreases appear gradually over a longer time period. Therefore, larger system impacts are realized slowly over time. Nonetheless, because of overuse of individual reservoirs unit production cost of individual plants can increase up to 76% in the short run, when geothermal resource dynamics are considered. This indicates an overutilization of a geothermal reservoir that is close to depletion. The longer geothermal resources get utilized excessively, the more investment is needed for makeup well construction. A significant share of geothermal capacity is only installed after 2035. In other scenarios, which also consider hydro resource dynamics, cost increases significantly. This is due to hydropower contribution to peak load and the constant reduction of hydro capacity factors. The effect on peak load is higher than on base load as capacity factors are already quite low and further reductions increase cost significantly. Hence, additional investment is needed to build additional capacity to maintain the required level of production. After some time, when hydro capacity factors have notably decreased and all economically viable hydro and geothermal resources have been exploited, investment shifts away from hydro and geothermal to other technologies. Therefore, the cost difference decreases again. In this case, peak load is covered by fossil fuel plants and base load by nuclear. The cost difference in low demand scenarios reaches a peak of 6.5 (S3) and 7.6% (S4) in the year 2032. In 2045, the cost difference is highest with 7 (S7) and 8.4% (S8). In general, hydro resource dynamics lead to larger differences, because of their contribution to peak load.

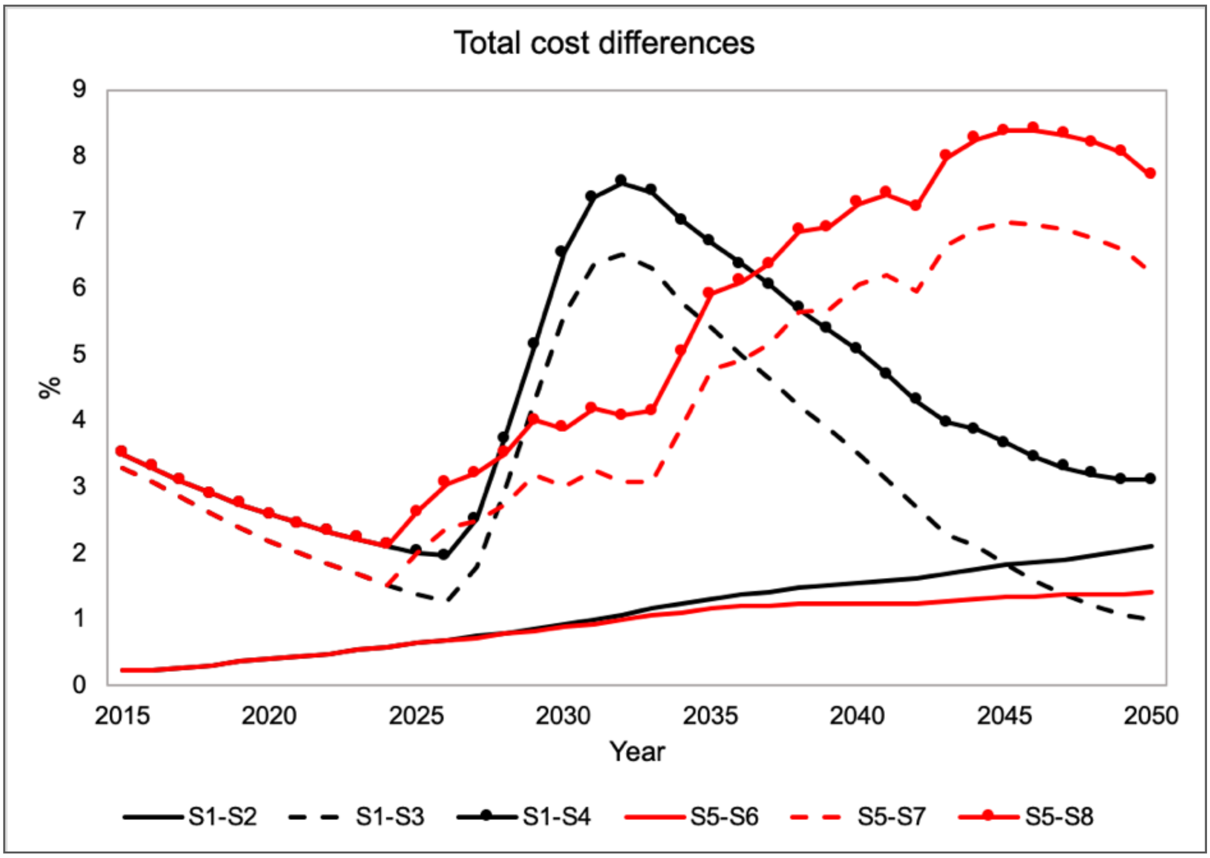

Figure 8: Differences of total cost between scenarios considering and scenarios not considering resource dynamics

Fig. 10 displays the average unit production cost in each of the scenarios. Overall, average unit production cost grows in all eight scenarios. The highest average unit production cost occurs in scenarios in which both resource dynamics are accounted for (S4 and S8). As for total cost differences, hydro dynamics have a larger impact on average unit production cost because they lead to significantly lower capacity factors for peak production of hydropower. Despite geothermal dynamics having a smaller impact on average unit production cost, the average unit production cost for geothermal electricity is around 15% (S2 and S4) and 22% higher (S6 and S8) in scenarios that consider geothermal dynamics. Generally, unit production cost in high demand scenarios (S4-S8) are higher than in low demand scenarios (S1-S4). This is because more capacity needs to be installed, which means once the cheapest technologies have been installed also more expensive ones get built.

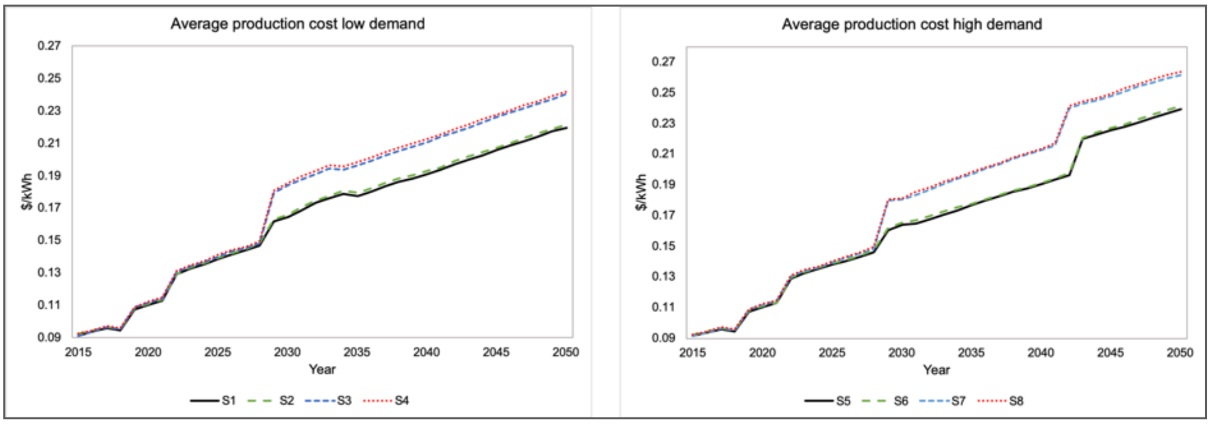

Figure 9: Average unit production cost by scenario

4.3 GHG emissions

Fig. 9 presents CO2 intensity of the electricity system by displaying emissions per GWh in each scenario. Generally, CO2 intensity is higher for scenarios, in which hydro resource dynamics are considered (S3, S4, S7, S8) than when only geothermal or no resource dynamics are considered. This is the case because of additional fossil power plant installations needed to compensate hydro capacity factor declines in peak demand. When geothermal resource dynamics are considered CO2 intensity is only affected minorly because it affects base load. Overall, CO2 emissions per GWh is decreasing because of increased built-up of low or zero CO2 technologies, such as wind, hydro, geothermal and nuclear, instead of coal and gas plants. Energy intensity falls faster in high demand scenarios because of the high share of nuclear in the electricity mix.

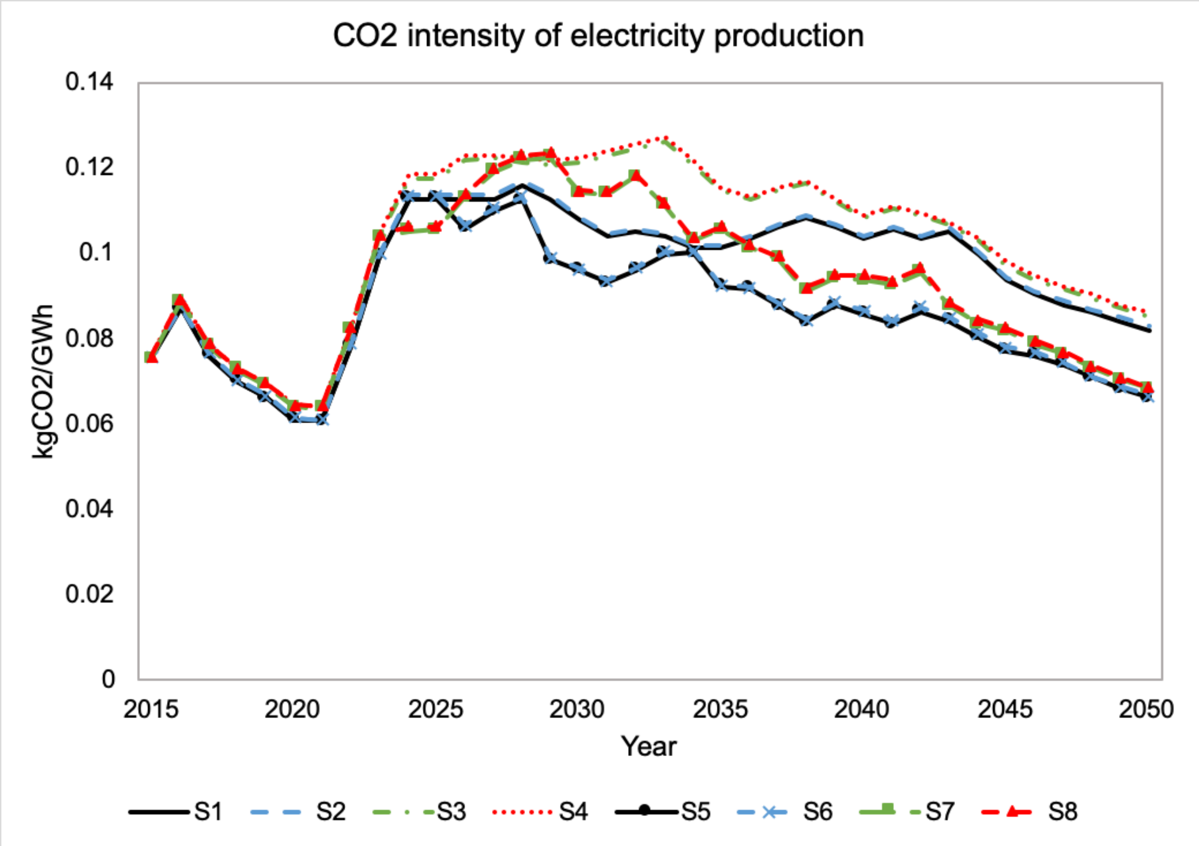

Figure 10: CO2 intensity of electricity mix [tCO2/GWh/year]

5 Conclusion and policy implications

Trade-offs between different (sustainable) electricity system development objectives can be observed between parameters and between their short- and long-term developments. As mentioned in the definition of the scenario parameters, a high electricity demand growth rate is needed to fulfil the goals of Kenya Vision 2030 (Lahmeyer International, 2016). At the same time, this high demand growth rate translates into lower production capacity of geothermal resources, higher cost and increased total emissions, although CO2 emissions per GWh are lower due to the large share of nuclear power in the electricity mix. Additionally, a long-term planning approach is needed to avoid negative effects within the energy sector in the future, such as resource exhaustion. According to Dalla Longa and Van der Zwaan, Kenya is able to achieve its climate change goals by 2030 through expansion of renewables (Dalla Longa and van der Zwaan, 2017). This is in line with the government's goal of supplying 80% of electricity from renewables by 2030. However, in the case of high demand scenarios, the share of renewables in the overall electricity supply significantly decreases by 2050 because overall more installations are needed than available economically feasible renewable capacity as outlined in the current plan of Kenya's government. However, Dalla Longa and Van der Zwaan (2017) state that an important prerequisite to achieving a high share of renewables in the energy mix is timely investment in low carbon technologies. This would mean that a re-evaluation and re-consideration of PV as well as concentrated solar (CS) in the on-grid electricity mix would be necessary to avoid high shares of fossil and nuclear production in high demand scenarios. Hence, policies that favour renewables and especially PV and CS technologies need to be put forward and need to be included when assessing least cost power development plans. In fact, Ondraczek (2014) found that the estimates of Kenya's government for LCOE of PV are too high. Also Rose et al. (2016) found that in combination with already existing hydro storage plants in Kenya, PV can be competitive with other technologies. They found that the government's plans of investment in wind, geothermal and hydropower reduces the value of PV (Rose et al., 2016). However, high electricity demand growth rates and geothermal and hydropower dynamics might alter those results in the long-term, as the effect is cumulative. With regards to nuclear, apart from the fact that a high share of nuclear would negatively affect the government's goals of a high share of renewables in the electricity mix, political and security risks exist. These are acknowledged in the Least Cost Power Development Plan and make actual implementation of such a project questionable, even if support among several stakeholders in Kenya's energy sector is present. While the above-mentioned trade-offs between short- and long-term developments of parameters exist independent of whether geothermal and hydro resource dynamics are considered or not, geothermal and hydro dynamics significantly affect the magnitude of development of parameters such as CO2 emissions and unit production as well as overall system cost. Suberu et al. argue that better planning in the energy sector is a necessary prerequisite to overcome the energy crisis prevailing in Sub-Saharan Africa (Suberu et al., 2013). This supports including geothermal and hydro resources more thoroughly in energy systems modelling and planning. So far, resource dynamics of geothermal resources have not been included into energy system planning and/or modelling in Kenya. An example for the importance of including resource dynamics is that average geothermal unit production cost in 2050 can be expected to be 20% higher than when its dynamics are neglected. In some scenarios individual plants have 76% higher unit production cost because of significantly lower actual capacity factors. Therefore, it is important to consider the resources' behaviour when for example, Power Purchase Agreements (PPAs) of geothermal plants are negotiated, to ensure continuous production by and profitability for the generators (Lahmeyer International, 2016).

Although this study deals with Kenya’s electricity system, the presented results link to several objectives of sustainable (energy) system development as defined by SDG 7 and the other 16 SDGs. The results highlight that trade-offs and synergies between some of them exist. On the one hand electricity system expansion is a prerequisite for achieving the goals of Kenya Vision 2030 and affects the SDG´s related to socio-economic development (e.g. SDG1, SDG3, SDG4, SDG8), on the other hand, sustainable development goals related to environmental and resources concerns (e.g. SDG13, SDG15) have to be considered. With regards to Kenya Vision 2030, the high electricity demand growth rate assumed in S5 to S8 is necessary for the implementation of defined flagship projects, which are seen as necessary to grow Kenya’s economy and well-being (Government of the Republic of Kenya, 2007; Republic of Kenya, 2018). In the current plan of Kenya’s government, the high electricity demand growth rate is also assumed to correspond with the goal of 100% electricity access by 2030 (i.e. SDG7) (SE4ALL, 2016). Electricity access was found to positively affect educational attainment and life expectancy (i.e. SDG3 and SDG4) (Collste et al., 2017). Apart from the beneficial effects of 100% electricity on population and wealth, it was also found to reduce deforestation in rural areas, which corresponds with targets of SDG15 (Tanner and Johnston, 2017b). However, in the scenarios of high demand (S5-S8) cost are higher than in low demand scenarios (S1-S4) and the resources’ dynamics even enhance cost. This negatively impacts the target of affordable energy for all within SDG7, as higher unit production cost translates into higher electricity prices. Higher demand leading to increased electricity production also means higher emissions, which negatively influences climate change and the achievement of SDG13. Resource dynamics cause even higher emissions as more fossil fuel resources need to be utilized for electricity production. Costs are lower in the low demand scenario, than in the case of high demand. Hence, while energy might be more affordable in that case, this type of demand growth is correlated to lower economic growth (Lahmeyer International, 2016). Thereby, the positive effect on related SDGs (SDG3, SDG4, SDG1) could be diminished.

The presented model follows a demand-driven approach, which does not account for market price (i.e. ignoring effects of price elasticities of production and demand) and the resulting effects on production and consumption (Shafiei et al., 2015b). Including feedback between production cost, supply and demand can allow for further insights into potential future paths of Kenya’s energy system and policy recommendations. However, it is beyond the scope of this research as it aims at exploring the significance of the effects of resource dynamics on the supply side for future planning rather than estimating likely energy system developments as a whole. In order to understand the contribution of PV and CS in peak and base-load demand a more detailed modelling approach of hourly load profiles, as for example presented in (Pietzcker et al., 2016), would need to be applied. Using system dynamics for capturing the dynamics of hydro and climate change as well as geothermal drawdown due to overutilization has proven valuable but limitations occur with regards to modelling detailed load profiles.

Although electricity only accounts for a small part of current energy demand in Kenya, the anticipated expansion of overall electricity generating capacity and especially geothermal and hydroelectricity make it important to consider the dynamics of these resources. The results in this paper confirm that the integration of renewable resource dynamics of hydro and geothermal for electricity generation affects overall electricity supply patterns as well as system costs. Geothermal resource dynamics lead to higher required capacity installations because of losses in production capacity and related significant drawdown of the resource, which is not captured by models currently used for electricity system planning in Kenya. Hence, additionally installed capacity does not translate into more production. This leads to increased estimated overall system cost, which can be up to 9% higher than when no resource dynamics are considered. Moreover, geothermal and especially hydropower are partly compensated by nuclear and fossil technologies, which affect GHG emissions. Renewable resource dynamics are especially relevant when planning for high demand growth, as is expected to occur in Kenya and when looking at short- and long-term developments of the electricity system as a whole. Certain parameters within it or implications for sustainable development, such as electricity cost and emissions increase. Additionally, the inclusion of resource dynamics can also help to understand the sustainability of the resource utilization itself. By integrating geothermal and hydro resource dynamics into the supply side structure of the electricity system, an important component that needs to be considered when planning Kenya’s future energy system has been added. Analysis without such representation can lead to inaccurate information on for example investments needs or CO2 emission and thereby, result in sub-optimal policies and energy system design.

ANNEX

Annex - Table 1: Data for expected LCOE and unit production cost calculations fossil fuel plants

<table>
<tr><th></th><th>Maximum plant size</th><th>Minimum plant size</th><th>CAPEX</th><th>Fixed O&M</th><th>Variable O&M</th><th>Fuel cost</th><th>Fuel cost increase</th><th>Construction time</th><th>Lifetime</th><th>Capacity factor</th></tr>
<tr><td></td><td>MW</td><td>MW</td><td>$/kW [1,2]</i></td><td><i>$/kW/year [1,2]</td><td>$/MWh [1,2]</i></td><td><i>$/kWh [3]</td><td>% [4]</td><td>years [1]</td><td>years [1]</td><td>% [1]</td></tr>
<tr><td>Coal Lamu</td><td>981</td><td rowspan="3">240</td><td>2479</td><td>80</td><td>1.3</td><td rowspan="3">0.03715</td><td rowspan="3">5.3</td><td rowspan="3">6</td><td rowspan="3">30</td><td rowspan="3">75</td></tr>
<tr><td>Coal Kitui</td><td>960</td><td rowspan="2">2388</td><td rowspan="2">69</td><td rowspan="2">1.4</td></tr>
<tr><td>Coal Generic</td><td>n.a.</td></tr>
<tr><td>GT Generic</td><td>n.a</td><td rowspan="2">27</td><td>857</td><td rowspan="2">20.9</td><td rowspan="2">12.5</td><td rowspan="2">0.1331</td><td rowspan="2">9.6</td><td rowspan="2">1</td><td rowspan="2">25</td><td rowspan="2">20</td></tr>
<tr><td>GT Nairobi</td><td>n.a.</td><td>1242</td></tr>
<tr><td>MSD Generic</td><td>n.a.</td><td>30</td><td>1618</td><td>31.5</td><td>8.8</td><td>0.0586</td><td>9.6</td><td>2</td><td>20</td><td>20</td></tr>
<tr><td>Nuclear Generic</td><td>n.a.</td><td>400</td><td>6858</td><td>7.5</td><td>10.2</td><td>0.0116</td><td>1</td><td>10</td><td>40</td><td>85</td></tr>
<tr><td>CCGT Generic</td><td>926</td><td>27</td><td>1174</td><td>31</td><td>13.2</td><td>0.03715</td><td></td><td>3</td><td>20</td><td>75</td></tr>
</table>

Annex - Table 2: Data for expected LCOE and unit production cost calculations hydro power plants

<table>
<tr><th></th><th>Maximum plant size</th><th>Minimum plant size</th><th>CAPEX</th><th>Fixed O&M</th><th>Variable O&M</th><th>Construction time</th><th>Lifetime</th><th>Capacity factor base load high</th><th>Capacity factor reduction base load</th><th>Capacity factor peak load high</th><th>Capacity factor reduction peak load</th></tr>
<tr><td></td><td>MW</td><td>MW</td><td>$/kW [1,2]</i></td><td><i>$/kW/year [1,2]</td><td>$/MWh [1,2]</td><td>years [1]</td><td>years [1]</td><td>% [5]</td><td>% [5]</td><td>% [5]</td><td>% [5]</td></tr>
<tr><td>SangOro</td><td>20</td><td rowspan="20">20</td><td>3430</td><td>27.4</td><td rowspan="20">0.5</td><td rowspan="20">7</td><td rowspan="20">40</td><td>95</td><td>70</td><td>66</td><td>17</td></tr>
<tr><td>SondoMiriu</td><td>60</td><td>3430</td><td>27.4</td><td>96</td><td>75</td><td>69</td><td>18</td></tr>
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<tr><td>Magwaga</td><td>119</td><td>4431</td><td>28</td><td>91</td><td>64</td><td>50</td><td>18</td></tr>
<tr><td>Arror</td><td>59</td><td>3087</td><td>20</td><td>91</td><td>64</td><td>50</td><td>18</td></tr>
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</table>

Annex - Table 3: Data for expected LCOE and unit production cost calculations wind power plants

	Maximum plant size	Minimum plant siize	CAPEX	Fixed O&M	Variable O&M	Construction time	Lifetime	Capacity factor
	MW [6]	*MW*	*$/kW*	*$/kW/year [1,2]*	*$/MWh [1,2]*	*years [1,2]*	*years [1,2]*	*% [6]*
Lake Turkana	1000	10	2030	76.1	0	2	20	55
Aeolus Kinangop	60		2000					34
Kipeto	100		2010					46
Prunus	51		2030					40
Meru	400		2000					32
Ngong	26		2030					35
OlDanyat	10		2030					40
Malindi	50		2030					40
Limuru	50		2030					40
Kajiado	50		2030					40
Marsabit	600		2030					40

Annex - Table 4: Data for expected LCOE and unit production cost calculations geothermal power plants

	Maximum field stock	Maximum well capacity	Maximum recharge	Recharge coefficient	Maximum plant size	Minimum plant size	CAPEX power plant	Fixed O&M total	Variable O&M total	CAPEX well	Construction time	Lifetime	Capacity factor
	TWh [8]	*MW [8]*	*MW [8]*	*1/TWh [8]*	*MW [7]*	*MW*	*$/kW [9]*	*$/kW/year [9]*	*$/kWh [9]*	*M$/well [9]*	*years [1]*	*years [1]*	*% [1]*
Olkaria 1	57.16	4	326	0.01	261		2054	136.9					
Olkaria 2	22.12	5.5	126	0.03	101		1801	137.6					
Olkaria 3	24.09	6	138	0.03	110		3022	87.6					
Olkaria 4&5	61.32	7	350	0.01	280		2054	136.9					
Olkaria 6	30.66	6.3	175	0.02	140		2054	136.9					
Olkaria 7	30.66	5	175	0.02	140		2054	136.9					
Olkaria 8	30.66	6.5	175	0.02	140		2054	136.9					
Olkaria 9	30.66	6.3	175	0.02	140		2054	136.9					
Olkaria Wellheads	19.71	6.7	113	0.04	90		673	111.62					
OrPower	0.00	0	0	0.00	0		0	0					
Eburru 2	5.48	5.9	94	0.13	75		2810	153.2					
Menengai 1	22.56	4.9	129	0.03	103	25	2082	136.4	0	6.55	9	25	90
Menengai 2	78.84	5.8	450	0.01	360		2040	135.4					
Menengai 3	21.90	4.3	125	0.03	100		2130	136.1					
Menengai 4	65.70	5	375	0.01	300		2130	136.1					
Menengai 5	131.40	6	750	0.01	600		2130	136.1					
Suswa 1	32.85	4.7	188	0.02	150		2130	136.1					
Suswa 2	131.40	4.3	750	0.01	600		2130	136.1					
Baringo Silali 1	109.50	5.5	625	0.01	500		2130	136.1					
Baringo Silali 2	241.00	4.9	1380	0.03	1100		2130	136.1					
Baringo Silali 3	30.66	5.1	175	0.02	140		2130	136.1					
Akiira	30.66	5.2	175	0.02	140		2290	137.5					
AGIL	30.66	4.8	175	0.02	140		2290	137.5					

Annex - Table 5: Other assumptions for cost calculations [10]

Discount rate	12%
Cost reduction PV	1.5%
Cost reduction wind	0.5%

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* [2] Lahmeyer International. Development of a Power Generation and Transmission Master Plan, Kenya. Nairobi, Kenya: Ministry of Energy and Petroleum; 2016. pp 178-181

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* [4] Republic of the Republic of Kenya. Updated Least Cost Power Development Plan (LCPDP) Study Period: 2017-2037. Nairobi, Kenya: Government of the Republic of Kenya; 2018. p 75

* [5] Lahmeyer International. Development of a Power Generation and Transmission Master Plan, Kenya. Nairobi, Kenya: Ministry of Energy and Petroleum; 2016. p 169

* [6] Lahmeyer International. Development of a Power Generation and Transmission Master Plan, Kenya. Nairobi, Kenya: Ministry of Energy and Petroleum; 2016. p 171

* [7] Lahmeyer International. Development of a Power Generation and Transmission Master Plan, Kenya. Nairobi, Kenya: Ministry of Energy and Petroleum; 2016. p 112-113

* [8] Based on Maximum plant size [7] and Lifetime [1]

* [9] Based on CAPEX and O&M values presented in [1] and [2]

* [10] Lahmeyer International. Development of a Power Generation and Transmission Master Plan, Kenya. Nairobi, Kenya: Ministry of Energy and Petroleum; 2016.

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