Prospects for Grid-Connected Solar PV in Kenya

by

Amy Michelle Rose

B.S. Space Physics
B.S. Aerospace Engineering
Embry-Riddle Aeronautical University, 2007

Submitted to the Engineering Systems Division
in partial fulfillment of the requirements for the degree of

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Abstract

Kenya’s electric power system is heavily reliant on hydropower, leaving it vulnerable during recurring droughts. Supply shortfalls are currently met through the use of expensive leased diesel generation. Therefore, plans for new generation focus on geothermal and conventional thermal sources. While these technologies offer a lower-cost alternative to leased diesel, they require large upfront capital investments in new infrastructure. I propose that grid-connected solar PV offers an alternative solution to displace expensive diesel generation, while capitalizing on Kenya’s abundant solar resource and avoiding large upfront financing requirements. Coordinated operation of Kenya’s extensive reservoir hydro capacity can overcome intermittency problems associated with solar generation and offer a low-cost path to grid-connected solar PV by eliminating the need for additional investment in storage.

This study uses a static expansion planning model of Kenya’s power system representing the years 2012 and 2017 to evaluate the feasibility of grid-connected solar PV under different price and hydrological conditions. These results reveal that high penetrations of solar PV can be integrated into the current system without increasing total system costs. By 2017 extensive planned investments in low-cost geothermal, imported hydro, and wind power will significantly reduce production from fuel oil plants and solar PV is no longer economically competitive at current prices.

The 2017 analysis does not evaluate scenarios where the price of solar PV decreases, new capacity is delayed, or PV capacity eliminates the need for new transmission infrastructure required for planned generation assets. Any of these scenarios increases the competitiveness of solar PV in the 2017 system. The methodology developed in this study could be used for system level evaluation of solar and other intermittent renewables in other hydro-dominated electric power systems in Africa.

Thesis Supervisor: Robert J. Stoner
Title: Associate Director, MIT Energy Initiative

Thesis Supervisor: Ignacio J. Pérez-Arriaga
Title: Visiting Professor, Engineering Systems Division
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<tr>
<td>a-Si</td>
<td>Amorphous Silicon</td>
</tr>
<tr>
<td>BAU</td>
<td>Business-as-usual</td>
</tr>
<tr>
<td>BOS</td>
<td>Balance of System</td>
</tr>
<tr>
<td>CdTe</td>
<td>Cadmium Telluride</td>
</tr>
<tr>
<td>CIGS</td>
<td>Copper Indium Gallium Selenide</td>
</tr>
<tr>
<td>c-Si</td>
<td>Crystalline Silicon</td>
</tr>
<tr>
<td>CSP</td>
<td>Concentrating Solar Power</td>
</tr>
<tr>
<td>DNI</td>
<td>Direct Normal Insolation</td>
</tr>
<tr>
<td>EPP</td>
<td>Emergency Power Producer</td>
</tr>
<tr>
<td>ERC</td>
<td>Energy Regulatory Commission</td>
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<tr>
<td>FIT</td>
<td>Feed-in-tariff</td>
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<tr>
<td>GDC</td>
<td>Geothermal Development Company</td>
</tr>
<tr>
<td>GHI</td>
<td>Global Horizontal Insolation</td>
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<tr>
<td>GoK</td>
<td>Government of Kenya</td>
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<tr>
<td>GW</td>
<td>Gigawatt</td>
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<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
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<tr>
<td>KenGen</td>
<td>Kenya Electricity Generating Company</td>
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<tr>
<td>KETRACO</td>
<td>Kenya Electricity Transmission Company</td>
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<tr>
<td>KPLC</td>
<td>Kenya Power and Lighting Company</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt-hour</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized Cost of Energy</td>
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<tr>
<td>LDC</td>
<td>Least Developed Countries</td>
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<tr>
<td>LNG</td>
<td>Liquified Natural Gas</td>
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<tr>
<td>MJ</td>
<td>Megajoule</td>
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<tr>
<td>MW</td>
<td>Megawatt</td>
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<tr>
<td>MSD</td>
<td>Medium-speed Diesel</td>
</tr>
<tr>
<td>Mth</td>
<td>Megatherm</td>
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<tr>
<td>OOC</td>
<td>Out of Commission</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
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<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>REA</td>
<td>Rural Electrification Authority</td>
</tr>
<tr>
<td>SWERA</td>
<td>Solar and Wind Energy Resource Assessment</td>
</tr>
<tr>
<td>Th</td>
<td>Thermie</td>
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<tr>
<td>VAT</td>
<td>Value Added Tax</td>
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Access to modern energy services for lighting and cooking has important links to economic development, poverty alleviation and improved health [33, 76, 78]. Despite these links, over 590 million people in sub-Saharan African remain without access to electricity [12]. In Kenya, the majority of the population is not connected to the electric grid and those who are connected face persistence outages due to shortfalls in supply as investments in new generation assets have failed to keep pace with demand growth. As a result, the Kenyan system operator has resorted to expensive alternatives to meet demand in the form of leased diesel generators. Spurred by rapid demand growth, averaging 7% annually, and national goals to increase electricity access rates to 40% by 2030, system planners are faced with the need to significantly increase generating capacity in the coming years [7, 53]. Kenya’s abundant solar resource and the potential to interoperate solar and hydro generation make solar PV a potential candidate to meet this challenge.

To test the hypothesis that solar photovoltaic (PV) generation can
be economically integrated into the Kenyan system through coordinated management with the existing reservoir hydropower plants, I have developed a computational model of the Kenyan power system. This model incorporates all major power stations in the country and evaluates total system costs and operating regimes under different scenarios of added solar PV capacity. The need for increased generation capacity, availability of reservoir hydro capacity, and abundant solar resources is not unique to Kenya. Therefore, I believe the methods developed in the course of this work can provide a framework for system level evaluation of solar and other forms of intermittent renewables in other hydro-dominated electric power systems in Africa.

1.1 Motivation for the Study

This study was motivated by five important aspects of the Kenyan power system. First, Kenya has an abundant solar resource — so far harnessed only for small-scale applications (i.e., solar home systems and lanterns). Second, a heavy reliance on reservoir hydropower resources leaves the country vulnerable to power shortages during the dry periods. Droughts, flooding, and seasonal variations in rainfall have increased in recent years as a result of climate change and the effects of widespread deforestation [68], aggravating this problem. Third, growing demand for electricity will require more generating capacity. The dwindling availability of untapped cheap hydropower resources and concerns about climate change effects on existing hydropower generators
have prompted the need for alternative generation technologies. Kenya has limited coal resources and no developed petroleum resources. By exploiting the available solar resource, Kenya can reduce crude oil imports and vulnerability to increases and volatility in imported fossil fuel prices. Fourth, hydropower can be used to facilitate the integration of intermittent renewable sources, such as solar and wind, by offsetting diurnal fluctuations in output. Fifth, solar PV plants can be strategically sited and sized to feed specified load centers, allowing increased generation capacity without extensive upgrades to the transmission infrastructure that may be needed for thermal plants.

While this study is focussed on the prospects for solar PV in the Kenyan system, the results may be applicable to other sub-Saharan African countries. The African continent has an abundant solar resource and planners in several countries including Ghana, South Africa, Rwanda, Egypt, and Morocco are contemplating extending their use of solar power beyond solar lanterns and solar home systems to utility-scale plants [51, 59, 57, 69]. The reliance on hydropower is also present in other African countries, with at least 40% of generation capacity coming from hydropower in 24 countries [7]. However, non-hydro generation in many of these regions is often dominated by expensive diesel generation. In many cases, including Kenya, all or part of this diesel capacity comes from leased plants that incur additional annual leasing costs. Assuming demand for electricity across the continent continues to grow at an average rate of 5% annually, and over 10% in some
countries [7], the demand for economic alternatives to increased diesel generation will increase. The approach developed in this study could potentially be applied by system planners in other hydro-rich African countries.

1.2 Research Questions

The goal of this study is to determine if solar PV can provide an economic solution to Kenya’s need for new generation assets and how institutional or operational reforms can encourage large-scale solar deployment. The following set of research questions address this goal:

1. Can solar PV be added to the existing system without increasing mean unit costs?

2. What tariff could be offered to solar generators without increasing system costs?

3. How would added solar capacity impact planned generation expansion in 2017?

4. How are these findings affected by uncertainties in:
   - price of petroleum
   - hydro inflows
   - demand growth

This study is meant to provide a top level assessment of the impacts of added solar PV to the Kenyan system. As such it does not address
network optimization or dynamic expansion planning for the generation or transmission systems.

1.3 Structure of Thesis

This thesis is divided into seven sections. In Chapter 2 I provide an overview of the Kenyan energy sector and discuss the solar resource in Kenya and solar technologies considered in the study in Chapter 3. An overview of previous work is provided in Chapter 4. Chapter 5 the model methodology and formulation is presented followed by the results in Chapter 6. Finally, Chapter 7 contains a summary of key findings, discussion of the policy and regulatory implications of the results and recommendations for future work.
Chapter 2

Kenya: Country Context

This section provides background information on Kenya’s economy, geography, and climate. It also contains a detailed summary of Kenya’s energy sector, highlighting the existing status and national vision for the future electric power sector.

2.1 Country Overview

Kenya serves as a regional hub for trade and finance in East Africa and leads regional efforts to enhance security in neighboring Somalia and South Sudan. Kenyans face many of the challenges seen in other sub-Saharan African countries, including, lack of access to treated drinking water, sanitation facilities, modern energy services, low literacy rates, high rates of infectious diseases. Large portions of the population living below the poverty line. The Republic of Kenya has proposed an ambitious plan, Vision 2030, to raise the nation to the status of a industrialized, middle-income country through investment in education,
health services, government transparency, infrastructure, and environmental security. In order to meet these goals, Kenyan citizens and businesses need access to clean, reliable energy sources. For this reason, the energy sector is central to the Vision 2030 with a focus on increased development of geothermal, coal, and wind resources as well as the construction of new transmission interconnections with Ethiopia. In addition to infrastructure investments, the plan aims to increase access to electricity to 40% of the population and installed generation capacity to 19,220 GW by 2030 [53]. The current generation capacity is 1,663 GW and estimates of the current access rate range from 16-29% [15, 19, 62] Access to electricity involves both proximity to physical infrastructure and affordability. Given the large low-income population in Kenya, Government officials seek to increase electricity connections without increasing tariffs beyond the reach of low-income consumers.

2.1.1 Economy and Demography

The population is over 41 million with 75% of the workforce in the agriculture sector [5]. Kenya is endowed with many natural resources including extensive hydropower and geothermal power sources, limestone, gemstones, and fertile farmland. A strong tourism industry is fueled by a variety of wildlife and protected parks and major exports include tea and coffee. Despite the political instability in 2007, tourism, trade, and investments from international and domestic firms have helped drive

---

1The range of access rates is probably due to different measuring methodologies and definitions of “access” used by different groups.
an average GDP growth rate of 4.2% over the last ten years [16]. The most populated areas are located in the central and southwest regions of the country, areas most suitable for agriculture (Figure 2-1).

![Kenya Population Distribution](image)

Figure 2-1: Map of population distribution using household densities [68]

### 2.1.2 Geography and Climate

Kenya is a coastal country in east Africa with the Indian Ocean to the east and sharing borders with Tanzania, Uganda, South Sudan, Ethiopia, and Somalia. As an equatorial country, Kenya has an abundant solar resource (discussed further in Chapter 3). Kenya has two rainy seasons: the “long rains” occur from April to June and the “short rains” occur from October to November [68]. The country’s geography varies from low plains along the eastern coast to central highlands. The Great Rift Valley, a region of fertile soil and extensive geothermal
resources, bisects the highlands. The north and north east regions are characterized by desert-like landscapes and arid climate [5]. Existing hydropower plants in the northwest on the Turkana River and along the Tana River in the center of the country benefit from natural drainage resources (Figure 2-2).

![Map of Kenya: Relief and Drainage](image)

Figure 2-2: Map of relief and drainage

### 2.2 Energy Sector

The energy sector has experienced substantial growth in recent years. Private investments in Kenya’s energy sector have increased from $132 million in 2006 to $320 million in 2011[17]. Oil reserves have recently been discovered in the north and the Government has contracted with international firms to explore Kenya’s potential coal resources [25, 55]. These resources, if they prove to be commercially viable, will not be
available for electricity generation in Kenya within the five year time horizon of this study.

Biomass remains the major energy source for 89% of the population, accounting for 68.3% of all energy consumed [68]. Firewood is the most common cooking fuel, particularly in rural areas, and charcoal is the second most popular. In urban areas, kerosene paraffin is often used for cooking. Kerosene is the primary lighting fuel for 73.5% of households. Electricity is the second most common, with 16.4% of households, and collected firewood is third with 6.4% of households. An increased number of affordable solar lighting products in the Kenyan market has led to 1.4% of households using solar products for primary lighting [61]. Estimates of the current electrification rate range from 16.1% to 29% of the population [15, 62]. Access to grid electricity is concentrated in the southern part of the country near Nairobi and the coastal city of Mombassa.

2.2.1 Electricity Sector Structure

Electric power systems consist of generation, transmission, distribution, and retail. There is a spectrum of organizational structures from traditional vertically integrated systems, where one utility serves all functions, to fully decentralized systems, where each function is performed by a separate utility or group of utilities. In addition to structure, power systems vary along an ownership spectrum from fully public to fully private ownership. During the last three decades many power sys-
tems have developed along a path from vertically integrated, publicly owned utilities during early development to decentralized utilities with full or partial private ownership as the system matures.

Kenya is transitioning along this development path. The current electric power system (Figure 2-3) has unbundled generation from the other functions and is transitioning to an independent transmission utility with the newly created company, KETRACO. Private ownership is limited and is mostly found in the generation sector. An independent regulating authority, the ERC, has been created and the Ministry of Energy oversees all activities. Governmental and quasi governmental companies are the key actors in the power sector. The originally state-owned distribution utility Kenya Power and Lighting Company (KPLC) and generator KenGen, are now partially owned by private shareholders. However, the Government of Kenya (GoK) has maintained majority ownership of each of these companies, 50.1% ownership of KPLC and 70% ownership of KenGen as of December 2011 [55].

The key actors in Kenya’s electricity sector are:

- **Ministry of Energy (MOE)**: Responsible for developing energy policies, energy planning, personnel training, and mobilizing financial resources for energy investments.

- **Energy Regulatory Commission (ERC)**: Responsible for economic and technical regulation of electric power, renewable energy, and downstream petroleum sub-sectors. Its functions also include tariff setting, review, licensing, enforcement, dispute settlement
and approval of power purchase and network service contracts.

- **Energy Tribunal**: Quasi-judicial body appointed to hear appeals against the decisions of ERC and any matter relating to the energy sector referred to it.

- **Geothermal Development Company (GDC)**: State-owned company established by the Government as a Special Purpose Vehicle for the development of geothermal resources in Kenya.

- **Kenya Electricity Generating Company (KenGen)**: State Corporation with GoK and private ownership responsible for electric power generation. KenGen produces the bulk of electricity consumed in the country through hydro, geothermal, fuel oil, and
wind plants.

- **Independent Power Producers (IPPs):** Private companies which generate power and sell electricity in bulk to KPLC. As of December 2011, the operating IPPs are:

  - Iberafrica Power (E.A.) Company Limited (thermal power plant)
  - Tsavo Power Company Limited (thermal power plant)
  - Mumias Sugar Company Limited (co-generation)
  - Orpower 4 Inc (geothermal power plant)
  - Rabai Power Company Limited (thermal power plant)
  - Imenti Tea Factory Company Limited (mini-hydro)

- **Kenya Electricity Transmission Company (Ketraco):** A GoK wholly owned company established for the development of the national transmission grid network and facilitating regional power trade.

- **Kenya Power and Lighting Company (KPLC):** State Corporation with GoK and private ownership responsible for the purchase of bulk electricity and carrying out transmission, distribution, supply and retail of electric power.

- **Rural Electrification Authority (REA):** A body corporate with the principal mandate of extending electricity supply to rural areas, managing the rural electrification fund, mobilizing resources
for rural electrification and promoting the development and use of renewable energy.

### 2.2.2 Generation Technologies

In the electricity sector, regulatory and structural reforms during the 1990s to unbundle services and permit private participation in the market have led to significant increases in generation capacity (Figure 2-4).

![Generating Capacity in Kenya 1980-2011](image)

Figure 2-4: Public and private sector ownership of generation assets

[17]

The total generating capacity is 1,663 MW and the system peak demand is 1,228 MW [65]. Kenya also has interconnections with neighboring Uganda and Tanzania and has been a net importer of electricity since 2006. Historically, the electric power system has relied heavily on hydropower with almost 80% of installed capacity coming from hydropower until 1996 [7]. Recent investments in new generating capacity have focused on geothermal and conventional thermal plants, reducing
the share of hydropower to 47% [65]. Table 2.1 below contains all major generation plants in the country. Generation from hydropower made up 45% of total generation in 2011. Fuel oil plants fueled by kerosene or heavy fuel oil are the second largest source of generation, providing 38% of total installed capacity and 25% of generation. Geothermal plants currently make up 13% of total capacity and produced 24% of total generation. Wind and cogeneration plants make up the remaining 2% of generating capacity and provided less than 2% of total generation. The remaining load is met through imports from Tanzania and Ethiopia. Since 2000, Kenya has been contracting with emergency power producers (EPPs) to provide additional generating capacity during periods of poor hydrology or unscheduled outages. Currently, 120 MW of diesel capacity is provided by an EPP [65] for an annual leasing cost of over $35 million.

<table>
<thead>
<tr>
<th>Generator Type</th>
<th>Capacity (MW)</th>
<th>% of Total Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geothermal</td>
<td>208</td>
<td>12</td>
</tr>
<tr>
<td>Gas Turbine (Kerosene)</td>
<td>60</td>
<td>4</td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>576</td>
<td>28</td>
</tr>
<tr>
<td>Hydro</td>
<td>788</td>
<td>47</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>26</td>
<td>2</td>
</tr>
<tr>
<td>Wind</td>
<td>5.3</td>
<td>-</td>
</tr>
<tr>
<td>EPP (diesel)</td>
<td>120</td>
<td>7</td>
</tr>
<tr>
<td><strong>Total Generation</strong></td>
<td><strong>1,663</strong></td>
<td><strong>100</strong></td>
</tr>
</tbody>
</table>

Table 2.1: 2012 Generation Mix

Despite large investments in generating capacity the system suffers from frequent supply interruptions due to technical failures and variability of the hydropower resources. During the period from January
2011 to June 2012, there were 238 load shedding events recorded by KPLC. In order to assess the leading causes of these events, I grouped the explanations provided by KPLC for each occurrence into four categories. As shown in Figure 2-5, the dominant source of load shedding was “out of commission” (OOC) generating units that result in reduced output. The majority of these occurrences, over 70%, were in geothermal, cogeneration, or conventional thermal plants. The remaining OOC events occurred in hydro plants. The second most common cause for load shedding was insufficient hydro inflows or deliberate curtailment of hydropower generation to conserve water. Network interruptions and miscellaneous events such as vandalism or fires account for the remaining load shedding events. It is important to note that in many cases there were multiple contributing causes to a single load shedding event. For example, cases where poor hydrology led plant owners to curtail output from hydropower plants were often recorded as “OOC” and “Insufficient Inflows”. Overall, lack of available capacity in the generation sector - not the transmission or distribution sectors - was the leading cause of load shedding events during this period. This uncertainty in supply was largely due to unavailable thermal units or poor hydrology.

2.3 Looking Forward: National Expansion Plan

System planners in Kenya forecast peak demand of 15,000 MW by 2030, a twelve-fold increase of the current peak demand. A key challenge to meeting growing demand is the need for new sources of generation.
There are limited remaining large-scale hydropower resources left in the country that do not pose environmental concerns and increasing variations in inflows due to climate change effects make hydropower an unappealing option for new generation investments. Currently, only two large hydropower projects with a total capacity of 200 MW are being considered. Expanded use of fuel oil plants is also undesirable due to their high running cost and the lack of domestic fuel resources which leaves consumers vulnerable to price spikes. Kenya has very good wind resources and independent power producers have proposed over 600 MW of wind power projects. These resources are highly localized far from load centers and uncertainty surrounding the construction of necessary transmission infrastructure and access to finance has proven challenging for these projects and it is unclear if any will be developed [44]. Oil and coal reserves are currently being explored but these
resources remain years away from commercial production and their potential is unclear. Geothermal is the most promising domestic source of energy being considered. Current estimates suggest between 5,000 and 10,000 MW of geothermal capacity could be developed over fourteen sites [55].

The national development plan for the power sector aims to increase total installed generating capacity to 21,620 MW by 2031 from the current capacity of 1,663 MW. Geothermal, nuclear, and coal power plants will dominate the new generation mix. Table 2.2 contains the projected generation mix proposed in the development plan.

<table>
<thead>
<tr>
<th>Generator Type</th>
<th>Capacity (MW)</th>
<th>% of Total Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geothermal</td>
<td>5,530</td>
<td>26</td>
</tr>
<tr>
<td>Nuclear</td>
<td>4,000</td>
<td>19</td>
</tr>
<tr>
<td>Coal</td>
<td>2,720</td>
<td>13</td>
</tr>
<tr>
<td>Gas Turbine (LNG)</td>
<td>2,340</td>
<td>11</td>
</tr>
<tr>
<td>Wind</td>
<td>2,036</td>
<td>9</td>
</tr>
<tr>
<td>Imports</td>
<td>2,000</td>
<td>9</td>
</tr>
<tr>
<td>Medium Speed Diesel</td>
<td>1,955</td>
<td>9</td>
</tr>
<tr>
<td>Hydro</td>
<td>1,039</td>
<td>5</td>
</tr>
<tr>
<td><strong>Total Generation</strong></td>
<td><strong>21,620</strong></td>
<td><strong>100</strong></td>
</tr>
</tbody>
</table>

Table 2.2: 2031 Projected Generation Mix [55]

While the proposed expansion plan would significantly increase Kenya’s generating capacity and improve system reliability through an increased reserve margin, there remain many significant hurdles. Security and financial risks associated with nuclear power development are large. Though many countries have proposed to develop nuclear plants, South Africa remains the only sub-Saharan African country with nuclear power [7]. As discussed earlier, the availability of domestic coal and petroleum
resources is uncertain. If domestic resources cannot be developed or are insufficient, these plants will remain dependent on imported fuels. The significant increase in imported power is based on a proposed interconnection with Ethiopia to be developed from 2014-2020. This connection will allow Kenya to import excess power produced by Ethiopia’s hydropower plants. However, it is not clear if this excess power will be available nor how the two countries will negotiate the power exchange.

The planned expansion will require significant investments in transmission capacity because many of the proposed geothermal, diesel, and wind sites are far from major load centers. Figures 2-6a and 2-6b show the current and projected locations of electricity demand and generation centers. Large amounts of nuclear and traditional thermal power that must be sited at the coast will outstrip regional demand. Geothermal power is also geographically restricted to the central and eastern parts of the country where demand is low. The interconnection with Ethiopia will require a 600 km transmission line, passing through some of the least populated parts of the country.

Significantly for this study, large-scale solar power plays no role in Kenya’s most recent power sector expansion plan despite a significant solar resource. Solar power is only mentioned in the context of small-scale applications such as solar lanterns and solar home systems and large-scale solar projects are considered prohibitively expensive. However, the report used pricing data from 2003 for solar modules and the price of crystalline silicon PV modules have decreased significantly
The mismatch of load and generation experienced in the existing system (a) is projected to increase under the current expansion plan (b).

since 2003 from around $4 per Watt to less than $1 per Watt in 2012 [28, 36]. The decrease in solar prices and increase in fuel costs could
make solar a viable option in Kenya. The following chapter describes Kenya’s solar resource and potential solar power technologies.
Chapter 3

Solar Technologies and Resources

3.1 Solar Technologies

There are two primary types of solar technology mature enough for commercial-scale deployment. These are solar photovoltaic (PV) and concentrating solar power (CSP). A general overview of these two categories is provided below.

3.1.1 Solar PV

The photovoltaic effect, discovered by Becquerel in 1839, enables electricity generation from incoming solar energy. Bell Laboratories applied this principle to create the first photovoltaic cell in 1954 [43] and ongoing research has continued to improve cell performance. A detailed discussion of photovoltaic physics can be found in [40].

The first generation solar cells were developed with crystalline silicon (c-Si) as the semiconducting material. These cells are the most common
today due to their relatively high efficiencies of 15-17% and have over 80% of the market share [26]. Later generation cells have attempted to use less expensive materials and thinner cells to generate electricity. This group, referred to as thin-film PV, tend to have lower efficiencies than c-Si cells. The most common thin film cells are amorphous silicon (a-Si), cadmium telluride (CdTe), and copper indium gallium selenide (CIGS).

Historically, PV deployment has been slowed by real or perceived challenges such as high capital costs, lack of scale in manufacturing, shortage of raw materials, and balance of system (BOS) performance limitations. Recent reductions in cell prices, increased manufacturing and more aggressive policies have driven a rapid growth in installed global solar PV capacity. Annual growth in installed PV has averaged over 58% since 2006. By the end of 2011, the total world PV capacity stood at 70 GW [34].

3.1.2 Concentrating Solar Power

By contrast, concentrating solar power (CSP) technologies do not use the photovoltaic effect to generate electricity but resemble more traditional fossil fuel-based technologies that use Rankine or Stirling cycles to convert heat to work. CSP focuses incoming solar energy onto a heat transfer fluid which uses a heat exchanger to produce steam in the Rankine cycle or isothermal expansion in the Stirling cycle to create...
mechanical torque and drive a generator, producing electricity. CSP technologies can vary significantly in the method used to collect and focus the solar rays onto the working fluid. The most common designs are linear concentrators, dish/engine systems, and power towers.

Potential locations for CSP plants are more limited than PV technologies because these plants require water for cooling and a large contiguous area to collect direct normal insolation (DNI), solar radiation striking normal to the reflecting surface, to heat the working fluid and create steam. Parabolic troughs and solar tower designs, which use the Rankine cycle, require around 750 gallons per MWh for wet cooling and 80 gallons per MWh for dry cooling. While dry cooling techniques can significantly reduce water requirements, existing designs result in decreased plant efficiency and slightly higher costs [46]. Dish/engine systems that use the Stirling cycle only use water for washing the reflective surfaces, around 20 gallons per MWh [8]. CSP offers the potential for thermal storage which could be used to compensate for solar intermittency or align electricity production to match peak hours. Currently, the world CSP capacity is over 2.5 GW [34].

3.1.3 Solar Technologies Chosen for the Study

For this initial study of solar power in Kenya, we have chosen to only consider solar PV technology. The reasons for excluding CSP are as follows: 1.) potential sites for CSP plants are limited to areas of high
DNI which are far from major load centers in Kenya, 2.) the large water requirements of CSP technologies, 3.) the economics of CSP plants favor large plants requiring large upfront investments in land and capital and 4.) CSP is a relatively new technology with only parabolic troughs and power towers past the demonstration stage.

Unlike PV plants which can capture and use direct and indirect sunlight, CSP plants can only utilize direct solar radiation. Areas with DNI values of 6 kWh/m\(^2\)/day or greater are considered strong candidates for concentrating solar power applications. The total area available in Kenya for this type of generation is approximately 106 km\(^2\) with a generating potential of 638 TWh [68]. However, the regions with the greatest DNI potential are located in the north of the country, far from major load centers in the south (Figure 3-1) and would require large investments in transmission infrastructure.

The large water requirements of some CSP plants impose additional site restrictions for potential plants. Perhaps more importantly water resources in Kenya are not evenly distributed and water scarcity effects over 35% of the population [70]. New power plants with large water requirements may further exacerbate the problem, particularly if they are placed in the arid north.

In addition to resource constraints, CSP projects offer less flexibility in their size favoring larger plants (capital costs for for 100-200 MW plants can be 10-20% less than a 50 MW plant [13]). Unlike PV plants where capacity can be added incrementally to meet growing demand,
CSP investments are lumpy requiring large upfront investments. With limited domestic financing available and potentially high demand risk in the near term, project developers may find it difficult to find investors for such projects in many developing countries.

Finally, some CSP technologies are relatively new and still in development. Parabolic troughs are the only technology to be proven commercially with storage and currently make up 94% of the market.
Storage for solar towers is commercially ready and pilot projects have been deployed. Dish/engine designs are still in the demonstration stage and storage for these systems has not been proven. I believe the relative inexperience with these technologies may complicate any performance, cost, and financing projections in Kenya.

This is not to say that CSP is not a viable option for Kenya in the future. Current projects underway in South Africa will increase the knowledge base for cost, financing, and performance of CSP projects in Africa. Additionally, Kenya’s daily demand peaks in the evening hours and this peak may continue to grow as the rates of electricity access among residential consumers increases. CSP technologies able to store power for several hours could displace the need for some fossil-fuel based generators during the evening. More information on CSP technologies and costs can be found in [13, 8].

3.1.4 Cost of Solar

Solar power in general is characterized by high upfront capital investment and very low variable cost of generation. High upfront costs associated with solar technologies have been a significant barrier to solar power deployment in the past. Solar power is not economically viable in any market without significant policy support via feed-in-tariffs, capital subsidies, or tax rebates, for example. However, increased economies of scale in manufacturing, lower levels of perceived risk among financiers, and technology innovations have contributed to significant reductions
in project costs. Additionally, increased fuel costs for some fossil fuel-based generators have increased the economic competitiveness of solar PV.

The three most common metrics used to characterize the cost of solar power are the levelized cost of energy (\$/kWh), ‘grid parity’, and the price per watt (\$/W) [20]. The usefulness of each metric depends on the available data, audience, and its intended application. An overview of each cost metric is provided below followed by a discussion of the method used in this study.

**Levelized Cost of Energy**

The levelized cost of energy (LCOE) is the total life-cycle cost of a power plant spread over the expected generation output of the plant during its lifetime. A basic formulation of LCOE for a particular year is as follows:

\[
LCOE = \sum_{t=1}^{N} \frac{I_t + F_t + V_t}{E_t}
\]  

(3.1)

where \(I_t\) is the plant’s investment cost, \(F_t\) is the annual fixed cost, \(V_t\) is the variable cost including fuel and operation and maintenance, and \(E_t\) is the expected generation output. \(N\) is the lifetime of the plant, usually 20 years, and \(t\) is the year. LCOE comparisons are valuable for side-by-side comparisons of candidate technologies. Assumptions
about available financing, incentives, component costs, and payment methods are captured by $I_t$ and $E_n$ contains assumptions about system performance and the available solar resource. Work by [20] identify four factors that have the largest influence on LCOE values. These are cost of capital, cost of equity, cost of debt, and capacity factor. It is significant to note that only one of these factors, the capacity factor, is related to the available solar resource and technology performance. The others could be classified as institutional and are dependent on perceived investment risk and the strength of regional financial institutions. This has particular salience in the developing country context where an abundant solar resource may exist but weak financial, regulatory, or industrial institutions may lead to underinvestment in solar power.

The LCOE may be best presented as a range of values instead of a point value due to the variation in contributing factors discussed above. The values used in Kenya’s power sector planning documents, based on price data from 2003, estimate LCOE values of $122 - 222$ per MWh. Figure 3-2 below contains an updated comparison of LCOE values for grid-connected solar PV technologies with major generation technologies present in Kenya. The yellow lines represent the global average value. As shown in the figure, grid-connected solar PV in Kenya may already be competitive with diesel power plants.
A shortcoming of LCOE comparisons is that they fail to account for the added value of a candidate technology in the context of a particular system and penetration level of the technology. For example, the added value of a solar PV plant could be higher in a system where peak demand coincides with solar output or added solar generation can displace a more expensive existing generation source. The penetration level of the candidate technology can also affect its added value. A generation system composed of inflexible nuclear plants would benefit more from the addition of a flexible gas turbine technology than another nuclear unit. LCOE values - independent of temporal or operational relationships in the system - do not capture these system-level benefits.

**Grid Parity**

The metric of grid parity is often used to evaluate the cost competitiveness of a generation technology in the context of a specific market
segment. The economic value of adding solar PV to the generation mix depends on the nature of the demand, market structure, ability of existing technologies to compensate for intermittency, injection point in the grid where solar power will be added, and electricity price. In most cases, grid parity simply refers to the comparison of retail solar prices to the last component, electricity prices. As with LCOE comparisons, this fails to account for the potential added value that solar could provide to the power system as a whole. Additionally, it potentially compounds other tariff elements into the comparison that may not be relevant. For example, Table 3.1 below contains an estimated annual tariff rate for consumption groups in Kenya. As seen in the tariff schedule, a large portion of the retail tariff is composed of charges not associated with electricity generation.

<table>
<thead>
<tr>
<th>Item</th>
<th>Domestic</th>
<th>Commercial Small</th>
<th>Commercial Large</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Charge</td>
<td>(KES/year)</td>
<td>1440</td>
<td>1440</td>
<td>11,910</td>
</tr>
<tr>
<td>Consumption Charge</td>
<td>(KES/year)</td>
<td>5,250</td>
<td>123,648</td>
<td>3,147,114</td>
</tr>
<tr>
<td>Fuel Cost Adjustment</td>
<td>(KES/year)</td>
<td>6,028</td>
<td>75,624</td>
<td>3,233,200</td>
</tr>
<tr>
<td>Foreign Exchange Adj.</td>
<td>(KES/year)</td>
<td>1,518</td>
<td>19,044</td>
<td>814,200</td>
</tr>
<tr>
<td>Inflation</td>
<td>(KES/year)</td>
<td>242</td>
<td>3,036</td>
<td>129,800</td>
</tr>
<tr>
<td>ERC levy</td>
<td>(KES/year)</td>
<td>33</td>
<td>414</td>
<td>17,700</td>
</tr>
<tr>
<td>Rural Electrification</td>
<td>(KES/year)</td>
<td>712</td>
<td>10,988</td>
<td>360,321</td>
</tr>
<tr>
<td>Total Costs</td>
<td>(KES/year)</td>
<td>15,223</td>
<td>234,194</td>
<td>7,714,244</td>
</tr>
<tr>
<td>Average Consumption</td>
<td>(kWh/year)</td>
<td>1,100</td>
<td>13,800</td>
<td>590,000</td>
</tr>
<tr>
<td>KES/kWh</td>
<td>13.84</td>
<td>16.97</td>
<td>13.07</td>
<td>11.90</td>
</tr>
<tr>
<td>USD/kWh</td>
<td>0.16</td>
<td>0.19</td>
<td>0.15</td>
<td>0.14</td>
</tr>
</tbody>
</table>

Table 3.1: Average electricity costs per consumer group [14]

While grid parity comparisons based solely on electricity tariffs are not an appropriate measure for power sector investment decisions, a
carefully designed comparison that isolates different elements of the tariff could be successfully employed. For example, solar home system users could be charged separately using two meters for energy and network usage allowing the utility to recoup the costs of maintaining the network while consumers benefit from reduced energy purchases from the central grid. Though grid parity comparisons could be used to inform investment decisions, this technique is not straightforward and care must be taken to ensure that the comparison does not confound unrelated elements of the electricity price.

**Price per Watt**

The price per watt is often used as a benchmark for production costs of solar technology. The main cost drivers for solar PV systems are the solar module, installation, financing, charge controller, and balance of system (e.g. batteries, mounting structures, inverters). PV module prices have decreased significantly from over $50 per Watt in the 1970s to $0.88 per Watt in 2012 (Figure 3-3). Total costs for utility-scale systems ranged from $2.24 to almost $5 per Watt in 2012 [75]. While regional variations exist, improved racking systems and increased experience have contributed to reduced installation, maintenance, and financing costs. Balance of system (BOS) costs have fallen at a slower rate than modules and now make up the majority share of total system costs [20]. However, analysis by the Rocky Mountain Institute
recently estimated that BOS costs could achieve further reductions of 50% through improvements in structural design and better standardization across the industry resulting in reduced material costs, labor time, and the need for specialized tools [24].

![Figure 3-3: PV module experience curve 1976-2011](image)

Price per watt comparisons of system components can be confusing since it is unclear if quoted figures indicate manufacturing cost, the wholesale price, or the retail price. Additionally, these values do not include location specific factors such as freight, solar resources, or incentives such as a feed in tariff or capital subsidies.

**Cost Metrics Developed for this Study**

This thesis aims to determine if solar PV is an economic investment decision in Kenya’s power system. In other words, do the avoided costs the power purchaser would otherwise have to pay for the same level
of generation and reliability requirements justify investments in solar PV? For reasons discussed above, none of the three previous metrics are appropriate to capture the effect of added solar generation on system-level costs. Instead, this study will use the avoided costs of generation with a given level of solar capacity to determine the investment cost of that solar plant and average variable costs that system operators could pay for the solar generation. These values will be compared with investment costs experienced in similar markets and proposed feed in tariffs in Kenya to determine if solar PV plants are a cost effective investment.

3.2 Available Solar Resource in Kenya

Located astride the equator, Kenya receives a significant amount of solar radiation throughout the year. Until recently, there were limited data available on annual radiation levels. The most complete data set available to policy makers and project planners were solar maps generated by NASA using spatial grids of 100 km x 100 km [3]. These data sets lack the spatial resolution and time series data required to conduct a feasibility study of large-scale solar projects. In 2008, a detailed solar resource assessment was published by Solar and Wind Energy Resource Assessment (SWERA), combining satellite data with a spatial resolution of 5 km x 5 km and measurements from 23 ground-based sites. These data, collected from 2000-2002, provide increased resolution and hourly time series information. The ground based sites are spaced throughout the country, covering a variety of geographic
conditions, with additional measuring stations near major load centers (Figure 3-4).

![Figure 3-4: Location of ground-based measurement sites for solar radiation](image)

This study uses the average hourly radiation value from the ground sites over the measuring period to characterize the solar radiation that can be expected for a proposed plant. A shortcoming of this methodology is that values averaged over multiple years and multiple locations will tend to mask two key features of solar electricity generation: variability and uncertainty. Variability describes changes in insolation over time, whether on an hourly or minute-by-minute scale. Since solar PV plants cannot use thermal inertia for energy storage like CSP plants, the variability is solar radiation will directly affect the generation output. Potential variations in output have direct implications for the ramping requirements of other technologies to ensure voltage stability. Uncertainty describes the spatial variation in insolation levels. Cumu-
lative radiation on a regional or country level do not capture variations across different sites at a plant level. For example, Figure 3-5 contains ground-based insolation data collected hourly for three measuring stations over two days and the average value. As seen in the figure, the average value (in purple) tends to smooth variation and uncertainty that would be experienced by an actual plant.

For additional studies that consider a multi-node system where plants are located at a specific site in the electricity network, accurate locational radiation data for proposed plants is recommended.

![Variation and Uncertainty in Hourly GHI values](image)

Figure 3-5: Variation and uncertainty in solar insolation

[68]

The SWERA assessment measured both direct normal irradiance (DNI) and global horizontal irradiance (GHI). DNI resources, relevant for CSP, were discussed above. GHI measures the total radiation received on a surface from direct and diffuse light and is of interest for solar PV applications. Figure 3-6 contains the average daily sum global
horizontal irradiance. GHI resources are strongest along the eastern half of the country and in the north near. In addition to regional variations, Kenya’s solar radiation also varies by month. The monthly solar variation corresponds with the rainy season, with reduced solar radiation during the two rainy seasons (Figure 3-7).

Figure 3-6: Three year average daily sum Global Horizontal Insolation (GHI) (kWh/m²/day) [68]
Figure 3-7: Average monthly GHI variation (kWh/m²/day) [68]
Table 3.2 below contains a summary of the solar resources available by irradiance class. Generating potential from solar photovoltaic applications, which can be used with any GHI level, total over 4,500 TWh.

<table>
<thead>
<tr>
<th>Irradiance Class (kWh/m²/day)</th>
<th>GHI Area (km²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.25-3.5</td>
<td>53,244</td>
</tr>
<tr>
<td>3.5-3.75</td>
<td>79,417</td>
</tr>
<tr>
<td>3.75-4.0</td>
<td>72,485</td>
</tr>
<tr>
<td>4.0-4.25</td>
<td>65,089</td>
</tr>
<tr>
<td>4.25-4.5</td>
<td>93,007</td>
</tr>
<tr>
<td>4.5-4.75</td>
<td>87,634</td>
</tr>
<tr>
<td>4.75-5.0</td>
<td>75,624</td>
</tr>
<tr>
<td>5.0-5.25</td>
<td>81,086</td>
</tr>
<tr>
<td>5.25-5.5</td>
<td>65,285</td>
</tr>
<tr>
<td>5.5-5.75</td>
<td>121,378</td>
</tr>
<tr>
<td>5.75-6.0</td>
<td>75,615</td>
</tr>
<tr>
<td>6.0-6.25</td>
<td>8,404</td>
</tr>
<tr>
<td>6.25-6.5</td>
<td>8,272</td>
</tr>
<tr>
<td>6.5-6.75</td>
<td>48,505</td>
</tr>
<tr>
<td>6.75-7.0</td>
<td>26,378</td>
</tr>
</tbody>
</table>

Table 3.2: Solar energy available
[68]
Chapter 4

Previous Work

This chapter offers a brief review of previous studies relevant to this thesis. Much of the literature on regulatory and technical implications of intermittent renewables on the electric grid have tended to focus on wind power. However increasing levels of grid-connected PV penetration have prompted policy-makers and system planners to increase their focus on the effects of solar PV. Additionally, these studies have focused on the US and European markets with limited regulatory and technical assessments being conducted in developing countries. This overview of previous work can be divided into three areas: 1. regulatory and technical implications of large-scale deployment of solar PV, 2. modeling methodologies developed to incorporate intermittent sources in power system models, and 3. assessments of solar potential in Kenya.
4.1 Regulatory and Technical Assessments

A wide range of renewable integration studies exist for different global regions but there were limited comprehensive studies focused on Kenya or sub-Saharan Africa. This review will highlight recent studies and recommendations for the US system that can be translated to the Kenyan experience.

The US Department of Energy commissioned a series of studies on the impact of high levels of PV in the US power system. These studies [21, 2, 32] cover a large area of interest including the impacts of PV on generation planning, transmission planning, and production cost modeling. They conclude that most traditional power system planning tools were designed for vertically integrated utilities without intermittent renewables. As the levels of PV penetration increase, planners will need to rethink the way they treat demand, modeling PV generation as part of the load and planning for “net load”. Transmission and distribution networks will need to be viewed as dynamic systems susceptible to quick voltage changes if available PV generation fluctuates. Additionally, the authors suggest the traditional method of production cost modeling is not suitable for solar PV and the actual value of added solar capacity on a system should include contributions from avoided fuels and emissions across different generation mixes. A key operational concern raised by [21, 23] is the increased level of intermittency on the grid due high levels of solar PV. Suggestions to overcome this include increased levels of reserve capacity, improved weather forecasting, and
better realtime voltage control devices.

Also relevant to the Kenyan system, [11] emphasized the important role reservoir hydro plants can play to facilitate larger levels of intermittent renewables such as wind and solar.

4.2 Current Modeling Tools

There exists a wide range of power system models designed to meet different needs in both time scales and the power system elements included in the model. The most common types of models are expansion planning, hydro-thermal coordination, production cost models, unit commitment, economic dispatch, optimal power flow, and network stability. Expansion planning models use multi-decade time scales to optimize investment decisions in generation, transmission, or both. At the other end of the temporal spectrum, transient stability analysis models use sub-second time scales to monitor network flows. Hydro-thermal coordination, production cost, unit commitment, and economic dispatch models seek to optimize generation output in the medium-term. The objective function of these models is generally cost minimization but constraints such as carbon emissions, limitations on plant start-ups and shut downs, or water conservation can also be applied. If the transmission network is omitted, these models are referred to as single node with the generation and load assumed to be in the same location. Multi-node systems include the transmission network and locations of generation plants and load centers. Optimal power flow models are used
in multi-node systems to include constraints imposed by the transmission network into the optimization problem.

An overview of decision support tools is provided by [66, 63]. In hydrothermal systems, hydrothermal coordination tools are used for generation scheduling in the medium-term to manage the use of low-cost hydro resources. [77] provides an overview of generation scheduling methods for both regulated and deregulated markets. The representation of stochastic variables, such as hydro inflows, is also a key area for medium and long term planning. An overview of stochastic programming and its applications to power system models can be found in [38, 45].

While the previous works provide an overview of current decision support tools and methodologies used in power system modeling, I would like to highlight three specific models: ReEDS, VALORAGUA, and WASP. ReEDS serves as an example of one of several models commonly used by researchers in the US to evaluate integration of renewable energy technologies in existing power systems. VALORAGUA and WASP are have been widely used international and they are currently used by system planners in Kenya. A review of energy system models and their applicability to developing countries can be found in [22].

The Regional Energy Development System (ReEDS), developed by NREL is a cost-minimizing model designed for long-term generation, storage, and transmission expansion planning. ReEDS can be a powerful expansion planning tool for system planners looking to incorporate
renewable energy technologies into their power systems due to the high level of spatial resolution data available on wind and solar resources. However, the model is developed for power systems in the US and introducing international resource and network information is not trivial. More information on the ReEDS model can be found in [67].

VALORAGUA is a commercially available hydrothermal coordination tool currently in use in Kenya. The in an operational model that represents uncertainty in hydro inflows through three sets of hydrological conditions: dry, average, and wet. VALORAGUA is a powerful tool to solve hydrothermal optimization problems by evaluating the value of water over a one-year horizon. The year can be divided into periods of one month or one week and uses five load steps to represent demand levels from peak (first load step) to base load (fifth load step) [73].

For Kenya’s long-term expansion planning the outputs from VALORAGUA are used as input into the Wein Automatic Simulation Planning Package (WASP). WASP is a probabilistic planning tool designed to determine the lowest cost generation expansion plan for a variety of input conditions such as different hydrological scenarios. WASP also uses a simplified representation of the load in place of a chronological load representation. The projected demand in WASP is defined by a load duration curve, where the total annual load is arranged in descending order of magnitude regardless of the temporal relationship between when the projected loads occur. Current system plans do not include solar PV as a candidate generation plant and it is not clear from the
A shortcoming of reducing the load into load steps or load duration curves is the loss of hourly chronology. With traditional generation technologies that can operate any time of day, there is no need to match the chronological dependence on the time of day demand and available generation. However, with the introduction of intermittent renewables such as solar and wind that only generate during certain times of day hourly matching of time of day generation and demand becomes important. Additionally, a chronological model of the system is able to capture all start up and shut down decisions for each plant, something that cannot be included in load block representations. The costs associated with these decisions can be significant and increased penetration of intermittent renewables have been shown to increase these costs in many systems [41].

4.3 Assessments of Solar Power in Kenya

As mentioned previously, discussion of solar PV in Kenya has almost exclusively been relegated to off-grid applications due to its high capital costs and the availability of large hydro and geothermal resources. [68] provides an assessment of the solar resource in Kenya and the Government’s Scaling-Up Renewable Energy Program (SREP) outlines the country’s medium-term renewable energy investment priorities [54]. SREP’s focus is on efforts develop a governing regulatory framework for increased deployment of solar water heating systems and a small
number of projects to deploy hybrid solar and wind systems for off-grid power for rural health clinics, schools, water pumps, and lighting. [49] discusses the market potential, financing and delivery models for deploying solar PV in Africa. The paper only considers only off-grid applications and predicts solar PV will continue to be a “niche market” with high capital costs and limited applications.

There is limited literature on the technical and economic feasibility of large deployments of grid-connected solar PV. The only study of grid-connected solar PV in Kenya found during this research was [42]. This study assessed the technical and economic feasibility of net metered solar home installations and found that solar will be cost-competitive with electricity from the central grid within two years for consumers classes that use 1500 kWh/month or more. The authors find that 200 MW of rooftop solar can feasibly be added to the system with no threats to grid stability and the potential of lost profits to KPLC can be eliminated through a “net metering fee” for consumers with solar PV systems.

The majority of literature on large scale solar deployment in the country focuses on identifying existing barriers for investment. A discussion of these barriers is provided by [68, 27, 42]. These barriers are associated with resources, regulations, and risk. Resource barriers refer to both a lack of accurate solar resource data as well as limited availability of financial capital and low awareness of opportunities among potential investors. Price distorting subsidy schemes for fossil fuels,
a lack of transparency during power purchase agreement (PPA) negotiations, and a feed-in-tariff that is too low to attract investment are included in the list of regulatory barriers. Finally, there are country risks for outside investors such as the ability to repatriate profits, exchange risk, and the ability to arbitrage in the case of contract disputes.

[68, 27, 42] offer recommendations to spur investment in grid-connected solar PV. These include continuing the existing VAT tax exemption for solar products, increasing transparency of the PPA process, and increase the speed and transparency for IPPs to obtain grid connections. Importantly for this study, the authors also recommend updating the modeling methodology used in the current development plan to evaluate candidate technologies to accurately describe the cost of fossil fuel plants.

4.4 The Need for a New Model

Currently, long-term planning is made with the assistance of multiple models including VALORAGUA and WASP discussed above which lack the hourly time-scale required for the evaluation of added solar generation. The potential to interoperate reservoir hydro and solar PV plants to overcome solar’s intermittency is relatively new and existing models being used in Kenya and other African countries with large amounts of reservoir hydro and solar resources are not designed to evaluate it. Additionally, the operating assumption behind the inputs to many expansion planning models, such as WASP is the evaluation of
candidate technologies on a project – rather than system – level. In Kenya, screening curve comparisons were used to evaluate which candidate technologies should be considered included in WASP [55]. This type of analysis is not appropriate for renewable energy technologies such as solar and wind and, as mentioned by [32], the value of added solar capacity is best evaluated from a system perspective.

For the reasons outlined above, a new type of flexible assessment tool is needed to evaluate the value of adding renewables, such as solar PV, onto the Kenyan grid.
Chapter 5

Model Methodology and Formulation

Previous chapters have provided an overview of Kenya’s electric power system, solar resource, and a review of relevant previous work. This chapter outlines the modeling methodology developed for this thesis.

The choice of model type depends heavily on the question being asked and level of detail required. The goal of this thesis is to evaluate the technical and economic feasibility of grid-connected solar power to address generation shortfalls in Kenya’s existing system and meet growing demand as part of their future generation mix. Additionally, I would like to investigate what factors—demand, solar price, fuel price, or hydrological conditions—may affect the economics of solar in Kenya.

With this in mind, a model of the Kenyan system was designed with the following characteristics:

- **Single node**: The single node system was chosen because it addresses the primary question of whether solar generation is com-
petitive with other candidate technologies without concern for location or network constraints that will need to be considered later. Additionally, as mentioned in 2.2.2, the majority of load shedding events were caused by shortfalls in generation and not network constraints.

- **Partially Stochastic:** The largest source of uncertainty in the Kenyan system is fluctuations in hydro inflows. These variations are modeled using scenario analysis of different inflow conditions. Solar insolation, wind speeds, demand, and fuel prices are modeled deterministically. This was a simplifying assumption made in order to allow a top-level system analysis. In order to assess the value of uncertainty in these variables, sensitivity and scenario analyses were conducted. However, real investment decisions are made in the face of uncertainty and recommendations for future work include methods to include further stochasticity into the model.

- **Static expansion planning:** Two static expansion planning models were developed to evaluate the optimal generation mix in 2012 and 2017 independently. The representation of a static year may be appropriate for an initial evaluation of a technology. If this assessment indicates that the technology is a feasible candidate in the future system, then a dynamic expansion planning model can be used to determine the optimal investment schedule. The hourly periods were chosen to capture the temporal relationship between solar generation and demand.
• **Hydrothermal coordination:** Hydropower has a very low variable cost and a standard economic dispatch model would tend to maximize generation from these plants without consideration that water used this month may be more valuable next month. Hydrothermal coordination models optimize the yearly operation of thermal and hydro power plants, taking into account the value of stored water in reservoirs. This model also assess potential coordination of hydropower with solar generation.

• **Unit commitment:** After the unit commitment decision is made, each assigned plant is dispatched based on lowest cost criteria subject to technical constraints specific to each plant.

This model can be run in two modes: expansion planning and unit commitment. In the existing 2012 system, all investment decisions have been made and this model is run in unit commitment mode only. The objective of the unit commitment model is to obtain an hourly schedule for each generating set under different assumed generation mixes as to meet system demand at minimum cost. The analysis of Kenya’s projected 2017 system involves both expansion planning and unit commitment decisions. The expansion planning problem is solved first in order to determine which plants should be built to meet projected demand followed by the secondary unit commitment problem. This work was done with the General Algebraic Modeling System, GAMS, that provides a high level modeling platform for mathematical programming and optimization problems. The models, titled UC2012 and UC2017,
were adopted from ICAI School of Engineering at Universidad Pontificia Comillas, Madrid. The following sections will provide a description of the model inputs, equation formulation, and limitations of the model.

5.1 Model Formulation

5.1.1 Generator Constraints

All generation plants are subject to certain technical constraints. These constraints account for the fact that all technologies are not perfect substitutes and unit commitment decisions must consider the complex interactions between different technologies, accounting for such things as different ramping rates, start up and shut down costs, and hours of available generation in the case of solar or wind. As a result, the optimal solution may vary from the least-cost dispatch solution for an individual period taken alone. For example, it may be optimal to keep a diesel generator running at its minimum allowable load when there are alternative plants available with cheaper marginal costs to avoid the added costs of shutting down and starting up the diesel plant. This section will outline the constraints imposed on all generation units included in the model.

Net Power

All power plants consume some level of generated power for some in-house use for auxiliary services. Thus the total capacity available to the grid, net power, is less than the total power being produced
by the generator, gross power. An auxiliary load factor, $k$, specific to each power plant is used to account for all in-house and is included separately in the optimization problem.

The term $Q$ is used to designate the production capacity of the unit. In addition to in-house use each plant is unavailable for certain periods during the year due to scheduled maintenance or unscheduled outages. Ideally, the actual maintenance schedule would be used to specify which plants will be unavailable during specific periods. This information was not available, however, leading us to follow the method used the Kenya’s national planning documents [55] and derate each plant’s available generating capacity by a factor, $out$. Therefore, the maximum effective capacity of each plant is given by:

$$Q_{max} = Q_{avail} \times out$$

(5.1)

**Upper and lower output limits**

When making unit commitment decisions, it is important to consider the minimum and maximum generation output achievable by each plant. Plants cannot produce power above their maximum effective capacity, $Q_{max}$, or below their minimum stable load, $Q_{min}$, where combustion stability problems prevent electricity production. The minimum stable load for hydro and geothermal plants is approximated as 0. Therefore, constraints on operating limits were only applied to the subset of traditional thermal plants, $t$. The binary variable, $Commit_{tp}$, is used to describe if a thermal plant is connected or disconnected at
any operating period, \( p \). This variable adopts a value of 1 when the unit is connected and zero otherwise. The following formulation was used to describe the maximum and minimum production limits for all thermal generators, accounting for their connection status during each period.

\[
Q_{tp} \leq Commit_{tp} \times Q_{max_t} \quad (5.2)
\]

\[
Q_{tp} \geq Commit_{tp} \times Q_{min_t} \quad (5.3)
\]

**Ramping constraints**

Also known as load gradient constraints, these limit the variations in power output in two consecutive periods. Because hydropower plants can ramp up and down quickly, ramping constraints are only applied to the thermal subset, \( t \), of all generators, \( g \). The purpose of these constraints is to limit the allocation of connected power above the minimum stable load, \( Q_{min_{tp}} \), in each period to the ramping up, \( U_{pt} \), or ramping down, \( Down_{t} \), limitations of each plant.

\[
Q_{tp} - Q_{t(p-1)} \leq U_{pt} \quad (5.4)
\]

\[
Q_{t(p-1)} - Q_{tp} \leq Down_{t} \quad (5.5)
\]
5.1.2 Operating Constraints

Spinning reserve

The spinning reserve constraint was added to ensure reliability conditions were met through thermal or hydro plants. The spinning reserve is formulated as a restraint on the maximum allowable output from committed plants in each period.

\[ SpRes_p = Q_{\text{max}} g \times \text{Commit}_{gp} - Q_{gp} \] (5.6)

Demand balance

Net electricity from thermal, hydro, solar, wind, and unserved power must equal net demand in each period. In UC2012 there is no contribution from wind generators. With variable operating costs effectively zero, solar and wind generation are assumed to have priority dispatch in the system. The current model does not include the possibility to curtail wind and solar generation.

\[ \sum_t Q_{tp} + \sum_h Q_{hp} + \text{Solar}_p + \text{Wind}_p + PNS_p = D_p \] (5.7)

Start ups and shut downs

Two binary variables, \( \text{Startup}_{gp} \) and \( \text{Shutdown}_{gp} \), were created to designate the start up and shut down decisions for plant, \( g \), during period, \( p \). A value of 1 is assigned if a start up or shut down decision is made and zero otherwise. A plant that is already connected in the previous period, \( p - 1 \), can shut down or continue operating during
period $p$ but it cannot start up. Similarly a plant that is off in $p - 1$ can start up or remain off during period $p$ but it cannot shut down again.

$$Commit_{gp} = Commit_{g(p-1)} + Startup_{gp} - Shutdown_{gp} \quad (5.8)$$

**Reservoir rule curves**

Hydropower plant operators provided maximum reservoir volumes as well as monthly rule curves for each reservoir plant to ensure minimum levels of water are maintained. Monthly rule curves for each reservoir were provided by the plant owners and are presented in Appendix A. Equation 5.9 below contains the reservoir constraint used to maintain the reservoir volume, $Res_{rp}$, for each reservoir, $r$, within its operating limits.

$$Res_{minrp} \leq Res_{rp} \leq Res_{maxrp} \quad (5.9)$$

**Reservoir balance**

Equivalent reservoirs were used to represent the available energy in each reservoir during period, $p$. Power generation from reservoir hydropower plants has a non-linear dependence on the water discharge rate and reservoir height. However, modeling this non-linearity was beyond the scope of this study and a constant power output was used for all reservoir heights per volume of water discharged. Kenya’s hydropower plants consist of one run of river plant with no reservoir, one independent reservoir plant, and 5 cascading reservoir plants. For the

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plants in the cascading series, reservoir levels must include water flows from upstream plants as well as its own use and inflow sources. The energy stored in a reservoir, $Res_{rp}$, is calculated as the initial reservoir level from the previous period, $Res_{r(p-1)}$, less production, $Q_{hp}$, and spills, $s_{rp}$, plus associated inflows, $i_{rp}$. In the case of cascading reservoirs, downstream equivalent reservoirs also include upstream turbined water, $Q_{hup,p}$, and upstreamed spilled water, $s_{hup,p}$. The relationship between turbined water and power generation is given by the plant’s production function, a value specific to each hydro plant and provided by the plant owner.

$$Res_{rp} = Res_{r(p-1)} - (Q_{hp} + s_{hp}) + (i_{rp} + \sum_{hup} [Q_{hup,p} + s_{hup,p}]) \quad (5.10)$$

### 5.1.3 Cost of Generation

The costs associated with thermal generation include production cost and start-up cost. The first includes the cost of fuel as well as plant operation and maintenance-related costs.

Input-output curves relate gross power output to fuel consumption (Figure 5-1)[38]. These curves may occasion discontinuities and non-convexities in fuel consumption as the level of power output changes. In the Figure below the y-intercept, $\beta$, represents the fixed fuel consumption that the engine uses each hour. For this model, the following simplifications were introduced to calculate costs associated with thermal generation plants. The relationship between fuel expenditure and
output was assumed to be linear and is represented by the variable $\alpha$. Start up costs depend on initial boiler conditions and can be expressed as an exponential function dependent on the time lapse since the last shut down. For simplicity, start-up costs were represented by a single cost always incurred when a start up decision is made based on the amount of fuel consumed during start up, $\gamma$, times the cost of fuel. For hydro and geothermal power plants, there is no cost associated with fuel consumption.

All plants have variable and fixed operation and maintenance costs and EPPs incur an additional fixed annual leasing cost. Variable operation and maintenance costs, $\omega$, are assumed to depend linearly on the gross output from each plant. The inclusion of leasing and fixed costs are included to account for potential savings from “mothballing” or avoiding the use of a plant altogether with added solar capacity. For existing plants, the variable $fixed_g$ refers to only fixed operation and maintenance costs. New plants in UC2017 also include additional an-
annual fixed costs associated with investment. The binary variable $Fix$ is used to designate if a plant is dispatched during the year, taking on a value of 1 if it is used for at least one hour during the year and zero if it is not used at all.

5.1.4 Formulation of the Objective Function

The objective function (Equation 5.11) can be formulated as the minimization, in all periods, of the sum of: 1. penalties for non-served power, 2. total expected variable costs, and 3. fixed and operation and maintenance costs.

$$\min \sum_{p} \left[ c_{pns} \times PNS_{p} + \sum_{g} \left[ o_{g} Q_{gp} + f_{g} \times (\beta_{g} Commit_{gp} + \gamma_{g} Startup_{gp} + \alpha_{g} Q_{gp}) \right] \right] + \sum_{g} Fix_{g} \times (fixed_{g} + lease_{g})$$

(5.11)

The objective function is subject to the constraints outlined above in Equations 5.2, 5.3, 5.4, 5.5, 5.6, 5.7, 5.8, 5.9, 5.10.

5.2 Input Parameters

This section contains an overview of all input parameters used in UC2012 and UC2017 (Table 5.1). As a matter of nomenclature in GAMS, input values provided by the user are referred to as parameters and decision variables with values determined by the optimization algorithm are re-
ferred to as variables. Each input parameter is preceded by the letter $p$ to designate it as an input and not a decision variable.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$pD$</td>
<td>Demand in each period [GW]</td>
</tr>
<tr>
<td>$pSpRes$</td>
<td>Spinning reserve in each period [GW]</td>
</tr>
<tr>
<td>$pCNSE$</td>
<td>Cost of non-served energy [$$/GWh]</td>
</tr>
<tr>
<td>$pQ_{max}$</td>
<td>Maximum output [GW]</td>
</tr>
<tr>
<td>$pQ_{min}$</td>
<td>Minimum output [GW]</td>
</tr>
<tr>
<td>$pOut$</td>
<td>Outage rate [p.u.]</td>
</tr>
<tr>
<td>$pk$</td>
<td>Auxiliary load factor [p.u.]</td>
</tr>
<tr>
<td>$pO$</td>
<td>Variable O &amp; M cost [$$/GWh]</td>
</tr>
<tr>
<td>$pFixed$</td>
<td>Annual fixed cost [$M$/GW]</td>
</tr>
<tr>
<td>$pLease$</td>
<td>Leasing cost of EPP [$M$/GW]</td>
</tr>
<tr>
<td>$pUp$</td>
<td>Upward ramping rate [GW/h]</td>
</tr>
<tr>
<td>$pDown$</td>
<td>Downward ramping rate [GW/h]</td>
</tr>
<tr>
<td>$pF$</td>
<td>Fuel Cost [$$/Mth]</td>
</tr>
<tr>
<td>$pAlpha$</td>
<td>Variable fuel consumption [Mth/GWh]</td>
</tr>
<tr>
<td>$pBeta$</td>
<td>Fixed fuel consumption [Mth/h]</td>
</tr>
<tr>
<td>$pGamma$</td>
<td>Fuel consumption during start up [Mth]</td>
</tr>
<tr>
<td>$pRes_{max}$</td>
<td>Maximum reservoir volume [$Mm^3$]</td>
</tr>
<tr>
<td>$pRes_{min}$</td>
<td>Minimum reservoir volume [$Mm^3$]</td>
</tr>
<tr>
<td>$pInflow$</td>
<td>Inflow into reservoir [$Mm^3$]</td>
</tr>
<tr>
<td>$pProdFunc$</td>
<td>Production function of hydro plant [GWh/$Mm^3$]</td>
</tr>
<tr>
<td>$pInsol$</td>
<td>Global horizontal insolation [p.u.]</td>
</tr>
<tr>
<td>$pPVplant$</td>
<td>Capacity of solar PV plant [GW]</td>
</tr>
<tr>
<td>$pWind$</td>
<td>Wind production [GWh]</td>
</tr>
</tbody>
</table>

Table 5.1: Input parameters for UC2012 and UC2017
(Mth is an energy unit. 1 thermie (th) = 4.1868 MJ)

5.2.1 Demand

UC2012

Hourly values for demand in UC2012 were based on actual loads experienced during the period of July 2011 - June 2012 provided by the system operator [48]. Kenya experiences a fairly stable load during the year (Figure 5-2) with minimal season variation.
The daily peak load occurs in the evenings with a peak load averaging between 1000 and 1200 MW. The system experiences high transmission and distribution losses averaging 14.5%, meaning the system will actually need to generate 1374 MW of power to meet a demand of 1200 MW. The majority of these losses, over 12%, occur at the distribution level [55]. While rooftop solar PV installations may avoid distribution losses, larger installations being considered in this study will most likely still use the distribution system and contribute to these losses. This factor was included in the model by increasing all load values provided by the system operator by 14.5%.

**UC2017**

Predicting future demand is challenging, especially in a region with existing suppressed demand. The Government of Kenya used end-use electricity models to forecast peak demand to 2031 [55]. Based on these forecasts, the peak demand in 2017 will be 3,230 MW, an increase of over 2.5 times the 2012 peak demand. Hourly load curves for 2017 were
created by increasing each 2012 value by a linear multiple equal to the ratio of 2017 and 2012 peak demands. There are two shortcomings of this approach. First, as with any demand forecast, demand may not grow as expected, resulting in over- or under-estimates of peak demand. Second, this approach does not account for future shifts in consumption patterns. As more Kenyans gain access to electricity, greater demand from residential consumers may change the shape of the daily demand profile.

Targeted network loss levels have not been made available past 2014. Based on loss data covering the period 2007 - 2012, reductions in losses average 0.5% per year and are expected to continue at this rate until 2014 [55]. This rate of reduction was used to predict losses in 2017 would decrease 2.5% from 2012 levels to 12%.

5.2.2 Spinning Reserve

The national grid code sets a reserve capacity requirement that ensures adequate generation to meet demand if the two largest units of the system are unavailable [29]. This requirement includes both reactive and active energy capacity and it is not clear what portion of this requirement is specifically for spinning reserves. Additionally, we did not have adequate data on the size of individual units for each plant to determine the two largest. For these reasons, the spinning reserve requirement, $vSpRes$, was simplified to equal the capacity of the largest dispatched plant in each period.
5.2.3 Cost of Non-Served Energy

The Kenyan Government estimates the cost of non-served energy to be $0.84/kWh [55]. The value was used in both UC2012 and UC2017. The value of non-served energy in 2017 is likely to be higher than the current value as economic development will tend to increase the negative impact of supply interruptions.

5.2.4 Maximum and Minimum Operating Capacities

The following table contains the power plants included in UC2012 and UC2017 as well as their maximum and minimum installed capacities.

In both the UC2012 and UC2017 models, 75.9 MW of small hydropower plants and 2.5 MW of geothermal capacity in UC2012 were not included in the model due to insufficient data. Planned geothermal, medium speed diesel, and coal plants in UC2017 are represented as the aggregate of their capacities.

In order to assess if added solar generation could influence the construction of future plants, the total installed capacities of coal and medium speed diesel (MSD) plants are used as decision variables in UC2017 to determine the optimal amount of each technology under different scenarios of installed solar capacity.
<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Type</th>
<th>Fuel</th>
<th>2012</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Qmax (MW)</td>
<td>Qmin (MW)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Qmax (MW)</td>
<td>Qmin (MW)</td>
</tr>
<tr>
<td>Kamburu Hydro</td>
<td>Hydro</td>
<td>Reservoir</td>
<td>94.2</td>
<td>94.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>225.0</td>
<td>225.0</td>
</tr>
<tr>
<td>Gitaru Hydro</td>
<td>Hydro</td>
<td>Reservoir</td>
<td>44.0</td>
<td>76.0</td>
</tr>
<tr>
<td>Kindaruma Hydro</td>
<td>Hydro</td>
<td>Reservoir</td>
<td>40.0</td>
<td>40.0</td>
</tr>
<tr>
<td>Masinga Hydro</td>
<td>Hydro</td>
<td>Reservoir</td>
<td>164.0</td>
<td>164.0</td>
</tr>
<tr>
<td>Kiambere Hydro</td>
<td>Hydro</td>
<td>Reservoir</td>
<td>106.0</td>
<td>106.0</td>
</tr>
<tr>
<td>Turkwel Hydro</td>
<td>Hydro</td>
<td>RoR1</td>
<td>60.0</td>
<td>60.0</td>
</tr>
<tr>
<td>Sondu Hydro</td>
<td>Hydro</td>
<td></td>
<td>733.2</td>
<td>765.2</td>
</tr>
<tr>
<td>Olkaria I Geother</td>
<td>Geothermal</td>
<td></td>
<td>45.0</td>
<td>45.0</td>
</tr>
<tr>
<td>Olkaria II Geother</td>
<td>Geothermal</td>
<td></td>
<td>105.0</td>
<td>105.0</td>
</tr>
<tr>
<td>OrPower4 Geother</td>
<td>Geothermal</td>
<td></td>
<td>52.0</td>
<td>52.0</td>
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<td>GEO Geother</td>
<td>Geothermal</td>
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<td>858.3</td>
<td></td>
</tr>
<tr>
<td>Total Hydro</td>
<td></td>
<td></td>
<td>202.0</td>
<td>1060.3</td>
</tr>
<tr>
<td>Kipevu I Diesel</td>
<td>HFO1</td>
<td>75.0</td>
<td>37.5</td>
<td>75.0</td>
</tr>
<tr>
<td>Kipevu II Diesel</td>
<td>HFO</td>
<td>115.0</td>
<td>57.5</td>
<td>115.0</td>
</tr>
<tr>
<td>KipevuGT Gas Turbine</td>
<td>Kerosene</td>
<td>60.0</td>
<td>13.4</td>
<td></td>
</tr>
<tr>
<td>Iberafrica1 Diesel</td>
<td>HFO</td>
<td>56.0</td>
<td>28.0</td>
<td>65.0</td>
</tr>
<tr>
<td>Iberafrica2 Diesel</td>
<td>HFO</td>
<td>52.5</td>
<td>26.5</td>
<td>52.5</td>
</tr>
<tr>
<td>Tsavo Diesel</td>
<td>HFO</td>
<td>74.0</td>
<td>27.0</td>
<td>74.0</td>
</tr>
<tr>
<td>Rabai Diesel</td>
<td>HFO</td>
<td>83.3</td>
<td>45.0</td>
<td>83.3</td>
</tr>
<tr>
<td>EPP2 Diesel</td>
<td>HFO</td>
<td>120.0</td>
<td>60.0</td>
<td></td>
</tr>
<tr>
<td>MSD Diesel</td>
<td>HFO</td>
<td>-</td>
<td>332.0</td>
<td>166.0</td>
</tr>
<tr>
<td>COAL Coal</td>
<td>HFO</td>
<td>-</td>
<td>600</td>
<td>360</td>
</tr>
<tr>
<td>Total Conventional Thermal</td>
<td></td>
<td>635.8</td>
<td>304.7</td>
<td>1387.8</td>
</tr>
<tr>
<td>Mumias Cogeneration Bagasse</td>
<td></td>
<td>26.0</td>
<td>6.5</td>
<td>26.0</td>
</tr>
<tr>
<td>Ngong Wind</td>
<td>-</td>
<td>25.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acclus Wind</td>
<td>-</td>
<td>60.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LTWPP Wind</td>
<td>-</td>
<td>300.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Osiwo Wind</td>
<td>-</td>
<td>50.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Other</td>
<td></td>
<td>26.0</td>
<td>6.5</td>
<td>461.5</td>
</tr>
<tr>
<td>Total Capacity</td>
<td></td>
<td>1597</td>
<td>311.2</td>
<td>3674.8</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>763.8</td>
<td></td>
</tr>
</tbody>
</table>

Table 5.2: Generating units included in UC2012 and UC2017

1 RoR refers to run-of-river and HFO refers to heavy fuel oil.
2 Leased capacity from an emergency power provider.

### 5.2.5 Cost and Operating Parameters

Table 5.3 contains the operating and variable cost parameters for each generation type.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Heavy Fuel Oil</th>
<th>Kerosene GT</th>
<th>Geothermal</th>
<th>Cogeneration</th>
<th>Hydro</th>
<th>Coal</th>
</tr>
</thead>
<tbody>
<tr>
<td>pOut</td>
<td>0.902</td>
<td>0.922</td>
<td>0.932</td>
<td>1</td>
<td>0.903</td>
<td>.733</td>
</tr>
<tr>
<td>pk</td>
<td>0.94</td>
<td>0.94</td>
<td>1</td>
<td>0.98</td>
<td>1</td>
<td>0.9</td>
</tr>
<tr>
<td>pO</td>
<td>9</td>
<td>12</td>
<td>5.57</td>
<td>9</td>
<td>5.3</td>
<td>4.3</td>
</tr>
<tr>
<td>p Lease</td>
<td>40.8</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>p Up</td>
<td>0.12</td>
<td>0.12</td>
<td>0.005</td>
<td>0.13</td>
<td>-</td>
<td>0.6</td>
</tr>
<tr>
<td>p Down</td>
<td>0.12</td>
<td>0.12</td>
<td>0.005</td>
<td>0.13</td>
<td>-</td>
<td>0.6</td>
</tr>
<tr>
<td>p Alpha</td>
<td>1.83</td>
<td>2.74</td>
<td>0.001</td>
<td>9.99</td>
<td>-</td>
<td>2.37</td>
</tr>
<tr>
<td>p Beta</td>
<td>0.002</td>
<td>0.001</td>
<td>0.001</td>
<td>0.01</td>
<td>-</td>
<td>0.002</td>
</tr>
<tr>
<td>p Gamma</td>
<td>0.02</td>
<td>0.02</td>
<td>0.001</td>
<td>0.01</td>
<td>-</td>
<td>0.004</td>
</tr>
</tbody>
</table>

Table 5.3: Operating parameters for included generators
[55, 64, 58, 50, 72, 31]

Information on the cogeneration plant was not available from the plant owner or system operator. The assumption of 100% availability, while very conservative, should not dramatically affect unit commitment decisions due to the plant’s small contribution to the overall system. Cogeneration values were based on the available data for a bagasse plant with a heat rate of 10,000 kcal/kWh, burn rate of 300 t/h and start up and shut down times of 2 hours. The energy density of bagasse was taken to be 3,000 kcal/ton.

There are seven heavy fuel oil and two kerosene-fueled gas turbine plants currently operating in Kenya. Based on available data, I confirmed that Wärtsilä 18V46 engines are used in 5 of the heavy fuel oil plants while the kerosene gas turbines use General Electric PG6541B engines [47]. Manufacturer’s data on fuel consumption during start up and shut down and ramping rates were not available for the PG6541B engine. In this case, values for the 18V46 engines were used. Operating parameters for new diesel capacity in UC2017 were based on the Wärtsilä 18V46 engine.
Even though geothermal plants do not consume fuel like diesel or kerosene plants, nonzero fuel consumption values were used to allow GAMS to complete the optimization problem. Parameters for coal plants in UC2017 were based on values obtained for coal plants in the ERCOT system in the United States.

This analysis assumes that no major changes in operational parameters such as fuel consumption and outage rates will occur between 2012 and 2017. However, there will be differences in the fixed costs associated with new and existing plants as well as fuel prices over the 5 year study period. Existing plants only incur a fixed operation and maintenance cost while fixed costs for new plants included in UC2017 will also include investment costs. Tables 5.4 and reftab:fcost2017 contains the fuel and fixed costs associated with each technology in UC2012 and UC2017 respectively. Note that the values for pFixed in UC2017 include both fixed operation and maintenance costs and fixed investment costs for new plants while existing plants in UC2012 only include the former.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>HFO</th>
<th>Kerosene GT</th>
<th>Geothermal</th>
<th>Cogen</th>
<th>Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>pFixed</td>
<td>62.5</td>
<td>11.8</td>
<td>56</td>
<td>118</td>
<td>213</td>
</tr>
<tr>
<td>pF</td>
<td>70.66</td>
<td>81.09</td>
<td>0.001</td>
<td>22.1</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 5.4: Fuel and fixed costs for included generators in UC2012
[55, 72, 9, 10]
### Table 5.5: Fuel and fixed costs for included generators in UC2017

<table>
<thead>
<tr>
<th>Parameter</th>
<th>HFO</th>
<th>Geothermal</th>
<th>Cogen</th>
<th>Hydro</th>
<th>Coal</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>pFixed</td>
<td>239</td>
<td>517</td>
<td>118</td>
<td>213</td>
<td>429</td>
<td>317</td>
</tr>
<tr>
<td>pF</td>
<td>61.23</td>
<td>0.001</td>
<td>22.1</td>
<td>-</td>
<td>14.28</td>
<td>-</td>
</tr>
</tbody>
</table>

5.2.6 Hydro Inflows and Reservoir Management

The seven hydropower plants included in UC2012 and UC2017 consist of one run-of-river plant along the Sondu River, one reservoir plant along the Turkwel River, and 5 cascading reservoir plants along the Tana River. The relationship of plants along the Tana cascade and sources of inflows are shown in Figure 5-3.

![Figure 5-3: Schematic of Tana cascade](image)

Variations in annual inflows can have a dramatic effect on unit commitment and historic data have demonstrated large fluctuations in annual inflows. Historic inflow data ranging from 1948-1994 were provided by the plant owner (Appendix B). In order to capture the variations in annual inflows over this period and the effects of any inter-annual relationships (i.e. a dry year followed by a dry year) while keeping the model deterministic, UC2012 and UC2017 were run using each of
the 47 annual sets of data in sequence. The solution obtained for each simulated year was averaged to represent an *average* hydrological year. A cumulative density function of the historic inflows was used to characterize *dry* and *wet* hydrological years. Solutions from years in the lowest and highest 20th percentile of total annual inflows were averaged to estimate a typical dry and wet year, respectively (Figure 5-4).

![Figure 5-4: Classification of dry and wet hydrological years](image)

Table 5.6 contains the production function values for each hydro plant.

<table>
<thead>
<tr>
<th>Plant</th>
<th>pProdFunc</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turkwel</td>
<td>0.826</td>
</tr>
<tr>
<td>Masinga</td>
<td>0.0869</td>
</tr>
<tr>
<td>Kamburu</td>
<td>0.2</td>
</tr>
<tr>
<td>Gitaru</td>
<td>0.3</td>
</tr>
<tr>
<td>Kindaruma</td>
<td>0.081</td>
</tr>
<tr>
<td>Kiambere</td>
<td>0.324</td>
</tr>
<tr>
<td>Sondu</td>
<td>0.54</td>
</tr>
</tbody>
</table>

Table 5.6: Production function for hydro plants

\[GW h/M m^3\] [52]
5.2.7 Solar Generation

As discussed in 3.2, hourly ground based measurements averaged over 23 locations and a period of 3 years were used to estimate the expected hourly incoming solar insolation. The solar constant, a measure of incoming radiation on a perpendicular surface over a given area, is approximately 1366 W per m\(^2\). As light passes through the atmosphere the sun’s rays are absorbed and scattered, leaving the actual surface value to be around 1000 W per m\(^2\). This value is taken to be the ‘peak sun’ or rated peak insolation for which most PV panels are calibrated [71]. In order to convert the averaged hourly measured radiation values to generated energy the average radiation was divided by the ‘peak sun’ to attain an insolation factor, \(p_{\text{Insol}}\). The parameter \(p_{\text{PVplant}}\) was used to designate the size of the solar plant. Averaged hourly generation was found by multiplying the \(p_{\text{PVplant}}\) by the insolation factor, \(p_{\text{Insol}}\).

5.2.8 Wind Generation

The projected power system in 2017 includes a significant increase in wind generation from four proposed plants. Hourly output from wind plants is generally calculated using a power curve, specific to each turbine, to convert wind speed to power generation. Unfortunately, hourly time series data were not available for the proposed wind sites and this method could not be used. Instead, annual production estimates found in project design documents for each plant were used to estimate hourly
generation. Though wind generation experiences significant daily and seasonal fluctuations, wind output in UC2017 was assumed to be constant in every hour. Table 5.7 contains the expected wind generation from each proposed plant.

<table>
<thead>
<tr>
<th>Plant</th>
<th>Annual Generation (GWh)</th>
<th>Hourly Generation (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ngong</td>
<td>71.2</td>
<td>8.13</td>
</tr>
<tr>
<td>Aeolus</td>
<td>180</td>
<td>20.55</td>
</tr>
<tr>
<td>LTWPP</td>
<td>1,440</td>
<td>164.4</td>
</tr>
<tr>
<td>Osiwo</td>
<td>146</td>
<td>16.7</td>
</tr>
</tbody>
</table>

Table 5.7: Estimated wind generation [35, 74, 79]

As interest in wind generation in Kenya grows, additional wind resource data may become available allowing for more greater accuracy in future studies.

### 5.3 Model Validation

The model validation was performed by comparing simulated output with actual historic inflow data with recorded generation data during the same period. The plot below (Figure 5-5) contains the results of this analysis for each hydropower plant. The numbers below each plant name correspond to the number of years of historic data that were available for comparison. Comparisons for all plants along the Tana cascade covered 21 years of historic inflow and generation data. The Turkwel and Sondu plants had 20 and 3 years of available comparison data, respectively.
Overall, the simulated values correspond to historic generation output. However, in the cases of Kamburu, Kindaruma, and Kiambere discrepancies ranging from 10-20% difference exist. These could be the result of changing operational rule curves to match hydrological conditions at the time, plant outages, or some other event that is not included in historic generation data and could not be included in the model.

Figure 5-5: Model validation comparing simulated and historic generation from hydro power plants

5.4 Limitations of the Model

As with any model, it is important to note that this model cannot accurately predict all behaviors of a complex system such as a national electric power system. Instead, it is meant to provide insight into how different elements in the system will interact and provide guidance on what factors play an important role in changing these outcomes. In this attempt to represent Kenya’s electric power system at an aggre-
gate level, several simplifications have been identified regarding the generating characteristics of certain plants, plant availability, demand, and solar resource. In addition to these simplifications, it is important to note that expansion and operating decisions are made under an implicit assumption that future hydrological, solar, and wind conditions over the entire operating period are known in this model. In an actual system, the system operator must make dispatch decisions in the face of uncertainty regarding these resources resulting in different operational outcomes. Despite these simplifications, the results of this model should prove useful to test the feasibility of solar PV in Kenya and provide key insights to policy-makers on what economic, technical, or policy factors may effect this outcome.
Chapter 6

Presentation and Discussion of Results

The previous section outlined the methodology, model design, and input parameters used in the UC2012 and UC2017 models of Kenya’s generation system. The models were solved as mixed integer linear problems using the CPLEX interior point method in GAMS [30]. For each model, eleven scenarios were run: one base case with no solar, referred to as the business-as-usual (BAU) case, and ten solar scenarios with installed PV capacity ranging from 100 - 1000 MW in increments of 100. The code used for UC2012 and UC2017 can be found in Appendices C and D, respectively. This chapter highlights key results from select scenarios. The results for all tested scenarios can be found in Appendix E.

The output from each scenario includes the hourly scheduling of each plant and total annual costs. UC2017 also includes the optimal size of installed coal and medium-speed diesel plants as an output. From these
results, the economic viability of adding solar to the Kenyan generation system was evaluated based on the effects on system operations and total annual costs. In addition, these results were used to identify a range of possible solar investment sizes that could be feasibly added in each year studied.

A primary concern of adding a new technology into an existing power system is whether it can be integrated into the system without violating the operating constraints of existing plants. As previously mentioned, solar generation is generally treated to have zero variable cost and is assumed to be dispatched first over other technologies in the system in a lowest-cost dispatch regime. This may result in potential operational problems if existing plants cannot adjust their output due to technical limitations such as minimum load requirements or ramping rates to compensate for solar generation, resulting in unserved loads or overproduction. For each scenario, the hourly scheduling of each plant was used to evaluate the operational impacts of added solar. The study shows that the flexibility of existing generators - particularly reservoir hydro plants - can enable large capacities of solar PV to be integrated into the system.

Another concern for system planners is the cost of adding a new technology to the system. This includes the investment and variable costs of the added plant itself but also the potential costs imposed on other plants. For example, intermittent renewables may result in additional operating costs for other plants that must ramp up and down.
more frequently to accommodate changes in output from the intermittent source. For this analysis, the total system cost was calculated as the hourly variable cost of all generators plus their annual fixed costs. The value of added solar generation to the system is the reduction in total system cost in each solar scenario from the BAU case. These savings reflect the maximum amount the centralized power system planner could pay a solar plant owner for generated power without increasing system costs over the BAU case. Comparing these maximum rates, expressed either as a payment per kWh generated or per MW installed, to prices proposed in Kenya and in similar international markets can provide a top-level assessment of the economic feasibility of building a solar plant in Kenya.

Finally, it is important to consider the sensitivity of these results to changes in demand, solar price, hydrological conditions, and fuel price. These analyses can reveal the range of solar PV penetrations, if any, for which solar PV investment is both technically and economically feasible for the 2012 and 2017 systems. The following sections contain the results of these analyses for UC2012 and UC2017.

6.1 UC 2012

6.1.1 Operations

The 2012 system is composed of hydropower, fuel oil, geothermal, and bagasse plants. Figure 6-1 shows the generation profile of a sample
week in the BAU scenario. As shown below, the majority of demand is met through hydropower and fuel oil plants. A key result to note is the incidence of unmet demand during peak hours on some days. These periods are represented as “power non-served” (PNS) in black. With a total installed capacity of 1,597 MW and peak demand of 1,228 MW in 2012 it may seem that the system should be capable of meeting demand in all periods. However, as discussed in 5.2.5, the maximum capacity of each plant was reduced to account for plant outages and the system’s own use, reducing the total effective capacity to 1,323 MW. Additionally, the inclusion of network losses as additional demand increased the peak demand to 1,406 MW. As a result, for a small number of hours, about 250, there is insufficient capacity to meet demand. This is consistent with the 238 load shedding events recorded during the same period and discussed in 2.2.2.

Figure 6-1: BAU weekly generation profile in UC2012
As solar capacity is added to the system, the model optimizes to reduce total production from the most expensive plants and minimize additional ramping and start up costs. Production during the day from fuel oil plants is reduced first due to their high variable costs. At the point at which further reductions in output would require the plant to shut down completely, the model optimizes to reduce the output of reservoir hydropower plants that can alter their output without a cost penalty and avoid additional startup costs of fuel oil plants. At high levels of solar penetration, fuel oil plants are shut down during the day and geothermal and bagasse plants’ outputs are also reduced. Figure 6-2 shows the effect of 500 MW of added solar capacity to the weekly generation profile for the same week in Figure 6-1.

![Weekly Generation Profile: June 500 MW Average Scenario](image)

Figure 6-2: Weekly generation profile in UC2012 with 500 MW solar PV

For reservoir hydropower plants, reduced daytime generation allows these plants to shift their generation to evening hours reducing the
instances of unmet demand. Figure 6-3 shows the total annual unmet load in each solar scenario. The addition of solar PV reduces the annual unmet load compared with the BAU case, particularly during dry years, but these gains level off after 400 MW when shifted hydro production permits all hydropower plants to operate at full capacity during the evenings. However, since generation from solar does not coincide with peak demand solar PV cannot directly resolve the capacity shortages that occur during evening peaks.

![Impact of Solar PV on Annual Power Non-Served](image)

Figure 6-3: Total annual power non-served in UC2012 for each solar and hydrological scenario.

Another result of shifted hydropower production is reduced fuel oil production during the evenings. Thus generation from fuel oil plants is displaced during the day by solar generation and during the evening by increased hydro generation. A question posed by this thesis was whether high levels of solar power would “mothball” existing power plants or alleviate the need for leased capacity from emergency power producers. These results show that added solar can reduce the annual
generation from fuel oil plants (Figure 6-4), but it cannot alleviate the need for these plants altogether because they are used to meet peak demand during the evening. For example, in the BAU scenario one kerosene gas turbine plant is committed over 4,900 hours. In the 100 MW scenario, this is reduced to only 634 hours. However, by 400 MW the total committed hours reach a minimum of 490 and higher levels of installed solar PV have no effect on the number of hours dispatched and only a small effect on the total generation from the plant. Instead, the number of production hours from the next most expensive plant is reduced. Figure 6-4 contains the comparison of total annual generation output for each scenario in UC2012.

![Optimal Generation Output under Different Solar Scenarios](image)

**Figure 6-4:** Total annual generation output in UC2012 under different assumed solar scenarios

This analysis has found that very high levels of solar PV can be integrated into the Kenyan system, reducing instances of power shortfalls and total production from fuel oil plants. This outcome is made pos-
sible by changing the operating regime of flexible reservoir hydropower plants.

6.1.2 Economic Analysis

In order to assess the economic feasibility of solar PV in the centrally planned Kenyan system, the reduced cost of annual production was used to determine the maximum value of added solar in each scenario. The reduced cost is the difference in total costs - fixed and variable - in each scenario from the BAU scenario. In UC2012, these savings are largely driven by reduced fuel consumption in fuel oil plants. Since investments that increase overall system costs are undesirable, these savings were taken as the maximum value of added solar to the system in each scenario. The reduced cost was then used to determine the maximum amount a potential solar plant operator could earn for each level of installed solar capacity. This can be represented in two ways: a price paid per unit of energy generated (Figure 6-5) or a price per installed capacity (Figure 6-6).

Two trends emerge from this analysis: the value of solar falls as installed capacity increases and hydrological conditions move from dry to wet. These trends are expected since the model will optimize to displace the most expensive generation technologies with solar generation first, capturing the greatest savings immediately. In the dry scenario, not only is generation from all non-hydro plants higher, but production from the most expensive fuel oil plants is increased to compensate for
reduced hydropower production. Therefore, the reduced cost of solar is able to capture larger savings by displacing these plants.

![Graph showing maximum remuneration to solar generator at constant cost](image)

**Figure 6-5:** Generation payments possible to solar generators (2012)

![Graph showing achievable solar plant investment cost](image)

**Figure 6-6:** Possible investment costs for solar PV plants (2012)

As shown in Figure 6-5 the maximum payments that are economically justified to pay to solar generators fall from over $0.30 to $0.18 per kWh in the dry scenario and over $0.20 to $0.14 per kWh in wet and
average scenarios. For comparison, Kenya’s existing feed-in-tariff (FIT) for grid-connected solar PV, designed to allow private investors to recover their costs plus a reasonable return on investment, is $0.12 per kWh [56]. Even at high levels of solar penetration and wet hydrological conditions economically justified payments to solar generators remain above the FIT. To date, there are no major grid-connected solar PV projects in Kenya and it is yet to be seen if this tariff, recently increased from $0.11 per kWh, will attract new projects. For a comparison with projects being proposed in other developing countries, recent auctions in India and South Africa received bids for solar PV projects for $0.15 and $0.20 per kWh, respectively [39, 60]. Under average hydrological conditions, up to 200 MW could be economically feasible at the bid price seen in South Africa or up to 800 MW at Indian bid price.

When viewed as a maximum investment cost that could be paid to the plant owner (Figure 6-6), values range from over $7.5M to $3.4M per MW in average years. These values were calculated using the expected savings accumulated over the 20-year lifetime of the plant using a discount rate of 5%. For all solar scenarios, these remain above the average cost of private solar PV projects in least developed countries (LDCs) of $3 per W [18].

These initial results suggest that savings from reduced fuel consumption and other variable operating costs could sufficiently compensate solar PV investors at rates comparable to those proposed in Kenya and seen in other developing countries.
6.1.3 Sensitivity Analysis

Changes in demand

A sensitivity analysis was performed to determine the effect of changes in demand on the maximum payments available to solar generators in each scenario. The payments were shown to be highly sensitive to increases in demand and less sensitive to demand decreases (Figure 6-7). This skewed response is due to the highly capacity-constrained nature of the Kenyan system. With no excess capacity, any increase in demand will increase the number of hours that supply is insufficient to meet demand and the generation required from the most expensive units. Therefore added generating capacity from any technology less expensive than fuel oil plants would be highly valuable under these conditions.

By contrast, decreases in demand reduce the generation requirements from the most expensive plants and the total savings available to solar generators. While a decrease in demand would reduce the available compensation, it remains above the Kenyan FIT (dotted red line) for all solar scenarios.

Changes in fuel price

A similar analysis was done to assess the effect of changes in fuel price to the possible payments for solar generation. As shown in Figure 6-8, changes in fuel price had significantly less impact than changes in demand, with a maximum difference of 8% at high levels of solar penetration compared with values of between 17% and 42% difference
in the demand analysis. The limited impact of changes in fuel price is partly due to the large role that hydropower and and geothermal plants - which have no associated fuel costs - play in the 2012 system. Even with reductions in fuel price of up to 10%, the compensation available to solar generators based on the reduced cost remains above the Kenyan FIT for all solar scenarios.

Figure 6-7: Effect of changes in demand on achievable solar payments (2012)

Figure 6-8: Effect of changes in fuel price on achievable solar payments (2012)
Optimal investment level

The previous results demonstrated that investment in solar can reduce total generation costs. At high levels of penetration, solar generation will begin to displace generation from less expensive geothermal and hydropower plants. When this point is reached the total system cost will begin to increase. In order to determine the optimal range of installed solar capacity, the total annual cost of generation was calculated as the fixed and variable cost of existing units plus the variable cost of solar production. I used three possible feed-in-tariff rates for solar based on the experiences discussed above in Kenya, India, and South Africa. For each scenario, the optimal level of solar investment occurs where the total cost curve reaches a minimum. This analysis was done for average, dry, and wet scenarios and the results are presented in Figures 6-9, 6-10, 6-11 and summarized in Table 6.1.

![Total Annual Cost under Different Solar Scenarios](image)

Figure 6-9: Annual generation cost in each solar scenario: Average year (2012)
Figure 6-10: Annual generation cost in each solar scenario: Dry year (2012)

Figure 6-11: Annual generation cost in each solar scenario: Wet year (2012)

<table>
<thead>
<tr>
<th>Cost of Solar $/kWh</th>
<th>Dry Year MW</th>
<th>Average Year MW</th>
<th>Wet Year MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.12</td>
<td>800-900</td>
<td>800-900</td>
<td>800-900</td>
</tr>
<tr>
<td>0.15</td>
<td>500-600</td>
<td>400-500</td>
<td>300-400</td>
</tr>
<tr>
<td>0.20</td>
<td>300-400</td>
<td>100-200</td>
<td>100-200</td>
</tr>
</tbody>
</table>

Table 6.1: Optimal range of installed solar capacities under varying solar price and hydrological conditions (2012)
This analysis presents an idealized case, where all power plants are centrally operated to minimize total system costs and there is no uncertainty regarding the availability of each plant or solar plant output. However, actual system operation involves multiple stakeholders with potentially conflicting objectives. With this in mind, are the proposed operational changes and resulting economic feasibility for solar PV achievable? First, it may prove difficult to convince system operators, plant owners, and the public to reduce output from fuel oil plants already operating in the country to accommodate solar PV production. This is especially true if there are no accompanying increases in total system production or service quality. Additionally, in a system that is not under central planning, existing plants may require some minimum number of committed hours in order to recover their costs and may even have contractual agreements with the power purchaser to this effect. For the most expensive plants, these model results may reduce the number of committed hours below this level. Third, KenGen, the owner of all reservoir hydro plants, must make operating decisions in the face of uncertainty as to available future inflows as well as pressure from the public and GoK - which maintains majority ownership of the company - to maximize hydropower production when water is available. Proposals to shift hydro production during the day while fuel oil plants continue to operate and the reservoirs have sufficient water may meet resistance from the public and politicians. These interests may impact the level of achievable solar penetration in the 2012 system.
6.2 UC 2017

6.2.1 Operations

The projected 2017 generation mix includes significant contributions from geothermal, coal, wind, and imported power. As a result, the role of hydropower and fuel oil plants is diminished compared with the 2012 system. Figure 6-12 contains the generation profile of a sample week in the BAU scenario in UC2017. As in 2012, the model results show that there will continue to be instances of unmet demand in this system as evidenced by the black PNS portions of the curves during some peak hours. The total installed capacity is 4,230 MW with an effective capacity of 3,520 MW after adjustments for outages and net power. The peak demand, projected to be 3,230 MW, was adjusted to 3,840 to account for network losses of 12%.

As solar is added to the system, daytime production from fuel oil
plants is reduced first followed by reductions in coal, imports, and hydroelectric power production. Figure 6-13 contains the weekly generation profile in the 500 MW scenario.

Figure 6-13: Weekly generation profile in UC2017 with 500 MW solar PV

Similar to UC2012, reservoir hydro plants are able to shift some production to evening peak hours, reducing the total annual production from fuel oil, coal, and imports. The projected demand retains its evening peak, based on the demand profile from 2012. As a result, additional solar capacity cannot contribute to meeting peak demand during these periods and instances of unmet demand persist. However, as shown in Figure 6-14 hydro production in UC2017 is already maximized during peak periods and the addition of solar PV - even during the few overlapping hours when demand is increasing and solar plants are generating power - has no significant impact on these values.
Figure 6-14: Total annual power non-served in UC2017 for each solar and hydrological scenario

Figure 6-15 contains the comparison of the annual generation output for each scenario in UC2017. Fuel oil production for non-peak hours is minimized at low levels of solar penetration. The integration of higher levels of solar penetration require reductions in coal and imported power.

Figure 6-15: Total annual generation output in UC2017 under different assumed solar scenarios
In order to evaluate if solar PV would alter the optimal 2017 generation mix proposed in national expansion plans, UC2017 also optimized the level of new coal and medium-speed diesel (MSD) capacities that should be built in each solar scenario. These values were allowed to vary between 0 MW and the proposed sizes in the latest expansion plans. Similar to the leased emergency power in UC2012, the addition of solar PV capacity did not reduce the total capacity required from these plants and the model output of optimal investment size remained the same for all solar scenarios as the BAU case. If the shape of the future demand curve changes such that peak demand corresponds with solar production then added solar capacity may be able to reduce the need for these plants.

This analysis shows that the 2017 system has a smaller dependence on expensive fuel oil plants. As a result, at high levels of PV penetration possible reductions from fuel oil have been maximized and production from imports and coal are reduced. There is no discernible improvement in instances of unmet demand and additional solar capacity is not able to alleviate the need for new coal or MSD plants.

6.2.2 Economic Analysis

A reduced cost analysis of the UC2017 result was used to calculate the maximum value of added solar in each scenario. These results, (Figures 6-16, 6-17), show that the value of added solar falls as the installed capacity increases and solar production begins to displace production
from less expensive plants. The large variations between dry and average or wet years seen in UC2012 is diminished due to smaller contribution from hydro plants to the total system production in UC2017.

Figure 6-16: Generation payments possible to solar generators (2017)

Figure 6-17: Investment cost of solar plants in each scenario (2017)

Figure 6-16 shows the range of maximum payments to solar generators falls from $0.11 per kWh in the 100 MW scenario to $0.08 per kWh in the 1,000 MW scenario. These values are less than those found in
UC2012 which ranged from $0.30-$0.14 per kWh. This indicates that the reduced annual costs from added solar capacity are less in 2017 than the existing system. This is due to the changes in composition of the generation mix between 2012 and 2017. The 2017 system contains increased use of low variable cost technologies such as geothermal, coal, wind, and imports. At the same time, total generation from fuel oil plants is reduced and the most expensive of this type, kerosene gas turbines, are not present in the 2017 system. These results indicate that savings from added solar capacity would not be sufficient to compensate the cost of solar generation at rates above $0.11 per kWh. Any payment rate above this level would increase the total system cost.

The maximum investment cost available to the plant owner (Figure 6-17) ranges from over $2.7M to $1.9M per MW in each scenario. Similarly, these values all fall below the average cost of private solar PV projects in LDCs.

This economic analysis suggests that the changes in composition of the generation mix between 2012 and 2017 reduce the competitiveness of high penetrations of solar PV in the future system. The extensive plans for increased geothermal, coal, and imported power will displace most of the expensive fuel oil production, reducing the potential economic value of solar PV under current prices. However, as discussed in 3.1.4, solar PV prices have fallen dramatically in the last 10 years and it is seems likely that plant prices may fall below current levels, increasing the economic competitiveness of solar in Kenya.
6.2.3 Sensitivity Analysis

Changes in demand

A sensitivity analysis of projected demand was conducted to evaluate the effect on maximum payments available to solar generators (Figure 6-18) as well as the optimal level of new coal and MSD capacity (Figure 6-19). This analysis reveals that solar PV could be economically feasible under the current FIT if demand increases at least 5% above projected levels. However, the current 2017 scenario assumes demand growth of almost 20% annually since 2012. Given historic growth rates between 5-10%, it seems unlikely that demand will increase above the predicted levels. Decreases in demand result in reduced use of fuel oil plants in the BAU scenario, decreasing the value of added solar PV in the system.

Figure 6-18: Effects of demand changes on achievable solar payments (2017)
Decreased demand was found to impact the optimal level of MSD capacity that should be built in the 2017 system. Reductions of 5% projected demand reduce the required MSD plant size to 220 MW from the planned 332 MW in the BAU scenario. If future demand is 10% less than expected, this falls to less than 50 MW. The addition of solar PV has very limited impact on the optimal level of MSD capacity. Optimal investment in coal capacity remained unchanged for all demand scenarios.

Changes in fuel price
An assessment of the effect of changes in fuel price on remuneration for solar generators reveals that solar PV becomes economically feasible only at low capacities and high fuel prices. As Figure 6-20 indicates, a 10% increase in fuel prices above projected levels would make solar PV investments competitive up to 200 MW. Changes in fuel price had
no effect on coal or MSD investments.

![Generation Payment Sensitivity to Changes in Fuel Price](image)

Figure 6-20: Effects of fuel price changes on achievable solar payments (2017)

**Optimal investment level**

The economic analysis found that the reduced cost from added solar PV is only sufficient to remunerate solar generators at a maximum rate of $0.11 per kWh for 100 MW installations, falling to $0.08 per kWh at higher penetration levels. Therefore, using the current prices of $0.12, $0.15, and $0.20 per kWh, the total system cost is expected to increase for all solar scenarios (Figures 6-21, 6-22, 6-23) as a result of solar generation displacing other technologies with lower per unit costs. Therefore, under current assumptions about future prices, demand, and capacity investments solar PV is not an economic investment in the 2017 system.
As previously mentioned, attempts to predict what a future electricity market may look like are challenging. This is particularly true in a developing country like Kenya where the sector is undergoing rapid expansion as well as changes in the regulatory and ownership structure.
Figure 6-23: Annual generation cost in each solar scenario: Wet year (2017)

The effects of variations in demand, fuel price, and the price of solar on the UC2017 results are discussed above. In addition to these uncertainties, there is the potential that new power plants will not be completed as scheduled. Kenya’s capacity expansion plans are ambitious, more than doubling existing capacity by 2017. System planners estimate the new power plants will require an investment of over $3.9 billion. The lengthy processes involved to negotiate contracts with project developers, find adequate financing, and build supporting infrastructure such as transmission lines and ports, may delay some projects from coming on-line in 2017 as planned. If this is the case, Kenya’s dependence on expensive fuel oil production will continue.

Additionally, the reduced cost calculation does not include the significant investments in new support infrastructure required for many of the new plants in the 2017 system. For example, between 2012 and
2015, investments in committed and new transmission infrastructure to provide over 5,500 km of new lines is expected to reach $3 billion [55]. Over one third of this amount is allocated for three key project areas: a 600 km interconnect with Ethiopia ($683M), a 428 km connection to the Lake Turkana Wind Power Project ($195M), and a 750 km line from coal plants located at the coast to Nairobi ($285M).

The significant time and financial commitments required to bring these projects to completion have two implications for solar PV. First, continued use of fuel oil plants that may result if these projects are delayed will extend the timeframe in which solar PV is economically feasible. Second, solar PV can be built in smaller, modular installments connected directly at the distribution level near major load centers. As such it may be favorable to the proposed projects if their large size and infrastructure requirements serve as a roadblock to their completion.

The following chapter will provide a summary of key findings from the study and a discussion of policy recommendations for decision-makers in Kenya as well as other developing countries.
Chapter 7

Discussion and Conclusions

The previous chapter presented the results from the UC2012 and UC2017 models. This chapter offers a summary of key findings and recommendations for energy policy-makers in Kenya and similar developing energy markets in other countries.

7.1 Key Findings

Operational Analysis

- Kenya’s large reservoir hydro power capacity enables the integration of high penetrations of solar PV into the 2012 and 2017 systems without the need for additional investment in storage.

- Added solar production displaces output from the most expensive diesel thermal plants directly during the daytime hours and indirectly through shifted hydro production in the evenings.

- In the 2012 system, solar investments of up to 400 MW can reduce
instances of load shedding by enabling partial shifting of hydro
generation to evening hours. Solar has no similar impact on load
shedding in the 2017 system because evening hydro generation is
already maximized to meet increased demand.

• Diesel capacity, in the form of leased plants in 2012 and new in-
vestments in 2017, is required in both systems to meet evening
peak demand irrespective of PV additions at any penetration level.
Changes in consumption patterns over time that result in a flatten-
ing of the demand curve or daytime peaks in demand (for example,
a relative increase in daytime commercial or industrial activity)
would tend to favor the economics of solar PV over diesel in the
future.

• Achievable changes to operating policies may be limited by pres-
sure from the public to utilize hydro resources when they are read-
ily available and the potential need to meet minimum revenue re-
quirements for existing plants to recover their fixed costs.

Economic Analysis

• Solar PV at current prices is economically competitive in the 2012
system due to the comparatively high cost of operating fuel oil
plants which provide 38% of Kenya’s electricity. Under average hy-
drological conditions and the existing feed-in-tariff of $0.12/kWh,
up to 900 MW of PV (nameplate) capacity could be connected
to the Kenyan grid in 2012 without increasing total system costs.
This feed-in-tariff may reflect overly optimistic project development costs on the part of Kenyan policy-makers. At higher winning wholesale bids recently recorded in South Africa and India ($0.15-0.20/kWh), the economically justified threshold for PV penetration in Kenya ranges from 100-500 MW.

- The existing feed-in-tariff could be increased to attract investment in solar PV plants without increasing total system costs. However, as noted above this would likely result in reducing the level of investment in PV than would be expected under the current feed-in-tariff.

- Current PV capital investment costs remain too high to compete with those of coal, geothermal, hydro, and wind power when compared at the project-level. As a result, investment in solar PV capacity is no longer economically feasible in the 2017 system, where large portions of total power is expected to come from coal, geothermal, hydro, and wind plants.

- The availability of free storage in the form of reservoir hydro capacity enables solar PV to be competitive in the 2012 system. Therefore, in order for solar PV to be economically feasible at even higher penetration levels to meet growing demand, more free storage is required through increased reservoir hydro capacity.

- The cost of required transmission infrastructure for coal, diesel, and wind plants proposed in the 2017 plans is not included in this
analysis. If solar PV could be sited near major load centers, avoiding these transmission investments, the economic competitiveness of solar in the future system would increase.

- In the 2017 system, the most expensive kerosene units have already been decommissioned, removing the economic benefits of displacing generation from these units. Generation from medium-speed diesel plants is the next most expensive and production from these units is concentrated in the evenings to meet peak demand. Therefore, the potential economic gains from displacing production from diesel with solar PV is lost.

7.2 Policy Analysis

7.2.1 Kenyan policy-makers

Our results have a number of implications for key decision-makers within the Kenyan government and major utility companies. Solar PV offers an economic alternative to the current use of fuel oil power, particularly from leased diesel capacity, while at the same time increasing energy security and lowering growth in global CO₂ emissions. In the near term, solar PV is a feasible alternative to increasing diesel production to meet increasing demand because it can be financed and deployed incrementally without accompanying investment in transmission infrastructure. This is particularly important if the large-scale investments required for new geothermal, coal, wind, and imported power fail to at-
tract investors and are therefore delayed, requiring extended use of fuel oil plants. The following are key policy and regulatory considerations for policy-makers keen to promote increased investment in solar PV.

Create an enabling policy environment

There are a number of steps the Government of Kenya can take to encourage greater investment in solar PV projects through national policy initiatives and efforts to encourage greater knowledge sharing and industry development including:

- Develop national solar initiatives with actionable targets linked to a comprehensive capacity expansion plan: The Kenyan government could adopt measure recently used in India and South Africa to achieve low-cost investments in solar PV. These include renewable portfolio standards paired with capacity auctions, tradable renewable energy credits, and obligatory purchase quotas for some or all end-user groups.

- Facilitate greater knowledge sharing: In order to increase awareness about potential projects and accelerate project development, the GoK can sponsor efforts to collect and share ground-based solar resource data in candidate sites. Measures to make available financing for project developers such as partial credit guarantees, interest rate subsidies, exemptions from import tariffs and VAT should be considered. Those measures that are implemented should be widely publicized.
• Create regulatory rules for PV: Policy-makers are currently working with electricity regulators to establish clear procedures and standards to facilitate the uptake of solar water heaters. Similar procedures and standards should be established for solar home systems and solar PV plants along with training programs and public education to build local capacity, increase awareness, and reduce transaction costs.

• Reform the solar PV feed-in-tariff valuation: A feed-in-tariff derived from analysis of the optimal level of PV investment should be developed. The tariff should target displacement of more expensive power sources and be capped at a level that reflects the system's ability to mitigate the associated intermittency.

• Support the domestic solar industry: Kenya has a budding solar power industry with several domestic module manufacturing, project design, and installation companies. Increased public support in the form of funding for research and development and tax exemptions could position Kenya's solar industry to become a regional leader.

Plan with a high penetration of intermittent renewables in mind
High penetrations of intermittent renewables in the Kenyan power system require a high degree of coordination in system operations and planning. Areas of particular importance are as follows:
- Develop reservoir hydro capacity: Solar PV is economically viable in Kenya due to the availability of free storage in the form of reservoir hydro. Therefore, investments in PV should be coordinated with corresponding reservoir hydro capacity to balance potential intermittencies.

- Change the operating regime for reservoir hydro plants: In order to accommodate seasonal and diurnal fluctuations in solar generation, the system operator must manipulate the output from reservoir hydro plants, representing a novel way to operate the system.

- Revise national planning methodologies: Traditional screening curve methodologies used in national planning documents to evaluate candidate technologies do not include system-level cost assessments, penalizing renewable energy technologies. The financial analysis used in the Least Cost Power Development Plan should be updated to include system-level analyses.

- Collaborate with regional neighbors to create regional power pools: Regional power pools can increase overall system flexibility and facilitate higher levels of penetration from intermittent generation sources. Kenya currently has interconnections with Uganda and Tanzania and plans to build a connection with Ethiopia. Coordinated regulatory and infrastructure designs are required to enable regional power trading at a large scale.

Minimize negative environmental impacts
The African continent is expected to be deeply impacted by climate change effects and Kenyans have responded with increased focus on the importance of environmental issues and reductions in carbon emissions as part of their development roadmap [68]. In order to balance the need for new generation capacity with the need to conserve water and land resources, the following actions should be considered:

- Give a high weight to potential environment impacts as part of the site selection process: Proposed projects should include potential impacts of new plants - including hydro, solar, wind, and geothermal - on local populations dependent on waters and lands in the area as part of their cost-benefit analysis.

- Tap into international sources of support for climate change mitigation: International financing schemes designed to reduce global greenhouse gas emissions, such as the Clean Development Mechanism, can offer additional financial support for solar PV projects. For small independent projects, the cost to prepare application documents may be prohibitive without public support.

7.2.2 Implications for other developing countries

Across sub-Saharan Africa, many countries are faced with the same challenges facing the Kenyan system: growing demand for electricity, insufficient generating capacity, long lead times and extensive financial investments required for planned projects to increase generation supply. As a result, many countries have turned to short-term expensive
solutions such as leased emergency power from diesel plants. On the other hand, the characteristics that make solar PV a favorable option in Kenya - an abundant solar resource and large capacities of reservoir hydropower - are also present across sub-Saharan Africa.

In at least 24 of these countries, over 40% of total capacity comes from hydropower, and there is a large untapped hydro potential across the continent. The current total installed hydropower capacity is 27.6 GW but current estimates indicate that there is an additional 171 GW of undeveloped, economically feasible hydropower potential in Africa [1]. This work has shown that reservoir hydro can enable the integration of intermittent renewables, avoiding the need for costly storage capacity. Additionally, these results demonstrate that solar PV is economically competitive with fuel oil technologies currently being used in Kenya and around the continent. While Kenya’s abundant geothermal resources are seen as a means to reduce the national dependence on diesel power, other countries do not have this domestic resource. As a result, they may be reliant on fuel oil plants longer, increasing the economic and environmental case for solar PV in these countries. For policy-makers and international organizations across the continent eager to reduce dependence on imported fuels and carbon emissions, the development of hydro resources alongside intermittent renewable such as wind and solar may be a viable option.

However, an abundant resource and potential market may not be sufficient to spur solar development. There remain several key barriers
to solar deployment related to regulatory and policy support, public awareness of investment opportunities and data availability. Governments or international organizations keen to promote solar energy in sub-Saharan Africa can address these barriers through a similar set of policy and regulatory options proposed above for Kenya.

7.3 Future Work

This study was designed to provide a top level assessment of the feasibility of solar PV in the Kenyan power system. As such, several simplifying assumptions were used to characterize the Kenyan system and the research questions were limited in scope to the economic and operational feasibility of added solar capacity to an idealized Kenyan system. The results provide a perspective to policy-makers in Kenya and similar developing countries on the potential barriers and opportunities for solar PV deployment. However, future studies can provide a more detailed assessment of the potential role for solar PV to play in Kenya’s future power system.

With this in mind, I propose the following recommendations for further study:

- Wind production, solar production, and demand growth are all potentially highly variable and have been shown to significantly influence system operations. Future models of Kenya’s power system should consider introducing stochasticity to account for uncer-
tainties in these inputs. Better data on wind speeds for proposed plants is also needed.

- The use of a multinode model that includes transmission and distribution networks could increase the accuracy of calculated gains or costs of introducing solar PV. A key attribute in favor of solar is the potential to strategically place it near major load centers (including urban rooftops), alleviating the need for new network infrastructure. However, modeling the network flows may also provide insight as to what geographic and capacity constraints the existing network may impose on potential solar sites.

- If solar generation based on specific proposed sites is used, ground-based measurements from the site should be used instead of the averaging technique employed for this study.

- In order to more accurately evaluate the cost trade-offs between solar and other candidate plants (i.e., geothermal, hydro, wind), the inclusion of transmission costs associated with each plant should also be included.

- Dynamic expansion planning models can provide better detail on the optimal investment schedule.

- While Kenya’s existing reservoir hydro capacity can accommodate high penetrations of solar capacity, additional storage capacity could increase the economic feasibility of solar PV by shifting generation to match evening peak hours. Future studies could
evaluate the value of storage in Kenya and potential expansion planning scenarios that incrementally increase storage and solar PV capacity together.

- This study did not evaluate the potential cost trajectories of solar PV plants. However, recent years have shown significant changes in PV costs and this study found that the cost of PV investments can significantly affect the feasibility of added solar capacity. Future work could evaluate the feasibility of solar PV under different assumed cost trajectories for both solar PV and alternative technologies.

Finally, this study was designed to evaluate if solar PV was a feasible option to address unmet demand and meet medium-term demand growth in Kenya. An alternative question would be to assess which technology is the best candidate to meet these same challenges. As this study has shown, the potential gains that solar PV could provide to the Kenyan system through displaced diesel power and reduced instances of load shedding were limited because PV production did not correspond with the system’s peak demand. In this case CSP or wind power, capable of producing during the evening hours, should be considered in future analyses. These technologies could also be interoperated with existing hydropower resources and eliminate the need for leased diesel capacity in the existing system and reduce fossil-fuel based production in the future.
Appendix A

Hydro Rule Curves

This table contains the monthly minimum reservoir volumes required for each hydro plant (Mm³).

<table>
<thead>
<tr>
<th>Month</th>
<th>Masinga</th>
<th>Kamburu</th>
<th>Gitaru</th>
<th>Kindaruma</th>
<th>Kiambere</th>
<th>Turkwel</th>
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<td>17.7</td>
<td>6.1</td>
<td>553.0</td>
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<td>17.7</td>
<td>6.1</td>
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<td>103.0</td>
<td>19.0</td>
<td>6.1</td>
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<td>257.1</td>
</tr>
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<td>June</td>
<td>1560.0</td>
<td>103.0</td>
<td>19.0</td>
<td>6.1</td>
<td>585.0</td>
<td>325.8</td>
</tr>
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<td>17.7</td>
<td>6.1</td>
<td>585.0</td>
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<td>527.0</td>
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<td>19.0</td>
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<td>19.0</td>
<td>6.1</td>
<td>585.0</td>
<td>345.0</td>
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Table A.1: Rule-Curve Levels During Average Hydrology
Appendix B

Hydro Inflows

These plots contain the 47-year historic dataset of inflows used for the model and provided by the plant owner. The inflow data, provided as monthly sums, were converted to equivalent hourly inflows for UC2012 and UC2017.

Figure B-1: Historic inflows for Masinga reservoir
Figure B-2: Historic inflows for Kamburu reservoir

Figure B-3: Historic inflows for Turkwel reservoir
Figure B-4: Historic inflows for Sondu run-of-river plant
Appendix C

GAMS Code of UC2012

The following is the raw GAMS code used in UC2012.

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   ''*EpOpt 1e-9'/''EpRHS 1e-5'/''SimDisplay 1'/''MIPDisplay 0'/
   ''BarDisplay 1'/''iis yes' /

$Title Kenya UC2012 Static expansion planning model
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* solve the optimization problems until optimality
option OptcR = 0.10 ;

* definitions
sets
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   /p1*p17520/
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<td>generating unit</td>
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<td>ruh</td>
<td>(r,g) Reservoir upstream of hydro plant g</td>
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<td>Res_Gitaru . GITARU_TANA</td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>
Res_Kindaruma . KINDARUMA_TANA
Res_Kiambere . KIAMBERE_TANA /

hur  (g,r) Hydro plant g upstream of reservoir
/MASINGA_TANA . Res_Kamburu
KAMBURU_TANA . Res_Gitaru
GITARU_TANA . Res_Kindaruma
KINDARUMA_TANA . Res_Kiambere /

rur  (r,r) Reservoir 1 upstream of reservoir 2

alias (r,rr)

PARAMETERS

 pD          (p) hourly load          [GW]   
pSpRes      (p) hourly operating reserve [GW]   
pCNSE       cost of non-served energy    [$k per GWh]
            /840/  
pQmax         (g) maximum output       [GW]   
pQmin         (g) minimum output        [GW]   
pOut         (g) outage rate            [p.u.]   
pk           (g) auxiliary load factor   [p.u.]   
p0           (g) variable o&m cost      [$k per GWh]   

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<table>
<thead>
<tr>
<th>Variable</th>
<th>Type</th>
<th>Definition</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>pFixed</td>
<td>(g)</td>
<td>fixed annual cost</td>
<td>$k per MW</td>
</tr>
<tr>
<td>pLease</td>
<td>(g)</td>
<td>annual leasing cost</td>
<td>$k per MW</td>
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<tr>
<td>pUp</td>
<td>(g)</td>
<td>upward ramping rate</td>
<td>GW per h</td>
</tr>
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<td>pDown</td>
<td>(g)</td>
<td>downward ramping rate</td>
<td>GW per h</td>
</tr>
<tr>
<td>pF</td>
<td>(g)</td>
<td>fuel cost</td>
<td>$k per Mth</td>
</tr>
<tr>
<td>pAlpha</td>
<td>(g)</td>
<td>variable fuel consumption</td>
<td>Mth per GWh</td>
</tr>
<tr>
<td>pBeta</td>
<td>(g)</td>
<td>fixed fuel consumption</td>
<td>Mth per h</td>
</tr>
<tr>
<td>pGamma</td>
<td>(g)</td>
<td>fuel consumption at start up</td>
<td>Mth</td>
</tr>
<tr>
<td>pResmax</td>
<td>(r)</td>
<td>maximum reservoir volume</td>
<td>Mm3</td>
</tr>
<tr>
<td>pResmin</td>
<td>(r)</td>
<td>minimum reservoir volume</td>
<td>Mm3</td>
</tr>
<tr>
<td>pInflow</td>
<td>(p,r)</td>
<td>inflow in active year</td>
<td>Mm3 per h</td>
</tr>
<tr>
<td>pInflowsc</td>
<td>(year,p,r)</td>
<td>inflow into reservoir</td>
<td>Mm3 per h</td>
</tr>
<tr>
<td>pProdFunc</td>
<td>(g)</td>
<td>prod function of turbine</td>
<td>GWh per Mm3</td>
</tr>
<tr>
<td>pw0</td>
<td>(r)</td>
<td>initial reservoir volume</td>
<td>Mm3</td>
</tr>
<tr>
<td>pw0sc</td>
<td>(r)</td>
<td>res level from previous year</td>
<td>Mm3</td>
</tr>
<tr>
<td>pwEOY</td>
<td>(year,r)</td>
<td>end-of-year reservoir level</td>
<td>Mm3</td>
</tr>
<tr>
<td>pwFin</td>
<td>(p,r)</td>
<td>regulated min res level</td>
<td>Mm3</td>
</tr>
<tr>
<td>pInsol</td>
<td>(p)</td>
<td>rated solar insolation</td>
<td>p.u.</td>
</tr>
<tr>
<td>pPvplant</td>
<td></td>
<td>size of pv plant</td>
<td>GW</td>
</tr>
<tr>
<td>pQsc</td>
<td>(year,p,g)</td>
<td>production of the unit</td>
<td>GW</td>
</tr>
<tr>
<td>pQ1sc</td>
<td>(year,p,g)</td>
<td>net power above min load</td>
<td>GW</td>
</tr>
<tr>
<td>pPNSsc</td>
<td>(year,p)</td>
<td>power non served</td>
<td>GW</td>
</tr>
<tr>
<td>wReservesc</td>
<td>(year,p,r)</td>
<td>res at the end of period</td>
<td>Mm3</td>
</tr>
<tr>
<td>pSGsc</td>
<td>(year,p)</td>
<td>solar generation</td>
<td>GW</td>
</tr>
</tbody>
</table>
pVarCostsc (year,p) Variable operating cost
pFixedCostsc (year,g) Fixed cost and leasing cost
pTotalCostsc (year) Total cost
pMarginalCostsc (year,p) Total marginal cost
pQavg (p,g)
pQdry (p,g)
pQwet (p,g)
pVarCostavg (p)
pVarCostdry (p)
pVarCostwet (p)
pFixedCostavg (g)
pFixedCostdry (g)
pFixedCostwet (g)
pTotalCostavg
pTotalCostdry
pTotalCostwet
pPNSavg (p)
pPNSdry (p)
pPNSwet (p)

VARIABLES
vFobj Obj function of thermal and hydro cost
vVarCost (p) Variable operating cost of active year
vTotalCost Total cost of active year
BINARY VARIABLES

vCommitt (p,g) commitment of the unit [0-1]
vStartup (p,g) startup of the unit [0-1]
vShutdown (p,g) shutdown of the unit [0-1]
vFix (g) commitment of unit during the year [0-1]

POSITIVE VARIABLES

vQ(p,g) prod of the unit in active year [GW]
vQ1(p,g) net power above min stable load [GW]
vPNS(p) power non served in active year [GW]
vReserve(p,r) res in active year [Mm3]
vS(p,r) spillage [Mm3]
vSG(p) solar generation in active year [GW]
vThUpSRv(p) Thermal Upward Spinning Reserve [GW]
vHyUpRv(p) Hydro Upward Reserve [GW]

EQUATIONS

eBalance (p) supply demand balance [GW]
eFOBJ Objective function
eVarCost (p) operating cost [$k]
eFix (p,g) fixed cost [$k]
eSpRes (p) operating reserve
eQMax (p,g) max output of a committed unit [GW]
eQMin  (p,g)  min output of a committed unit  [GW]
eStartUpNxt  (p,g)  unit startup in next period
eRampS  (p,t)  limit for upward ramp
eRampB  (p,t)  limit for downward ramp
eReserve  (p,r)  water reserve  [Mm3]
eThUpSRv  (p)  designate available thermal spinning reserves
eHyUpRv  (p)  designate available hydro spinning reserves;

* mathematical formulation

eFOBJ .. vFobj =E= 1e-3*SUM[pa(p),vVarCost(p)]+1e-3*sum(g,vFix(g)*
(pFixed(g)+pLease(g)))

eVarCost(pa(p)).. vVarCost(p) =E= pCNSE*Vpns(p)+SUM[t,pF(t)*[pGamma(t)*
vStartup(p,t) + pBeta(t)*VCommitt(p,t) + pAlfa(t)*vQ(p,t)/pk(t)] +
po(t)*vQ(p,t)/pk(t)] + SUM[h, po(h)*vQ(p,h)]

eFix(p,g) .. vQ(p,g) =l= vFix(g)*pQmax(g);

eBalance(p) .. sum[t,vQ(p,t)]+sum[h,vQ(p,h)]+vSG(p)+vPNS(p) =e= pD(p);

eSpRes(p)$pa(p) .. SUM[t,pQmax(t)*vCommitt(p,t)]+sum[h,pQmax(h)]+vSG(p)
vPNS(p) =g= pD(p) + pSpRes(p);

eQMax(p,t)$pa(p) .. vQ(p,t) =e= vCommitt(p,t)*pk(t)*pQmin(t)+vQ1(p,t);

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eQMin(p,t)$pa(p) .. vQ1(p,t)= l=vCommit(p,t)*pk(t)*(pQmax(t)-pQmin(t));

eStrtUpNxt(p,t)$[pa(p)] .. vCommit(p,t)= e=vCommit(p-1,t)$[ord(p)>1] + vStartup(p,t) - vShutdown(p,t);

eRampS(p,t)$pa(p) .. vQ1(p,t)-vQ1(p-1,t)=L=pUp(t);

eRampB(p,t)$pa(p) .. vQ1(p-1,t)-vQ1(p,t)=L=pDown(t);

eReserve(p,r)$pa(p) .. vReserve(p,r) = e= vReserve(p-1,r)$[ord(p)>1] + pW0sc(r)$[ORD(p)=1]+pInflow(p,r) - vS(p,r) + sum[rur(rr,r),vS(p,rr)] + sum[hur(h,r), vQ(p,h)/pProdfunc(h)] - sum[ruh(r,h), vQ(p,h)/pProdfunc(h)];

eThUpSRv(p)$pa(p) ..
    vThUpSRv(p) = e= SUM[t,pk(t)*pQmax(t)*vCommit(p,t)-vQ(p,t)];

eHyUpRv(p)$pa(p) ..
    vHyUpRv(p) = e= sum[h, pk(h)*pQmax(h)-vQ(p,h)];

*Get input data from excel file

*thermal gen sets
$onecho > input.txt
I=%system.fp%input.xlsx
R=thermalgen!A2:015
O=thermalgen.inc
$offecho
$call =xls2gms @input.txt
table thermalgen(g,*)
$include thermalgen.inc
;

*hydro gen sets
$onecho > input.txt
I="%system.fp%input.xlsx"
R=hydrogen!A2:G9
O=hydrogen.inc
$offecho
$call =xls2gms @input.txt
table hydrogen(g,*)
$include hydrogen.inc
;

*hydro reservoirs
$onecho > input.txt
I="%system.fp%input.xlsx"
R=hydrogen!A12:D18
O=hydrogen.inc
$offecho
$call =xls2gms @input.txt
table hydroles(r,*)
$include hydrogen.inc
;

* Inflows
$onecho > input.txt
I="%system.fp%input.xlsx"
R=inflow!A1:G1129
O=inflow.inc
$offecho
$call =xls2gms @input.txt
Table inflowsc(year,p,r) hourly inflows for each year
$include inflow.inc
;
display inflowsc;

*wFin
$onecho > input.txt
I="%system.fp%input.xlsx"
R=wfin!A1:G26
O=wfin.inc
$offecho
$call =xls2gms @input.txt
Table wfin(p,r) hourly rule curve
$include wfin.inc

;  
display wfin;

*demand
$onecho > input.txt
I="%system.fp%input.xlsx"
R=demand!A1:C17521
0=demand.inc
$offecho
$call =xls2gms @input.txt
table loadinsol(p,*)
$include demand.inc

;

*Assign data from excel tables to model variables
p0  (h) =  hydrogen  (h,'VarOM');
pQmax (h) =  hydrogen  (h,'Qmax');
pQmin (h) =  hydrogen  (h,'Qmin');
pk  (h) =  hydrogen  (h,'GrosstoNetPower');
pFixed (h) =  hydrogen  (h,'FixedOM');
pProdfunc (h) =  hydrogen  (h,'ProdFunc');
\[ p_{\text{Resmax}}(r) = \text{hydrores}(r, \text{maxResVol}) \]
\[ p_{\text{Resmin}}(r) = \text{hydrores}(r, \text{minResVol}) \]
\[ p_{\text{WO}}(r) = \text{hydrores}(r, \text{initResVol}) \]

\[ p_{\text{Alfa}}(t) = \text{thermalgen}(t, \text{varFuelCons}) \]
\[ p_{\text{Beta}}(t) = \text{thermalgen}(t, \text{fixFuelCons}) \]
\[ p_{\text{Gamma}}(t) = \text{thermalgen}(t, \text{StartUpFuel}) \]
\[ p_{\text{Up}}(t) = \text{thermalgen}(t, \text{UpRamp}) \]
\[ p_{\text{Down}}(t) = \text{thermalgen}(t, \text{DownRamp}) \]
\[ p_{\text{F}}(t) = \text{thermalgen}(t, \text{FuelCost})*(1.05) \]
\[ p_{\text{0}}(t) = \text{thermalgen}(t, \text{VarOM}) \]
\[ p_{\text{Qmax}}(t) = \text{thermalgen}(t, \text{QMax}) \]
\[ p_{\text{Qmin}}(t) = \text{thermalgen}(t, \text{Qmin}) \]
\[ p_{\text{Fixed}}(t) = \text{thermalgen}(t, \text{FixedOM}) \]
\[ p_{\text{Lease}}(t) = \text{thermalgen}(t, \text{Lease}) \]
\[ p_{\text{k}}(t) = \text{thermalgen}(t, \text{GrosstoNetPower}) \]

\[ p_{\text{D}}(p) = \text{loadinsol}(p, \text{d})*(1.145) \]
\[ p_{\text{Insol}}(p) = \text{loadinsol}(p, \text{insol}) \]

*Definition of active periods of execution
\[ p_{\text{a}}(p) = \text{YES} (\text{ord}(p)>1) \]

*Solar generation set to zero initially
pvplant = 0;
vSG.up(p) = pvplant \times insol(p) \times 10^{-3};

*The sp reserve is assumed to be equal to the largest dispatched plant
pSpRes(p) = 0.225 \times d(p);

model UC2012 / all /;
UC2012.solprint = 0; UC2012.holdfixed = 1;

* Set limits of the variables
vQ.up(p,g) = qmax(g) \times k(g);
vQ.lo(p,g) = 0;
vReserve.up(p,r) = pResmax(r);
vShutDown.up(p,g) = 1;

* Selection of the optimizer for solving relaxed binary variables
OPTION RMIP = cplex;

* Tolerance for optimization convergence with binary variables
OPTION OPTCR = 0.01;

option iterlim=2e+9;
UC2012.reslim = 2e+9;
*display up to 10 equations in the equation listing
option limrow=15;
pw0sc(r) = pw0(r);

*loop through each scenario with different PV plant sizes and solve
loop(year,
*set the minimum reservoir level to the rule curve
    vReserve.lo(p,r) = pwfin(p,r);
*assign the inflows for the active year
    pInflow(p,r) = pInflowsc(year,p,r);

UC2012.optfile = 1 ;
solve UC2012 USING RMIP MINIMIZING vFOBJ;

*save the solution values for the active year
    pQsc(year,p,g) = vQ.L(p,g);
    pSGsc(year,p) = vSG.up(p);
    pPNSsc(year,p) = vPNS.L(p);
    pVarCostsc(year,p) = vVarCost.L(p);
    pFixedCostsc(year,g) = vFix.up(g)*(pFixed(g)+pLease(g));
    pTotalCostsc(year) = sum(p,vVarCost.L(p))+sum(g,vFix.up(g)*(pFixed(g)+pLease(g)));
    wReservesc(year,p,r) = vReserve.L(p,r);
    pwEOY(year,r) = vReserve.L('p8760',r);
pw0sc(r) = wEOY(year,r);

*** calculate average output values ****
pQavg.L(p,g) = (sum(year, pQsc(year,p,g))/47);
pSGavg.up(p) = (sum(year, pSGsc(year,p))/47);
pPNSavg.L(p) = (sum(year, pPNSsc(year,p))/47);
pVarCostavg.L(p) = (sum(year, pVarCostsc(year,p))/47);
pFixedCostavg.L(g) = (sum(year, pFixedCostsc(year,g))/47);
pTotalCostavg.L = (sum(year, pTotalCostsc(year))/47);

*** calculate average values for dry years ****
pQdry.L(p,g) = (pQsc('y1',p,g)+pQsc('y2',p,g)+pQsc('y6',p,g)+pQsc('y8',p,g)+pQsc('y12',p,g)+pQsc('y13',p,g)+pQsc('y29',p,g)+pQsc('y33',p,g)+pQsc('y37',p,g))/9;
pSGdry.up(p) = (pSGsc('y1',p)+pSGsc('y2',p)+pSGsc('y6',p)+pSGsc('y8',p)+pSGsc('y12',p)+pSGsc('y13',p)+pSGsc('y29',p)+pSGsc('y33',p)+pSGsc('y37',p))/9;
\[
p_{\text{VarCostsc}}(\text{'y13',p}) + p_{\text{VarCostsc}}(\text{'y29',p}) + p_{\text{VarCostsc}}(\text{'y33',p}) + p_{\text{VarCostsc}}(\text{'y37',p}) / 9;
\]

\[
p_{\text{FixedCostdry}.L(g)} = (p_{\text{FixedCostsc}}(\text{'y1',g}) + p_{\text{FixedCostsc}}(\text{'y2',g}) + p_{\text{FixedCostsc}}(\text{'y6',g}) + p_{\text{FixedCostsc}}(\text{'y8',g}) + p_{\text{FixedCostsc}}(\text{'y12',g}) + p_{\text{FixedCostsc}}(\text{'y13',g}) + p_{\text{FixedCostsc}}(\text{'y29',g}) + p_{\text{FixedCostsc}}(\text{'y33',g}) + p_{\text{FixedCostsc}}(\text{'y37',g}) / 9;
\]

*** calculate average values for wet years ***

\[
p_{\text{Qwet}.L(p,g)} = (p_{\text{Qsc}}(\text{'y14',p,g}) + p_{\text{Qsc}}(\text{'y16',p,g}) + p_{\text{Qsc}}(\text{'y17',p,g}) + p_{\text{Qsc}}(\text{'y20',p,g}) + p_{\text{Qsc}}(\text{'y21',p,g}) + p_{\text{Qsc}}(\text{'y30',p,g}) + p_{\text{Qsc}}(\text{'y31',p,g}) + p_{\text{Qsc}}(\text{'y35',p,g}) + p_{\text{Qsc}}(\text{'y41',p,g}) + p_{\text{Qsc}}(\text{'y43',p,g}) / 10;
\]

\[
p_{\text{SGwet}.up(p)} = (p_{\text{SGsc}}(\text{'y14',p}) + p_{\text{SGsc}}(\text{'y16',p}) + p_{\text{SGsc}}(\text{'y17',p}) + p_{\text{SGsc}}(\text{'y20',p}) + p_{\text{SGsc}}(\text{'y21',p}) + p_{\text{SGsc}}(\text{'y30',p}) + p_{\text{SGsc}}(\text{'y31',p}) + p_{\text{SGsc}}(\text{'y35',p}) + p_{\text{SGsc}}(\text{'y41',p}) + p_{\text{SGsc}}(\text{'y43',p}) / 10;
\]

\[
p_{\text{PNSwet}.L(p)} = (p_{\text{PNSsc}}(\text{'y14',p}) + p_{\text{PNSsc}}(\text{'y16',p}) + p_{\text{PNSsc}}(\text{'y17',p}) + p_{\text{PNSsc}}(\text{'y20',p}) + p_{\text{PNSsc}}(\text{'y21',p}) + p_{\text{PNSsc}}(\text{'y30',p}) + p_{\text{PNSsc}}(\text{'y31',p}) + p_{\text{PNSsc}}(\text{'y35',p}) + p_{\text{PNSsc}}(\text{'y41',p}) + p_{\text{PNSsc}}(\text{'y43',p}) / 10;
\]

\[
p_{\text{VarCostwet}.L(p)} = (p_{\text{VarCostsc}}(\text{'y14',p}) + p_{\text{VarCostsc}}(\text{'y16',p}) + p_{\text{VarCostsc}}(\text{'y17',p}) + p_{\text{VarCostsc}}(\text{'y20',p}) + p_{\text{VarCostsc}}(\text{'y21',p}) + p_{\text{VarCostsc}}(\text{'y30',p}) + p_{\text{VarCostsc}}(\text{'y31',p}) + p_{\text{VarCostsc}}(\text{'y35',p}) + p_{\text{VarCostsc}}(\text{'y41',p}) + p_{\text{VarCostsc}}(\text{'y43',p}) / 10;
\]
pFixedCost\text{wet.L}(g) = (pFixedCostsc('y14',g) + pFixedCostsc('y16',g) + pFixedCostsc('y17',g) + pFixedCostsc('y20',g) + pFixedCostsc('y21',g) + pFixedCostsc('y30',g) + pFixedCostsc('y31',g) + pFixedCostsc('y35',g) + pFixedCostsc('y41',g) + pFixedCostsc('y43',g))/10;

* Write the results using text file
$\text{INCLUDE UC2012_RES.INC}$

;
Appendix D

GAMS Code of UC2017

The following is the raw GAMS code used in UC2017.

file COPT / cplex.opt /
put COPT putclose 'LPMethod 4'/StartAlg 4'/AdvInd 0'/*EpInt 1e-9'/*
'EpRHS 1e-5'/SimDisplay 1'/MIPDisplay 0'/BarDisplay 1'/iis yes'/

$Title UC2017build
$onempty onmulti offlisting

* solve the optimization problems until optimality
option OptcR = 0.10 ;

* definitions
sets
    p period /p1*p17520/
year  year
/y1*y47/

pa(p) Time periods active in performance
g generating unit
/KIPEVU1, KIPEVU3, IBERAFRICA1, IBERAFRICA2, TSAVO, RABAI, OLRKARIA1, OLRKARIA2, ORPOWER, GEO, MUMIAS, IMPORT, NGONG, AEOLUS, LTWPP, OSIWO, SONDU_ROR, TURKWEL_TURKWEL, MASINGA_TANA, KAMBURU_TANA, GITARU_TANA, KINDARUMA_TANA, KIAMBERE_TANA/

t (g) thermal unit
/KIPEVU1, KIPEVU3, IBERAFRICA1, IBERAFRICA2, TSAVO, RABAI, OLRKARIA1, OLRKARIA2, ORPOWER, GEO, MUMIAS, IMPORT/

h (g) hydro plant
/SONDU_ROR, TURKWEL_TURKWEL, MASINGA_TANA, KAMBURU_TANA, GITARU_TANA, KINDARUMA_TANA, KIAMBERE_TANA/

w (g) wind plant
/NGONG, AEOLUS, LTWPP, OSIWO/

c candidate plants
/MSD, COAL/

r Hydro reservoir

ruh (r,g) Reservoir upstream of hydro plant g
/ROR . SONDU_ROR
Res_Turkwel . TURKWEL_TURKWEL
Res_Masinga . MASINGA_TANA
Res_Kamburu . KAMBURU_TANA
Res_Gitaru . GITARU_TANA
Res_Kindaruma . KINDARUMA_TANA
Res_Kiambere . KIAMBERE_TANA /

hur (g,r) Hydro plant g upstream of reservoir
/MASINGA_TANA . Res_Kamburu
KAMBURU_TANA . Res_Gitaru
GITARU_TANA . Res_Kindaruma
KINDARUMA_TANA . Res_Kiambere /

rur (r,r) Reservoir 1 upstream of reservoir 2

alias (r,rr)

PARAMETERS

pD (p) hourly load [GW]
pSpRes (p) hourly operating reserve [GW]
pCNSE cost of non-served energy [$k per GWh]
/870/
pQmax (g) maximum output [GW]

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<table>
<thead>
<tr>
<th>Symbol</th>
<th>Type</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>( p_{Q_{\text{min}}} )</td>
<td>(g)</td>
<td>minimum output</td>
<td>[GW]</td>
</tr>
<tr>
<td>( p_{\text{Out}} )</td>
<td>(g)</td>
<td>outage rate</td>
<td>[p.u.]</td>
</tr>
<tr>
<td>( p_k )</td>
<td>(g)</td>
<td>auxiliary load factor</td>
<td>[p.u.]</td>
</tr>
<tr>
<td>( p_0 )</td>
<td>(g)</td>
<td>variable o&amp;m cost</td>
<td>[$k per GWh]</td>
</tr>
<tr>
<td>( p_{\text{Fixed}} )</td>
<td>(g)</td>
<td>fixed annual cost</td>
<td>[$k per MW]</td>
</tr>
<tr>
<td>( p_{U_{p}} )</td>
<td>(g)</td>
<td>upward ramping rate</td>
<td>[GW per h]</td>
</tr>
<tr>
<td>( p_{D_{own}} )</td>
<td>(g)</td>
<td>downward ramping rate</td>
<td>[GW per h]</td>
</tr>
<tr>
<td>( p_F )</td>
<td>(g)</td>
<td>fuel cost</td>
<td>[$k per Mth]</td>
</tr>
<tr>
<td>( p_{\text{Alpha}} )</td>
<td>(g)</td>
<td>variable fuel consumption</td>
<td>[Mth per GWh]</td>
</tr>
<tr>
<td>( p_{\text{Beta}} )</td>
<td>(g)</td>
<td>fixed fuel consumption</td>
<td>[Mth per h]</td>
</tr>
<tr>
<td>( p_{\text{Gamma}} )</td>
<td>(g)</td>
<td>fuel consumption at start up</td>
<td>[Mth]</td>
</tr>
<tr>
<td>( p_{Q_{\text{min(c)}}} )</td>
<td>(c)</td>
<td>minimum output</td>
<td>[GW]</td>
</tr>
<tr>
<td>( p_{\text{Out(c)}} )</td>
<td>(c)</td>
<td>outage rate</td>
<td>[p.u.]</td>
</tr>
<tr>
<td>( p_{k(c)} )</td>
<td>(c)</td>
<td>auxiliary load factor</td>
<td>[p.u.]</td>
</tr>
<tr>
<td>( p_{0(c)} )</td>
<td>(c)</td>
<td>variable o&amp;m cost</td>
<td>[$k per GWh]</td>
</tr>
<tr>
<td>( p_{\text{Fixed(c)}} )</td>
<td>(c)</td>
<td>fixed annual cost</td>
<td>[$k per MW]</td>
</tr>
<tr>
<td>( p_{U_{pc}} )</td>
<td>(c)</td>
<td>upward ramping rate</td>
<td>[GW per h]</td>
</tr>
<tr>
<td>( p_{D_{own(c)}} )</td>
<td>(c)</td>
<td>downward ramping rate</td>
<td>[GW per h]</td>
</tr>
<tr>
<td>( p_{F(c)} )</td>
<td>(c)</td>
<td>fuel cost</td>
<td>[$k per Mth]</td>
</tr>
<tr>
<td>( p_{\text{Alpha(c)}} )</td>
<td>(c)</td>
<td>variable fuel consumption</td>
<td>[Mth per GWh]</td>
</tr>
<tr>
<td>( p_{\text{Beta(c)}} )</td>
<td>(c)</td>
<td>fixed fuel consumption</td>
<td>[Mth per h]</td>
</tr>
<tr>
<td>( p_{\text{Gamma(c)}} )</td>
<td>(c)</td>
<td>fuel consumption at start up</td>
<td>[Mth]</td>
</tr>
<tr>
<td>( p_{\text{Resmax}} )</td>
<td>(r)</td>
<td>maximum reservoir volume</td>
<td>[Mm3]</td>
</tr>
<tr>
<td>( p_{\text{Resmin}} )</td>
<td>(r)</td>
<td>minimum reservoir volume</td>
<td>[Mm3]</td>
</tr>
</tbody>
</table>
\begin{align*}
\text{pInflow} & \quad \text{inflows in active year} \quad \text{[Mm3 per h]} \\
\text{pInflowsc} & \quad \text{inflows into reservoir} \quad \text{[Mm3 per h]} \\
\text{pProdFunc} & \quad \text{prod function of hydro plants} \quad \text{[GWh per Mm3]} \\
\text{pw0} & \quad \text{initial reservoir volume} \quad \text{[Mm3]} \\
\text{pw0sc} & \quad \text{res level from previous year} \quad \text{[Mm3]} \\
\text{pwEOY} & \quad \text{end-of-year reservoir level} \quad \text{[Mm3]} \\
\text{pwFin} & \quad \text{regulated min reservoir level} \quad \text{[Mm3]} \\
\text{pInsol} & \quad \text{rated solar insolation} \quad \text{[p.u.]} \\
\text{pPvplant} & \quad \text{size of pv plant} \quad \text{[MW]} \\
\text{pWind} & \quad \text{wind generation} \quad \text{[GW]} \\
\text{pQsc} & \quad \text{production of the unit} \quad \text{[GW]} \\
\text{pQcsc} & \quad \text{prod of the candidate units} \quad \text{[GW]} \\
\text{pQ1sc} & \quad \text{net power above min load} \quad \text{[GW]} \\
\text{pPNSsc} & \quad \text{power non served} \quad \text{[GW]} \\
\text{wReservesc} & \quad \text{reserve at the end of period} \quad \text{[Mm3]} \\
\text{pSGsc} & \quad \text{solar generation} \quad \text{[GW]} \\
\text{pVarCostsc} & \quad \text{Variable operating cost} \\
\text{pFixedCostsc} & \quad \text{Fixed cost} \\
\text{pFixedCostcsc} & \quad \text{Fixed cost of candidate units} \\
\text{pTotalCostsc} & \quad \text{Total cost} \\
\text{pQavg} & \quad \text{[p,g]} \\
\text{pQavgc} & \quad \text{[p,c]} \\
\text{pQdry} & \quad \text{[p,g]} \\
\text{pQdryc} & \quad \text{[p,c]} 
\end{align*}
\[ p_{Q\text{wet}} \quad (p,g) \]
\[ p_{Q\text{wetc}} \quad (p,c) \]
\[ p_{\text{VarCostavg}} \quad (p) \]
\[ p_{\text{VarCostdry}} \quad (p) \]
\[ p_{\text{VarCostwet}} \quad (p) \]
\[ p_{\text{FixedCostavg}} \quad (g) \quad \text{Average FC} \]
\[ p_{\text{FixedCostavgc}} \quad (c) \]
\[ p_{\text{FixedCostdry}} \quad (g) \quad \text{Dry FC} \]
\[ p_{\text{FixedCostdryc}} \quad (c) \]
\[ p_{\text{FixedCostwet}} \quad (g) \quad \text{Wet FC} \]
\[ p_{\text{FixedCostwetc}} \quad (c) \]
\[ p_{\text{TotalCostavg}} \quad \text{Average TC} \]
\[ p_{\text{TotalCostdry}} \quad \text{Dry year TC} \]
\[ p_{\text{TotalCostwet}} \quad \text{Wet year TC} \]
\[ p_{\text{PNSavg}} \quad (p) \]
\[ p_{\text{PNSdry}} \quad (p) \]
\[ p_{\text{PNSwet}} \quad (p) \]
\[ p_{\text{Capsc}} \quad (\text{year},c) \quad \text{Installed cand technology for each year} \]
\[ p_{\text{Capavg}} \quad (c) \quad \text{Average installed cap} \]
\[ p_{\text{Capdry}} \quad (c) \quad \text{Dry installed cap} \]
\[ p_{\text{Capwet}} \quad (c) \quad \text{Wet installed cap} \]
\[ p_{M} \quad \text{decision var to maintain a linear model} \]/10/

VARIABLES
vFobj  
Obj function of thermal and hydro cost

vVarCost  (p)  Variable operating cost of active year

vTotalCost  
Total cost of active year

BINARY VARIABLES

vCommitt  (p,g)  commitment of the unit  [0-1]
vStartup  (p,g)  startup of the unit  [0-1]
vShutdown  (p,g)  shutdown of the unit  [0-1]
vCommittc  (p,c)  commitment of the unit  [0-1]
vStartupc  (p,c)  startup of the unit  [0-1]
vShutdownc  (p,c)  shutdown of the unit  [0-1]
vFixc  (c)  commitment of unit during the year  [0-1]

POSITIVE VARIABLES

vQ  (p,g)  production of the unit in active year  [GW]
vQc  (p,c)
vQ1  (p,g)  net power dispatch above min stable load  [GW]
vQ1c  (p,c)
vPNS  (p)  power non served in active year  [GW]
vReserve  (p,r)  res at end of period in active year  [Mm3]
vS  (p,r)  spillage  [Mm3]
vSG  (p)  solar generation in active year  [GW]
vThUpSRv  (p)  Thermal Upward Spinning Reserve  [GW]
vHyUpRv  (p)  Hydro Upward Reserve  [GW]
vCap  (c)  Capacity of candidate units  [GW]
vY    (p,c)  Linear representation of vCommit*vCap  [GW]

EQUATIONS

eBalance  (p)  supply demand balance  [GW]
eFOBJ

evCost  (p)  operating cost  [$k]
eSpRes  (p)  operating reserve  [GW]
eQMax  (p,g)  max output of a committed unit  [GW]
eQMin  (p,g)  min output of a committed unit  [GW]
eQMaxc  (p,c)  max output of a committed unit  [GW]
eQMinC  (p,c)  min output of a committed unit  [GW]
eStrtUpNxt  (p,g)  unit startup in next period

eStrtUpNxtc  (p,c)  unit startup in next period
eRampS  (p,t)  limit for upward ramp
eRampB  (p,t)  limit for downward ramp
eRampSc  (p,c)  limit for upward ramp
eRampBc  (p,c)  limit for downward ramp
eReserve  (p,r)  water reserve  [Mm3]
eThUpSRv  (p)  designate available thermal spinning reserves
eHyUpRv  (p)  designate available hydro spinning reserves
eyMin  (p,c)  linearizing candidate constraints
eyZero  (p,c)
eyMax  (p,c)
eCapmax (c);

* mathematical formulation

eFOBJ .. vFobj =E= 1e-3*SUM[pa(p), vVarCost(p)] + 1e-3*sum[g, pFixed(g)*pQmax(g)] + 1e-3*sum[c, pFixedc(c)*vCap(c)]

eVarCost(pa(p)) .. vVarCost(p) =E= pCNSE*Vpns(p) + SUM[t, pF(t)*[pGamma(t)*vStartup(p,t) + pBeta(t)*VCommitt(p,t) + pAlpha(t)*vQ(p,t)/pK(t) + pO(t)*vQ(p,t)/pK(t)] + SUM[h, pO(h)*vQ(p,h)] + SUM[c, pFc(c)*pGammac(c)*vStartupc(p,c) + pBetac(c)*VCommittc(p,c) + pAlphac(c)*vQc(p,c)/pKc(c)]];

eBalance(p) .. sum[t, vQ(p,t)] + sum[h, vQ(p,h)] + sum[w, pWind(w,p)] + sum[c, vQC(p,c)] + vSG(p) + vPNS(p) =E= pD(p);

eYmin(p,c) .. vY(p,c) =l= pM*vCommittc(p,c);

eYzero(p,c) .. -vCap(c) + vY(p,c) =l= 0;

eYmax(p,c) .. vCap(c) - vY(p,c) + pM*vCommittc(p,c) =l= pM;

eCapmax(c) .. vCap(c) =l= pM;

eSpRes(p)$pa(p) .. SUM[t, pQmax(t)*vCommitt(p,t)] + sum[h, pQmax(h)] + vSG(p) + sum[w, pWind(w,p)] + sum[c, vY(p,c)] + vPNS(p) =g= pD(p) + pSpRes(p);

eQMax(p,t)$pa(p) .. vQ(p,t) =e= vCommitt(p,t)*pk(t)*pQmin(t) + vQ1(p,t);
\[ eQMaxc(p,c) \cdot pa(p) \cdot vQc(p,c) = e = vCommittc(p,c) \cdot pkc(c) \cdot pQminc(c) + vQ1c(p,c); \]

\[ eQMin(p,t) \cdot pa(p) \cdot vQ1(p,t) = l = vCommitt(p,t) \cdot pk(t) \cdot (pQmax(t) - pQmin(t)); \]

\[ eQMinc(p,c) \cdot pa(p) \cdot vQ1c(p,c) = l = pkc(c) \cdot (vY(p,c) - vCommittc(p,c) \cdot pQminc(c)); \]

\[ eStrtUpNxt(p,t) \cdot [pa(p)] \cdot vCommitt(p,t) = e = vCommitt(p-1,t) \cdot (ord(p) > 1) + vStartup(p,t) - vShutdown(p,t); \]

\[ eStrtUpNxtc(p,c) \cdot [pa(p)] \cdot vCommittc(p,c) = e = vCommittc(p-1,c) \cdot (ord(p) > 1) + vStartupc(p,c) - vShutdownc(p,c); \]

\[ eRampS(p,t) \cdot pa(p) \cdot vQ1(p,t) - vQ1(p-1,t) = L = pUp(t); \]

\[ eRampB(p,t) \cdot pa(p) \cdot vQ1(p-1,t) - vQ1(p,t) = L = pDown(t); \]

\[ eRampSc(p,c) \cdot pa(p) \cdot vQ1c(p,c) - vQ1c(p-1,c) = L = pUpc(c); \]

\[ eRampBc(p,c) \cdot pa(p) \cdot vQ1c(p-1,c) - vQ1c(p,c) = L = pDownc(c); \]

\[ eReserve(p,r) \cdot pa(p) \cdot vReserve(p,r) = e = vReserve(p-1,r) \cdot [ord(p) > 1] + pW0sc(r) \cdot [ORD(p) = 1] + pInflow(p,r) - vS(p,r) + \text{sum}[rur(rr,r), vS(p,rr)] + \text{sum}[hur(h,r), vQ(p,h)/pProdfunc(h)] - \text{sum}[ruh(r,h), vQ(p,h)/pProdfunc(h)]; \]

\[ eThUpSRv(p) \cdot pa(p) \cdot vThUpSRv(p) = e = \text{SUM}[t, pk(t) \cdot pQmax(t) \cdot vCommitt(p,t) - vQ(p,t)] + \text{SUM}[c, pk(c) \cdot vY(p,c) - vQc(p,c)]; \]

\[ eHyUpRv(p) \cdot pa(p) \cdot vHyUpRv(p) = e = \text{sum}[h, pk(h) \cdot pQmax(h) - vQ(p,h)]; \]
*Get input data from excel file

*thermal gen sets

$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=thermalgen!A2:M14
O=thermalgen.inc
$offecho
$call =xls2gms @input.txt
table thermalgen(g,*)
$include thermalgen.inc
;

*candidate sets

$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=thermalgen!A20:M22
O=thermalgen.inc
$offecho
$call =xls2gms @input.txt
table candgen(c,*)
$include thermalgen.inc
;
*hydrogen sets
$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=hydrogen!A2:H9
O=hydrogen.inc
$offecho
$call =xls2gms @input.txt
table hydrogen(g,*)
$include hydrogen.inc
;

*hydro reservoirs
$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=hydrogen!A12:D18
O=hydrogen.inc
$offecho
$call =xls2gms @input.txt
table hydrores(r,*)
$include hydrogen.inc
;

* Inflows
$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=inflow!A1:G1129
O=inflow.inc
$offecho
$call =xls2gms @input.txt
Table pInflows(year,p,r) hourly inflows for each year
$include inflow.inc
;

*wFin
$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=wfin!A1:G26
O=wfin.inc
$offecho
$call =xls2gms @input.txt
Table pWfin(p,r) hourly rule curve
$include wfin.inc
;

*demand
$onecho > input.txt
I="%system.fp%2017input.xlsx"
R=demand!A1:G17521
O=demand.inc
$offecho
$call =xls2gms @input.txt
table loadinsol(p,*)
$include demand.inc
;

*Assign data from excel tables to model variables
p0  (h) =  hydrogen  (h,'VarOM');
pOut (h) =  hydrogen  (h,'Routtage');
pQmax (h) =  hydrogen  (h,'Qmax');
pQmin (h) =  hydrogen  (h,'Qmin');
pk  (h) =  hydrogen  (h,'GrosstoNetPower');
pFixed (h) =  hydrogen  (h,'FixedOM');
pProdfunc (h) =  hydrogen  (h,'ProdFunc');
pResmax (r) =  hydrores  (r,'maxResVol');
pResmin (r) =  hydrores  (r,'minResVol');
pWO  (r) =  hydrores  (r,'initResVol');
pAlpha (t) =  thermalgen  (t,'varFuelCons');
pBeta (t) =  thermalgen  (t,'fixFuelCons');
pGamma (t) =  thermalgen  (t,'StartUpFuel');
pUp   (t) =  thermalgen  (t,'UpRamp');
\[ p_{\text{Down}}(t) = \text{thermalgen}(t,'\text{DownRamp}'); \]
\[ p_F(t) = \text{thermalgen}(t,'\text{FuelCost}'); \]
\[ p_0(t) = \text{thermalgen}(t,'\text{VarOM}'); \]
\[ p_{\text{Out}}(t) = \text{thermalgen}(t,'\text{Routtage}'); \]
\[ p_{\text{Qmax}}(t) = \text{thermalgen}(t,'\text{QMax}'); \]
\[ p_{\text{Qmin}}(t) = \text{thermalgen}(t,'\text{Qmin}'); \]
\[ p_{\text{Fixed}}(t) = \text{thermalgen}(t,'\text{FixedOM}'); \]
\[ p_k(t) = \text{thermalgen}(t,'\text{GrosstoNetPower}'); \]

\[ p_{\text{Alpha}}(c) = \text{candgen}(c,'\text{varFuelCons}'); \]
\[ p_{\text{Beta}}(c) = \text{candgen}(c,'\text{fixFuelCons}'); \]
\[ p_{\text{Gamma}}(c) = \text{candgen}(c,'\text{StartUpFuel}'); \]
\[ p_{\text{Up}}(c) = \text{candgen}(c,'\text{UpRamp}'); \]
\[ p_{\text{Down}}(c) = \text{candgen}(c,'\text{DownRamp}'); \]
\[ p_{\text{F}}(c) = \text{candgen}(c,'\text{FuelCost}'); \]
\[ p_{\text{O}}(c) = \text{candgen}(c,'\text{VarOM}'); \]
\[ p_{\text{Out}}(c) = \text{candgen}(c,'\text{Routtage}'); \]
\[ p_{\text{Fixed}}(c) = \text{candgen}(c,'\text{FixedOM}'); \]
\[ p_{\text{k}}(c) = \text{candgen}(c,'\text{GrosstoNetPower}'); \]

\[ p_D(p) = \text{loadinsol}(p,'d')(1.12); \]
\[ p_{\text{Insol}}(p) = \text{loadinsol}(p,'\text{insol}'); \]
\[ *p_{\text{wind}}(p) = 0.21; \]
\[ p_{\text{Wind}}('\text{Ngong}',p) = 0.00813; \]
pWind ('Osiwo',p) = 0.01667;
pWind ('Aeolus',p) = 0.02055;
pWind ('LTWPP',p) = 0.16438;

*Definition of active periods of execution
pa(p)=YES$(ord(p)>1);
*pa(p)=YES$(ord(p)<=13140);

*Solar generation set to zero initially
pPvplant = 0;
vSG.up(p) = pPvplant*pInsol(p)*1e-3;

*Investment Cost of Wind
pFixed(w)= 317000;
pQmax('NGONG') = 0.0255;
pQmax('AEOLUS') = 0.0608;
pQmax('OSIWO') = 0.05;
pQmax ('LTWPP') = 0.3;

*The spinning reserve is assumed to be the largest dispatched plant
pSpRes(p) = 0.225;
model UC2017build / all / ;
UC2017build.solprint = 0 ; UC2017build.holdfixed = 1 ;

* Set limits of the variables
vQ.up(p,g) = pQmax(g)*pOut(g);
vQ.lo(p,g) = 0;
vReserve.up(p,r) = pResmax(r);
vShutDown.up(p,g)=1;
vCap.up('Coal') = 0.6*pOutc('Coal');
vCap.up('MSD') = 0.332*pOutc('MSD');
pQminc('Coal') = vCap.l('coal')*0.6;
pQminc('MSD') = vCap.l('MSD')*0.5;

* Selection of the optimizer for solving relaxed binary variables
OPTION RMIP = cplex;

* Tolerance for optimization convergence with binary variables
OPTION OPTCR = 0.01;

option iterlim=2e+9 ;
UC2017build.reslim = 2e+9;
*display up to 10 equations in the equation listing
option limrow=15;
pW0sc(r) = pW0(r);
*loop through each scenario with different PV plant sizes and solve loop(year,
*set the minimum reservoir level to the rule curve
  vReserve.lo(p,r) = pwfin(p,r);
*assign the inflows for the active year
  pInflow(p,r) = pInflowsc(year,p,r);

UC2017build.optfile = 1 ;

  solve UC2017build USING RMIP MINIMIZING vFOBJ;

*save the solution values for the active year
  pQsc(year,p,g) = vQ.L(p,g);
  pQcsc(year,p,c) = vQc.L(p,c);
  pSGsc(year,p) = vSG.up(p);
  pPNSsc(year,p) = vPNS.L(p);
  pVarCostsc(year,p) = vVarCost.L(p);
  pFixedCostsc(year,g) = pFixed(g)*pQmax(g);
  pFixedCostcsc(year,c) = pFixedc(c)*vCap.L(c);
  pTotalCostsc(year) = sum(p,vVarCost.L(p)) + sum(g,pFixed(g) + sum(c, pFixedc(c)*vCap.L(c)));
  pwEOY(year,r) = vReserve.L('p8760',r);
  pWOsc(r) = pwEOY(year,r);
\[ p\text{Capsc}(\text{year},c) = v\text{Cap}.L(c); \]

*** calculate average output values ****

\[ p\text{Qavg}(p,g) = (\text{sum}(\text{year}, p\text{Qsc}(\text{year},p,g))/47); \]
\[ p\text{Qavgc}(p,c) = (\text{sum}(\text{year}, p\text{Qcsc}(\text{year},p,c))/47); \]
\[ v\text{SG}.\text{up}(p) = (\text{sum}(\text{year}, p\text{SGsc}(\text{year},p))/47); \]
\[ p\text{PNSavg}(p) = (\text{sum}(\text{year}, p\text{PNSsc}(\text{year},p))/47); \]
\[ p\text{VarCostavg}(p) = (\text{sum}(\text{year}, p\text{VarCostsc}(\text{year},p))/47); \]
\[ p\text{FixedCostavg}(g) = (\text{sum}(\text{year}, p\text{FixedCostsc}(\text{year},g))/47); \]
\[ p\text{FixedCostavgc}(c) = (\text{sum}(\text{year}, p\text{FixedCostcsc}(\text{year},c))/47); \]
\[ p\text{TotalCostavg} = (\text{sum}(\text{year}, p\text{TotalCostsc}(\text{year}))/47); \]
\[ p\text{Capavg}(c) = (\text{sum}(\text{year}, p\text{Capsc}(\text{year},c))/47); \]

*** calculate average values for dry years ****

\[ p\text{Qdry}(p,g)=(p\text{Qsc}('y1',p,g)+p\text{Qsc}('y2',p,g)+p\text{Qsc}('y6',p,g)+p\text{Qsc}('y8',p,g)+p\text{Qsc}('y12',p,g)+p\text{Qsc}('y13',p,g)+p\text{Qsc}('y29',p,g)+p\text{Qsc}('y33',p,g)+p\text{Qsc}('y37',p,g))/9; \]
\[ p\text{Qdryc}(p,c)=(p\text{Qcsc}('y1',p,c)+p\text{Qcsc}('y2',p,c)+p\text{Qcsc}('y6',p,c)+p\text{Qcsc}('y8',p,c)+p\text{Qcsc}('y12',p,c)+p\text{Qcsc}('y13',p,c)+p\text{Qcsc}('y29',p,c)+p\text{Qcsc}('y33',p,c)+p\text{Qcsc}('y37',p,c))/9; \]
\[ p\text{PNSdry}(p)=(p\text{PNSsc}('y1',p)+p\text{PNSsc}('y2',p)+p\text{PNSsc}('y6',p)+p\text{PNSsc}('y8',p)+p\text{PNSsc}('y12',p)+p\text{PNSsc}('y13',p)+p\text{PNSsc}('y29',p)+p\text{PNSsc}('y33',p)+p\text{PNSsc}('y37',p))/9; \]
\[
p_{\text{PNSsc}}('y8',p) + p_{\text{PNSsc}}('y12',p) + p_{\text{PNSsc}}('y13',p) + p_{\text{PNSsc}}('y29',p) + p_{\text{PNSsc}}('y33',p) + p_{\text{PNSsc}}('y37',p)) / 9;
\]
\[
p_{\text{VarCostdry}}(p) = (p_{\text{VarCostsc}}('y1',p) + p_{\text{VarCostsc}}('y2',p) + p_{\text{VarCostsc}}('y6',p) + p_{\text{VarCostsc}}('y8',p) + p_{\text{VarCostsc}}('y12',p) + p_{\text{VarCostsc}}('y13',p) + p_{\text{VarCostsc}}('y29',p) + p_{\text{VarCostsc}}('y33',p) + p_{\text{VarCostsc}}('y37',p)) / 9;
\]
\[
p_{\text{FixedCostdry}}(g) = (p_{\text{FixedCostsc}}('y1',g) + p_{\text{FixedCostsc}}('y2',g) + p_{\text{FixedCostsc}}('y6',g) + p_{\text{FixedCostsc}}('y8',g) + p_{\text{FixedCostsc}}('y12',g) + p_{\text{FixedCostsc}}('y13',g) + p_{\text{FixedCostsc}}('y29',g) + p_{\text{FixedCostsc}}('y33',g) + p_{\text{FixedCostsc}}('y37',g)) / 9;
\]
\[
p_{\text{FixedCostdryc}}(c) = (p_{\text{FixedCostcsc}}('y1',c) + p_{\text{FixedCostcsc}}('y2',c) + p_{\text{FixedCostcsc}}('y6',c) + p_{\text{FixedCostcsc}}('y8',c) + p_{\text{FixedCostcsc}}('y12',c) + p_{\text{FixedCostcsc}}('y13',c) + p_{\text{FixedCostcsc}}('y29',c) + p_{\text{FixedCostcsc}}('y33',c) + p_{\text{FixedCostcsc}}('y37',c)) / 9;
\]
\[
p_{\text{Capdry}}(c) = (p_{\text{Capsc}}('y1',c) + p_{\text{Capsc}}('y2',c) + p_{\text{Capsc}}('y6',c) + p_{\text{Capsc}}('y8',c) + p_{\text{Capsc}}('y12',c) + p_{\text{Capsc}}('y13',c) + p_{\text{Capsc}}('y29',c) + p_{\text{Capsc}}('y33',c) + p_{\text{Capsc}}('y37',c)) / 9;
\]

*** calculate average values for wet years ***

\[
p_{\text{Qwet}}(p,g) = (p_{\text{Qsc}}('y14',p,g) + p_{\text{Qsc}}('y16',p,g) + p_{\text{Qsc}}('y17',p,g) + p_{\text{Qsc}}('y20',p,g) + p_{\text{Qsc}}('y21',p,g) + p_{\text{Qsc}}('y30',p,g) + p_{\text{Qsc}}('y31',p,g) + p_{\text{Qsc}}('y35',p,g) + p_{\text{Qsc}}('y41',p,g) + p_{\text{Qsc}}('y43',p,g)) / 10;
\]
\[
p_{\text{Qwetc}}(p,c) = (p_{\text{Qcsc}}('y14',p,c) + p_{\text{Qcsc}}('y16',p,c) + p_{\text{Qcsc}}('y17',p,c) + p_{\text{Qcsc}}('y20',p,c) + p_{\text{Qcsc}}('y21',p,c) + p_{\text{Qcsc}}('y30',p,c) + p_{\text{Qcsc}}('y31',p,c) + p_{\text{Qcsc}}('y35',p,c) + p_{\text{Qcsc}}('y41',p,c) + p_{\text{Qcsc}}('y43',p,c)) / 10;
\]
\[
pQcsc('y20',p,c)+pQcsc('y21',p,c)+pQcsc('y30',p,c)+pQcsc('y31',p,c)+pQcsc('y35',p,c)+pQcsc('y41',p,c)+pQcsc('y43',p,c)/10;
\]
\[
\]
\[
\]
\[
pFixedCostwet(g)=(pFixedCostsc('y14',g)+pFixedCostsc('y16',g)+pFixedCostsc('y17',g)+pFixedCostsc('y20',g)+pFixedCostsc('y21',g)+pFixedCostsc('y30',g)+pFixedCostsc('y31',g)+pFixedCostsc('y35',g)+pFixedCostsc('y41',g)+pFixedCostsc('y43',g))/10;
\]
\[
pFixedCostwetc(c)=(pFixedCostcsc('y14',c)+pFixedCostcsc('y16',c)+pFixedCostcsc('y17',c)+pFixedCostcsc('y20',c)+pFixedCostcsc('y21',c)+pFixedCostcsc('y30',c)+pFixedCostcsc('y31',c)+pFixedCostcsc('y35',c)+pFixedCostcsc('y41',c)+pFixedCostcsc('y43',c))/10;
\]
\[
pCapwet(c)=(pCapsc('y14',c)+pCapsc('y16',c)+pCapsc('y17',c)+pCapsc('y20',c)+pCapsc('y21',c)+pCapsc('y30',c)+pCapsc('y31',c)+pCapsc('y35',c)+pCapsc('y41',c)+pCapsc('y43',c))/10;
\]
pCapsc('y43',c)/10;

* Write the results using text file

$INCLUDE UC2017_RES.INC

;
Appendix E

Scenario Results

The charts below contain the weekly dispatch results for each scenario tested in UC2012 and UC2017.

Figure E-1: Weekly generation profile in the 100 MW scenario (2012)
Figure E-2: Weekly generation profile in the 200 MW scenario (2012)

Figure E-3: Weekly generation profile in the 300 MW scenario (2012)
Figure E-4: Weekly generation profile in the 400 MW scenario (2012)

Figure E-5: Weekly generation profile in the 600 MW scenario (2012)
Figure E-6: Weekly generation profile in the 700 MW scenario (2012)

Figure E-7: Weekly generation profile in the 800 MW scenario (2012)
Figure E-8: Weekly generation profile in the 900 MW scenario (2012)

Figure E-9: Weekly generation profile in the 1000 MW scenario (2012)
Figure E-10: Weekly generation profile in the 100 MW scenario (2017)

Figure E-11: Weekly generation profile in the 200 MW scenario (2017)
Figure E-12: Weekly generation profile in the 300 MW scenario (2017)

Figure E-13: Weekly generation profile in the 400 MW scenario (2017)
Figure E-14: Weekly generation profile in the 600 MW scenario (2017)

Figure E-15: Weekly generation profile in the 700 MW scenario (2017)
Figure E-16: Weekly generation profile in the 800 MW scenario (2017)

![Weekly Generation Profile: June 800 MW Average Scenario](image)

Figure E-17: Weekly generation profile in the 900 MW scenario (2017)

![Weekly Generation Profile: June 900 MW Average Scenario](image)
Figure E-18: Weekly generation profile in the 1000 MW scenario (2017)
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