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Socio-Technical Innovation for a Low Carbon Energy Future

By

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A dissertation submitted in partial satisfaction of the

requirements for the degree of

Doctor of Philosophy

in

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of the

University of California, Berkeley

Committee in charge:

Professor Daniel M. Kammen, Chair

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Professor Charisma S. Acey

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Socio-Technical Innovation for a Low Carbon Energy Future

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Nkiruka Ifunanya Avila

ABSTRACT

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by

Nkiruka Ifunanya Avila

Doctor of Philosophy in Energy and Resources

University of California, Berkeley

Professor Daniel M. Kammen, Chair

This dissertation develops a set of analytical tools and conceptual frameworks to explore the socio-technical implications of transitioning to a low carbon energy future. The chapters here investigate the energy challenges in Sub-Saharan Africa and analyze power expansion pathways in Nigeria and Kenya, outline the development of a novel electricity modeling tool, and conceptualize an energy sovereignty framework to enable people-centered energy planning approaches.

Chapter 2 presents an overview of Africa's energy systems and the role renewable energy can play in supporting sustainable development in Africa, with a main focus on the challenges in Sub-Saharan Africa. I synthesize the most prominent papers in the past five years. I review the literature concerning the scale of generation expansion needed to achieve universal access in the region, the challenges of power sector finance, and the need for people-centered planning paradigms. Through an extensive literature review, I assess the capacity expansion needs of the region and highlight the policy lessons that enable private power sector investment such as transparent regulatory and procurement policies. I also present a critique of the socio-political implications of increased foreign investment in the region's power sector. Finally, I present several studies that explore the need for people-centered planning approaches in order to achieve more equitable energy systems for all. I argue that renewable energy presents opportunities to achieve power systems expansion in an economically, environmentally and socially sustainable manner. To do this, Sub-Saharan Africa must adapt its planning strategies to holistically address the technical, economic and socio-political challenges it faces.

Chapter 3 takes a deep-dive from an overview of Sub-Saharan Africa to a focus on Nigeria. I develop a first-order capacity expansion model to analyze power expansion scenarios in Nigeria. Nigeria serves as a case of countries with significant electricity demand growth that is constrained by under-developed grid infrastructure. I illustrate how the dependence on natural gas for generation has stifled the nation's power supply, assess the role of renewable energy in meeting the nation's electricity demand growth, and compare the cost of its current power generation expansion pathways to cost-optimized pathways. Using the capacity

expansion model, I find that Nigeria's current energy policy, known as Vision 30:30:30, perpetuates this heavy reliance on natural gas and significantly underestimates the role of solar energy in the future electricity mix. I also identify and assess lower cost alternative pathways which do not require any coal and nuclear generation expansion unlike the Vision 30:30:30 pathway. The results show that Nigeria will have to install at least an additional 38 GW by 2030 to keep up with grid-based demand growth alone - about eight times the current operational capacity. This chapter reveals Nigeria's need for an energy policy reform that reduces its dependency on natural gas, eschews coal and nuclear expansion, and harnesses its abundant solar potential using centralized and distributed renewable energy technologies.

Chapter 4 outlines my development of a novel open-access electricity modeling tool known as PROGRESS (Programmable Resource Optimization for Growth in Renewable Energy and Sustainable Systems). PROGRESS enables generation expansion modeling for countries with low availability and access to power systems data. The design of sustainable electricity systems needed to fuel development in regions with low electrification rates (such as Sub-Saharan Africa) requires context-specific power system modeling. Modeling data requirements for these regions, however, can be challenging for researchers and other stakeholders to access. This chapter presents a proof-of-concept description to show how PROGRESS works and then presents preliminary results for generation capacity expansion using the case of Kenya.

Chapter 5 presents what is, for me, the most critical aspect of this dissertation. I explore how transitioning to low carbon energy systems and achieving universal electricity access will require not only an extensive redesign of the existing energy infrastructure but also a rethinking of energy planning approaches. I argue that innovation in decentralized and distributed energy technology transforms people from mere consumers to prosumers by empowering them to plan for their energy autonomously. I aim to connect the rise of prosumers with long-standing social movements that call for just, fair and sustainable energy systems. I draw from a rich literature of socio-energy concepts that aim to incorporate social and human dimensions into energy planning. I focus on energy justice, energy democracy, and I introduce energy sovereignty. I synthesize how these concepts together emphasize critical considerations for energy planning: "energy for whom, for what, and at whose costs?" I also introduce an additional consideration: "energy by whom?" and I conceptualize its framework in relation to electricity provision. I propose that "energy by whom?" is an essential question for re-envisioning a new energy paradigm and designing a low-carbon energy future.

Overall, this dissertation contributes analytical and conceptual tools for low carbon energy systems, which together provide novel socio-technical approaches for planning towards a low carbon energy future, and urge on the paradigm shift to just and sustainable energy for all.

To my beloved mother, Franca Obiageli

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Chapter 1

Introduction

Planning is the process of developing strategies to prepare for and achieve a future goal in an organized way. Planning takes various forms in different fields. Specifically, in the field of critical urban planning, it can be described as a technical and political process concerned with the welfare of people, control of the use of land, design of the urban environment (including transportation and communication networks), and protection and enhancement of the natural environment. Energy and its infrastructure are fundamental concerns for urban and regional planning. Energy planning exists as a field on its own and describes the process of designing and analyzing energy systems with the goal of meeting energy needs over time. I draw mainly from the fields of critical urban planning and long-term energy planning to address challenges related to the global transition to a low carbon energy future.

I begin in Sub-Saharan Africa, where a majority of the countries face multi-faceted and persistent energy access challenges, and various public and private stakeholders are planning towards universal energy access. I will be focusing on one of these facets – generation capacity expansion. There is a lack of analysis of the specific scale of the technological challenges and the opportunities for on-grid renewables to address the electricity gap between demand and supply. The first part of my dissertation provides an account of the challenges of closing the electricity gap in Sub-Saharan Africa and explores the available opportunities for on-grid renewable energy technologies to expand electricity supply in Sub-Saharan Africa. The second part of my dissertation deep-dives into the case of Nigeria and explores grid expansion pathways to reliable electricity supply. I investigate and compare the tradeoffs of various supply expansion pathways in Nigeria and compare my results to the existing published power plans.

I then outline my development process of a novel open-access power systems optimization tool – PROGRESS - that allows power systems modeling in low data contexts and is readily adaptable to country-specific realities. I attempt to broaden the range of people who have access to planning by increasing the accessibility and adaptability of modeling tools.

Finally, I argue that techno-economic planning approaches such as grid modeling are beneficial to electricity planning but do not enable planners to see and therefore plan in the context of the full picture. My goal is to broaden planning considerations by pushing forward an emerging concept: energy sovereignty. Energy sovereignty is a critical conceptual lens through which I explore a novel planning question: “energy by whom?” Existing concepts explore “energy for what and for whom?”, but are yet to consider by whom. The rise of prosumers and increasing access to decentralized energy innovation makes this an essential consideration.

Chapter 2

The role of renewable energy in bridging Africa's electricity gap

2.1 Introduction

Despite its energy resource abundance, Africa is the most electricity-poor region in the world due to its undeveloped electricity infrastructure [1]–[3]. There are vast disparities in electrification rates among African countries, particularly in Sub-Saharan Africa. The average per capita electricity consumption in sub-Saharan Africa is 488 kWh a year – the lowest per capita electricity consumption in the world, compared to North Africa estimated at 1,500 kWh per capita [4], [5]. When South Africa is excluded, annual electricity consumption in Sub-Saharan Africa is only about 150 kWh per capita. Household electrification rates vary widely as well; household electrification rates in Ghana, Nigeria, Senegal are higher than in Burundi, Chad, Liberia, Malawi, and South Sudan [6]. South Africa also has high electricity access rates (> 90%) compared to the rest of the continent. Rural areas are often not connected to national electricity grids and therefore have much lower rates: nearly half – 24 out of 50 countries – have access rates in the single digits [7]. However, a grid connection does not guarantee electricity services as urban populations have grid connections are unreliable and insecure [8]–[14]. Nigeria, for example, has so many power outages, that their systems are dubbed “epileptic” and the World Bank estimates that 25 sub-Saharan African countries are facing an energy crisis, evidenced by rolling blackouts [7].

Sub-Saharan Africa has high income and wealth inequality, which leads to vast differences in consumers' desire and willingness to pay for electricity. Its countries display large disparities in electricity costs, with South Africa and Zambia among the lowest, and Djibouti and Gabon among the highest. Access to electricity is also highly unequal, even among people who are connected to the grid. Some people just cannot afford to consume electricity despite being connected. Therefore, they cannot consume enough electricity to make use of modern energy services. Many also suffer disproportionately high levels of service interruption and do not have enough income to depend on expensive on-site diesel generators like wealthier people in the same region. There are technological, geographical, cultural, and social distinctions that suggest the region should define its target standard of living and type of energy services to be pursued, rather than comparing itself with wealthier countries.

Despite increased electrification efforts globally, electrification efforts do not keep pace with the rapid population growth in sub-Saharan Africa, and the share of the population without electricity remains high in that region [15]. Therefore, Africa faces an electricity gap in two dimensions: a mismatch between supply and demand in grid-connected regions, and a lack of access in off-grid regions [16].

Access to electricity underpins many broader development goals for education, health, and economic prosperity [17], [18]. For Africa to successfully increase affordable and reliable access to electricity, its installed electricity generation capacity will need to grow exponentially. Renewable energy is particularly well suited for Africa because seven of the ten most suitable countries for renewable energy potential is in Africa and renewable energy has strong synergies with many of the sustainable development goals [19], [20]. Also, renewable energy is key to developing and expanding energy services in Africa without exacerbating climate change owing to its abundance of renewable resources [1].

2.2 Current State of Electricity Access

More than 600 million people lack access to electricity in Sub-Saharan Africa, and millions more are connected to an unreliable grid that does not meet their daily energy service needs. Most countries in this region have electricity access rates of about 20%, and two out of three people lack access to modern energy services. Figure 2.1 shows that electrification rates in Sub-Saharan Africa (excluding South Africa) are in stark contrast with North Africa. I focus my analysis on Sub-Saharan Africa – the regional classification of countries is shown in Table A 1.

3. Energy access can be achieved through a variety of technologies, so its measure should be technology-neutral.

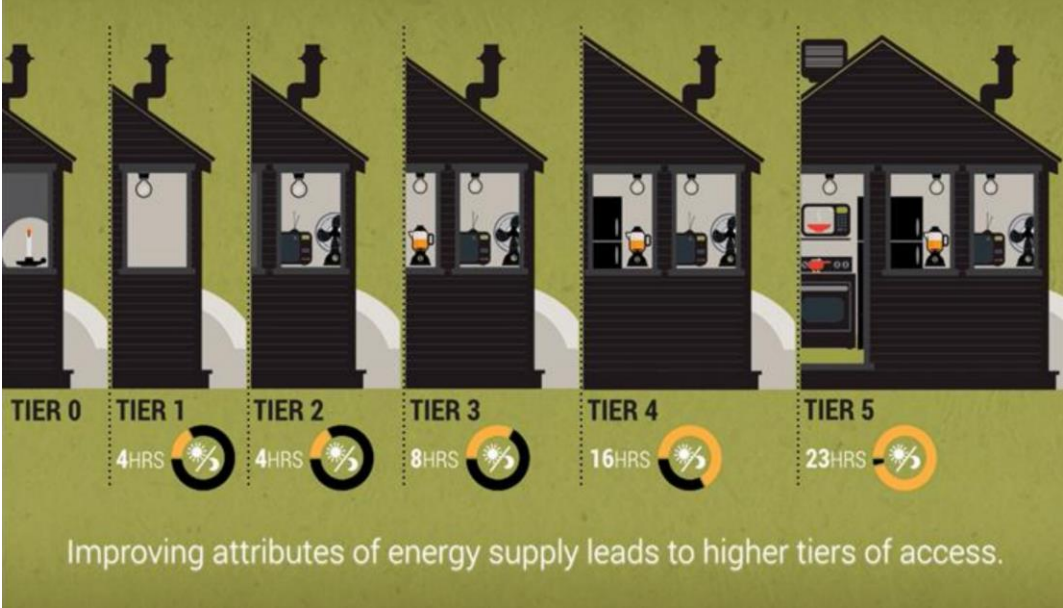


Figure 2.2: The multi-tier energy access framework

2.3 The Scale of Generation Expansion

The primary reasons behind lack of electricity access in Sub-Saharan Africa are interdependent. They include the lack of generation capacity to supply power to grid-connected regions, absence of reliable transmission and distribution grid infrastructure to deliver generated power, regulatory impediments to providing steady revenue for maintenance of existing infrastructure and investment in new generation capacity, insecurity of diesel and natural gas supply to generators, and the dispersity of population in remote areas [16].

In particular, the generation capacity in the region is stagnant and decreasing in some countries. As of 2012, Sub-Saharan Africa had a total grid-connected power generation capacity of only 83 GW. Sub-Saharan Africa, excluding South Africa, has a combined capacity of only 36 GW, and just 13 of its countries had power systems larger than 1 GW [22]. The Republic of Korea generates as much electricity as Sub-Saharan Africa. Today, Sub-Saharan Africa's power grid has an installed generation capacity of about 100 GW— with half of the region's capacity located in South Africa. This capacity is about 0.1 kW per capita, in stark contrast with wealthier economies that have installed capacities ranging from 1 to 3 kW per capita [4], [22].

Between 1990 and 2013, only 24.85 GW of new generation capacity was added across Sub-Saharan Africa, of which South Africa accounted for 9.2 GW [22], [23]. There has been relatively significant growth since 2000 - 13.8 GW of generation capacity has been added, but some countries have been losing capacity over time as a result of poor maintenance [24]. Eberhard et al. estimate that only an average of 1-2 GW of capacity has been added annually in Sub-Saharan Africa over the past decade, short of the World Bank's estimate of an 8 GW capacity addition requirement through 2015 [23]. The inability to provide reliable electricity has led to the prolific growth of inefficient and expensive on-site diesel self-generation. The overall economic cost of power outages is estimated as an average of 2% of the Sub-Saharan Africa countries' Gross Domestic Product (GDP) using load-shedding data collected by the World Bank [25]. Backup generators are not only insecure due to precarious and volatile diesel supply, but they are also expensive, costing about 300% more than electricity from the grid [8], [26], [27].

The International Energy Agency (IEA) estimates that electricity demand in the region grew by about 35% from 2000 to 2012 to reach 352 TWh. The highest demand in sub-Saharan Africa is in Nigeria and South Africa, which together account for about 40% of total demand. The IEA forecasts that total demand for electricity in Africa will increase at an average rate of 4% a year through 2040 to reach 1,570 TWh, including captive power estimates (Figure 2.3) [5]. There is significant uncertainty in most demand projections and historical demand estimates due to unreliable data on captive power and self-generation.

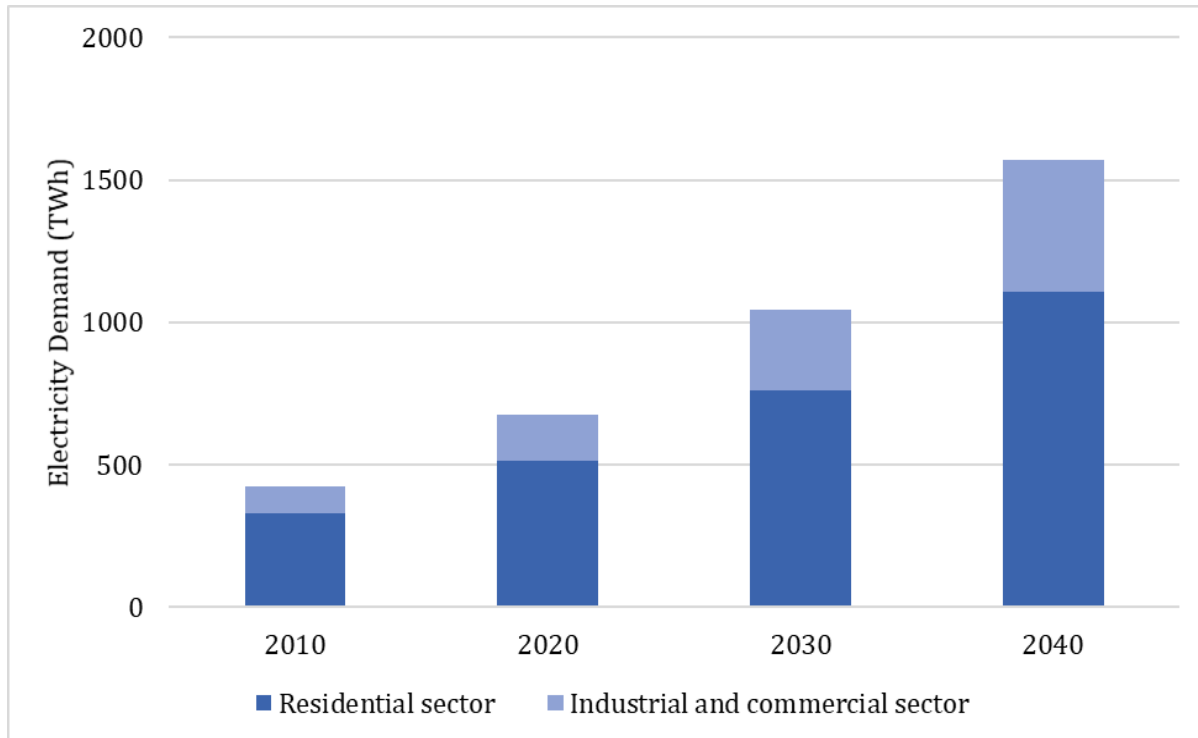


Figure 2.3: Estimated electricity demand growth in Sub-Saharan Africa.

Sub-Saharan Africa will need to expand its generation capacity significantly to accommodate and serve its growing population¹. I update simple heuristics developed by Bazilian et al. [2] to estimate an electricity generation capacity per capita requirement as a proxy for the latent demand of the region by 2030. I restrict our calculation to Sub-Saharan Africa - excluding South Africa and extend the time frame to 2040 to illustrate the scale of generation capacity needed to achieve full access in the region. I present two scenarios of generation, based on the same scenarios used in [2]. The scenarios are as follows:

- i) Full Enhanced Access: The total population reaches a target of 800 MW/ million people² by 2040
- ii) Full Access: The total population reaches a target of 400 MW/ million people by 2040

The results illustrate the astounding amount of generation capacity growth needed to achieve different levels of access in Sub-Saharan Africa. I find that in order to reach 400 MW/million people by 2040, the region will need to add an average of 25 GW per year;

¹ Population growth forecasts are taken from United Nations, Department of Economic and Social Affairs, Population Division (2017). World Population Prospects: The 2017 Revision, custom data acquired via website.

² 800 MW/million is approximately the current generation capacity per capita of South Africa as of 2016.

compared to the region’s current pace of expansion of 2 GW per year. Total capacity addition of 620 GW is needed to reach 400 MW/million people and 1300 GW to reach 800 MW/million people by 2040. These estimates assume a load factor of 50%, based on average load factor estimates in North Africa from 2000-2008 [2].

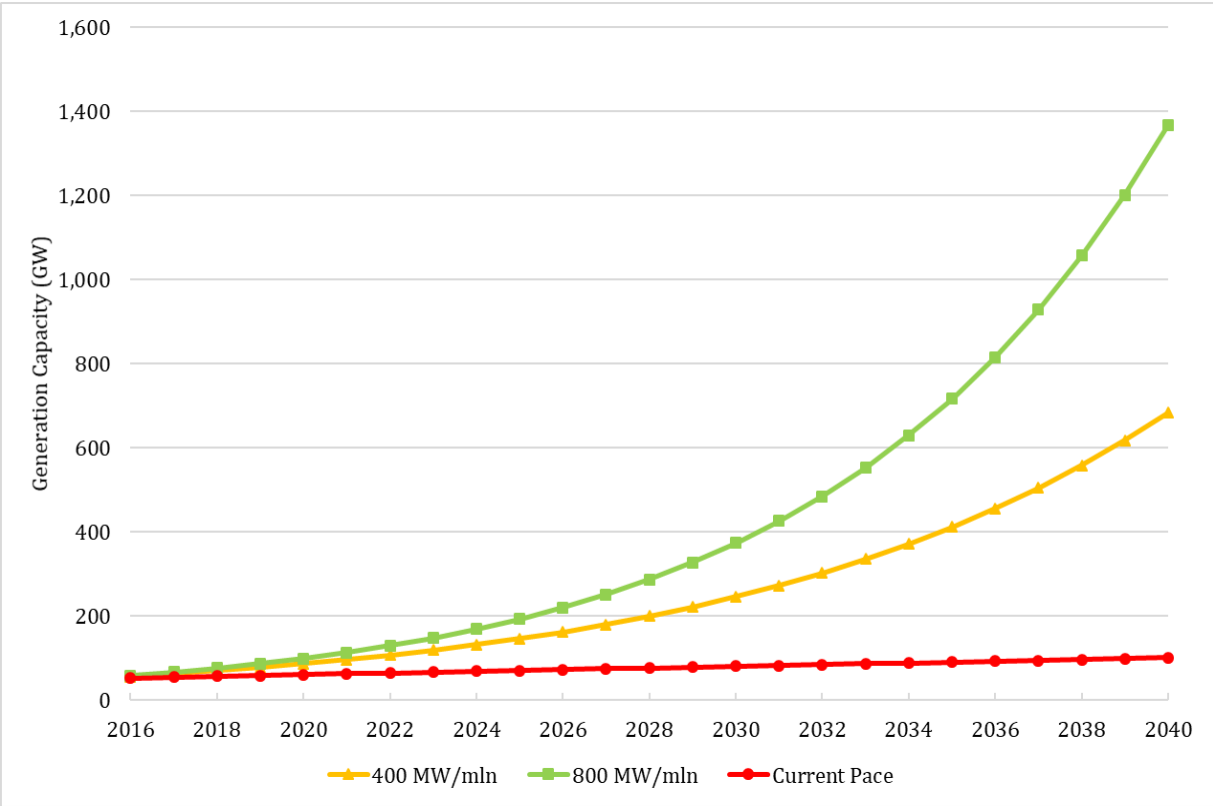


Figure 2.4: Projections for generation capacity requirements in Sub-Saharan Africa by 2040 (excluding South Africa)

The region has sufficient energy potential to meet this expansion. The electricity generation potential in Sub-Saharan Africa is estimated at 1200 GW of gas, coal, hydropower, geothermal and wind, and about 10,000 GW of solar photovoltaic [4]. Most of its coastal countries have high wind potential, totaling about 109 GW. The East Africa Rift Valley offers an estimated 15 GW of geothermal capacity, mainly in Ethiopia and Kenya. Because the region is home to the Congo and the Nile Rivers, among the world’s longest rivers, it also has some of the largest hydropower resources in the world. Its exploitable hydropower is estimated at 350 GW, located mainly in Angola, Cameroon, the Democratic Republic of Congo (DRC), Ethiopia, and Gabon. Its fossil energy resources include recent oil and gas discoveries, and it has about 400 GW of natural gas potential. Coal resources are estimated at 300 GW, mainly in Botswana, Mozambique, and South Africa [4].

2.4 Renewable Energy Grid Integration

About 70% of Africa’s installed capacity is from fossil fuels [4]. The electricity mix is predominantly gas-fueled in Northern Africa and coal-fueled in Sub-Saharan Africa (South Africa’s generation is 90% coal). Hydropower counts for about 75% of the installed generation in Central Africa [13]. Recently, renewable energy development is breaking through on the continent - both in scale and price [24]. Africa has exceptional solar, wind, geothermal, hydropower and biomass resource potential, both on a per capita basis and regarding resource diversity [1], [16]. Several papers have carried renewable energy resource potential assessment regions in Africa [28]–[30]. Table 1 outlines the maximum technical potential for renewable energy in Africa, all of which are largely untapped. The estimates for concentrated solar power, solar PV and wind are from IRENA’s 2014 report using Global Atlas for Renewable Energy Maps [31]. Estimates for hydropower and geothermal are obtained from an earlier analysis carried out by IRENA in 2011 [2], [32]. Most countries in Sub-Saharan Africa have renewable energy potentials that exceed their current consumption. For example, Angola, Sudan, and Zambia could have annual productions from solar, wind, hydro, geothermal, and biofuels that is about 25 times their current energy consumption under realistic assumptions of technical feasibility [14]. Figure 2.5 shows the solar irradiation across Africa [33] and Figure 2.6 compares the renewable energy potential across the region [4]. Table 2.1 shows the technical potential by resource and by region [2], [31].

Region	Concentrated Solar Power [TWh/yr]	Solar PV [TWh/yr]	Wind [TWh/yr]	Geothermal [TWh/yr]	Hydropower [TWh/yr]
Central Africa	29,909	61,643	12,395	-	1,057
Eastern Africa	175,777	219,481	165,873	16	578
Northern Africa	93,544	109,033	130,316	-	78
Southern Africa	149,610	162,817	108,235	-	26
Western Africa	103,754	103,754	40,846	-	105
Total	552,594	656,728	457,665	16	1,844

Table 2.1: Technical potential for renewable energy in Africa by region

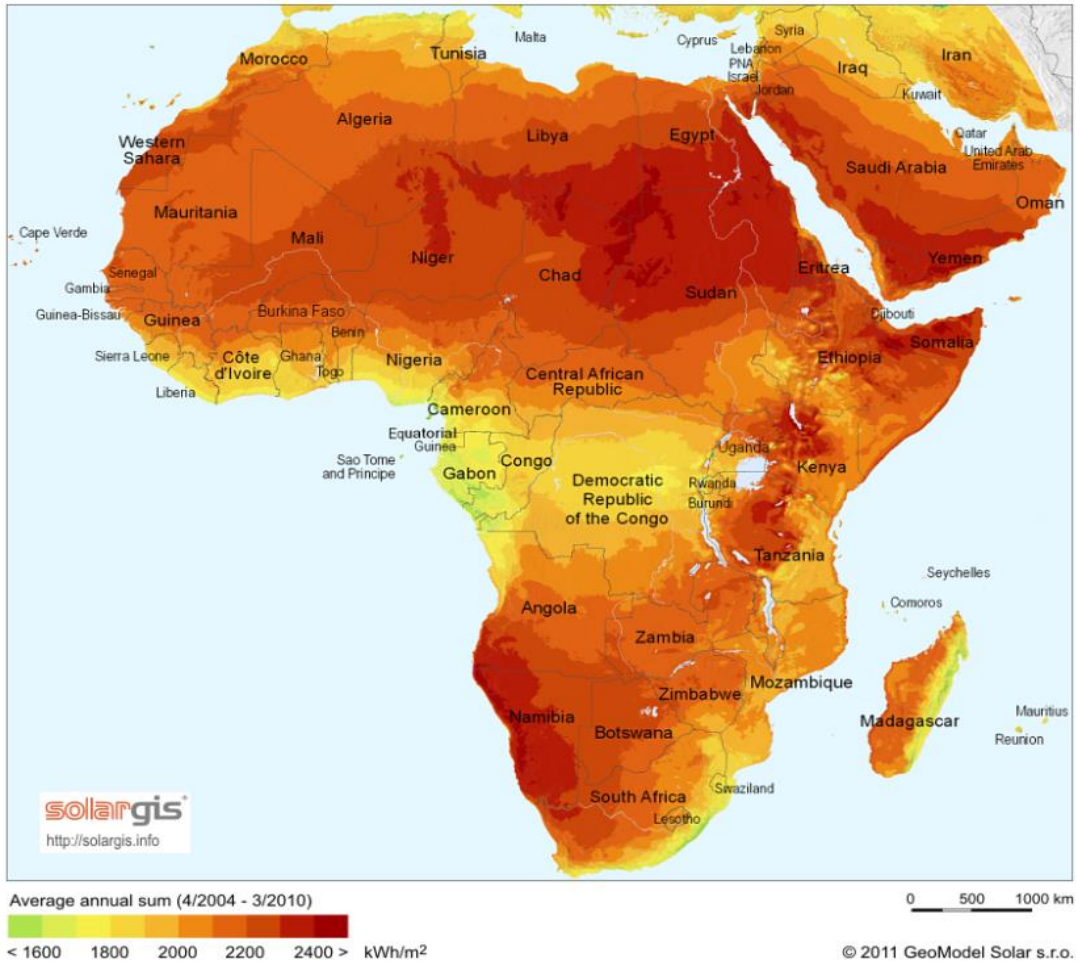


Figure 2.5: Solar irradiation across Africa

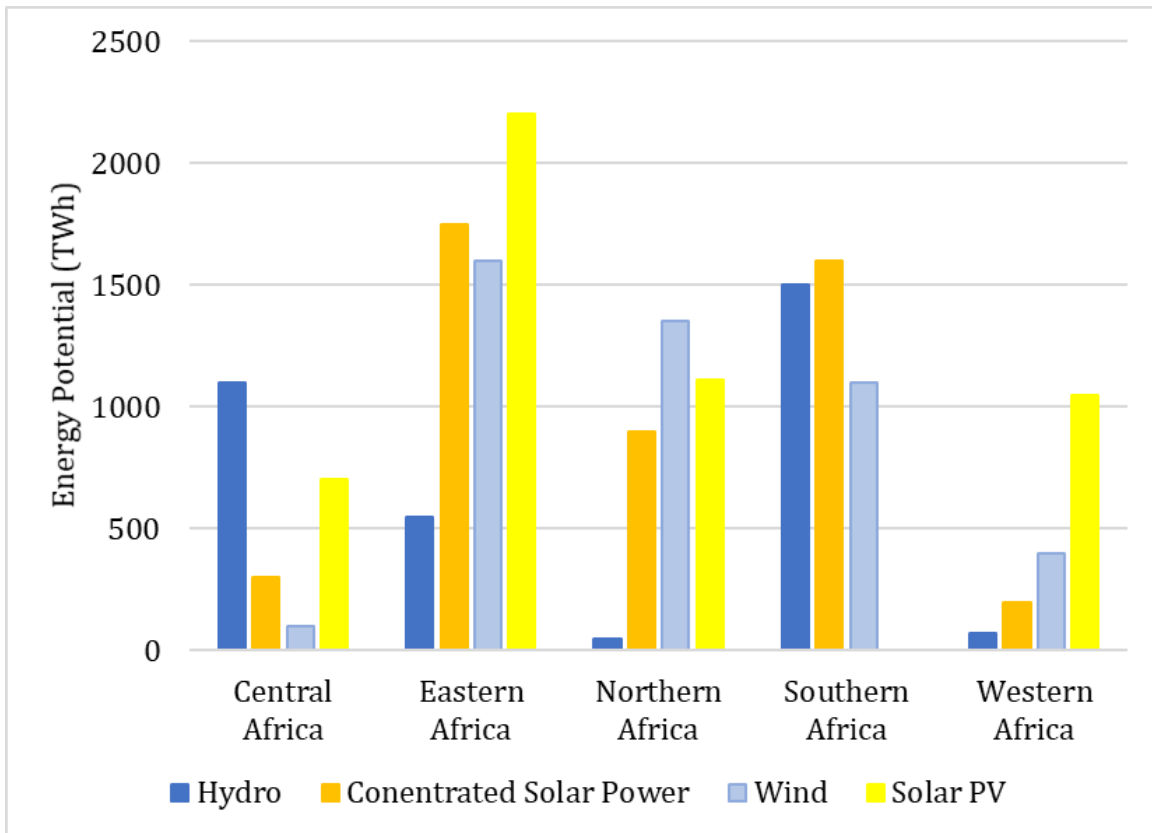


Figure 2.6: Comparison of regional renewable energy potential in Sub-Saharan Africa

Recently, Wu et al. created a Multicriteria Analysis for Planning Renewable Energy (MAPRE) framework that maps and characterizes solar and wind energy zones in 21 countries in the Southern African Power Pool (SAPP) and the East Africa Power Pool (EAPP), and enable strategic siting of renewable energy development [1]. The study finds that renewable energy potential is several times greater than demand in many countries, and significant fractions of demand can be quickly served with renewable energy zones that are highly accessible. MAPRE gives the ability to weigh and examine the tradeoffs of multiple siting criteria such as generation cost, distance to transmission lines and load centers, and environmental impact [1]. Successful development of available renewable energy potential requires addressing challenges in siting of these resources. Wu et al. [1] also found that land-use, population displacement, and transmission system extension are essential criteria for renewable energy siting. Due to the spatial heterogeneity of Southern and Eastern Africa's solar and wind resources, strategic siting, regional interconnections, and international energy trade could enable Africa to benefit from solar and wind development that is cost-competitive and low in environmental impact. Successfully exploiting sub-Saharan Africa's renewable energy resources will demand systems integration and strategic planning due to this uneven distribution of high-quality solar and wind energy resources. Potential synergies that can be explored are dual land use strategies and co-location of generation plants. Dual land-use strategies, such as the combination of agricultural land and wind development, will

prevent potential conflicts that come with land access. Wind and solar generation sites can be co-located in order to reduce costs, maximize transmission efficiencies, and minimize ecological impacts.

2.5 Planning Pathways

Conventional electricity planning entails building and operating a grid based on large central generation plants connected to load centers through a transmission grid and distribution lines with radial flows. This paradigm is disrupted by the development and diffusion of modular generation and storage technologies [34]. Electricity planning, as traditionally understood, meant access by national grid extension and off-grid systems as binary and mutually exclusive options. A significant difference in power system planning in Africa compared to the rest of the world is the notion that electricity supply can be provided not only by extension of the central grid but also by off-grid systems. However, Rawn and Louie [35] point out that traditional assumptions and notions of planning that led to developed power systems around the world are challenged in the context of Africa. Instead, electricity access in the region has to be viewed along a quality-of-service continuum, regardless of source and scale of system provision. This continuum acknowledges the different circumstances and realities of electricity consumers. On one end of the continuum is a residential customer user with low demand and a limited ability to pay for electricity using off-grid solar home systems. On the other end are industrial customers that require high-quality, high-reliability electricity, and have the means to pay for a grid connection and backup generators. The key to improving access is for planners to identify solutions to support the development of all these tiers of users and harness the synergies of diversified system scales from the central grid to microgrids to pico-systems. Policies aligning and coordinating on-grid and off-grid energy systems are crucial to harnessing the renewable energy potential of Africa [35].

A new study by Carvallo et al. [34] corroborates this strategy by developing a novel approach to assess the sequencing and pacing of centralized, distributed, and off-grid electrification strategies by employing the Grid and Access Planning (GAP) model. GAP is a capacity expansion model that jointly assesses operation and investment in utility-scale generation, transmission, distribution, and distributed resources. Model results suggest that utilities should design their distribution systems to include distributed energy resources (DER) deployment from the onset. The study finds that the electrification decision point is not whether to supply a given distribution node from centralized or decentralized resources, but rather the relative balance of the capacity of centralized and decentralized modes of supply, including the distribution and transmission grids. Policy makers and utilities should consider that the joint deployment and operation of grid extension and distributed energy resources (mainly storage and solar PV) is more efficient than the individual deployment of one or the other [34].

Capacity expansion modeling is essential for deciding the generation portfolio mix, the role of renewables, and how to extend transmission networks. An electricity capacity expansion

study for the continent carried out by Ouedraogo [3] quantitatively analyzes the current and future status of power generation using the four power pools as units of analysis. The paper focuses on the West African Power Pool (WAPP) which consists of 14 countries, the East African Power Pool (EAPP) and Central African Power Pool (CAPP) which both consists of 10 countries each, and the Southern African Power Pool (SAPP) which consists of 12 countries. The electricity demand forecast shows that demand will increase four folds in EAPP and SAPP with respect to a 2015 baseline. Electricity demand in WAPP and CAPP will increase three folds and five folds respectively. In the reference scenario, the generation supply was determined by incorporating different levels of electrification policies in each power pool. The renewable energy scenario- which assumes a 0.7% annual growth rate in the electrified population, and that all new capacity additions are the deployment of all committed and planned renewable energy resources only - resulted in a significant 44% increase in power generation compared to the reference scenario. Both the reference and renewable energy scenario, however, resulted in insufficient supply to meet demand by 2040. The total demand for electricity in the reference scenario is 2173 TWh while the estimated generation is only 1155 TWh, resulting in 1018 TWh of unmet demand. The renewable energy scenario results in 510 TWh of unmet demand. The implications are that by using the untapped renewable energy resources of the region, the power pools can electrify faster. The study also finds that there are significant benefits to increasing the efficiencies of the supply side of electricity, mainly by improving transmission and distribution losses.

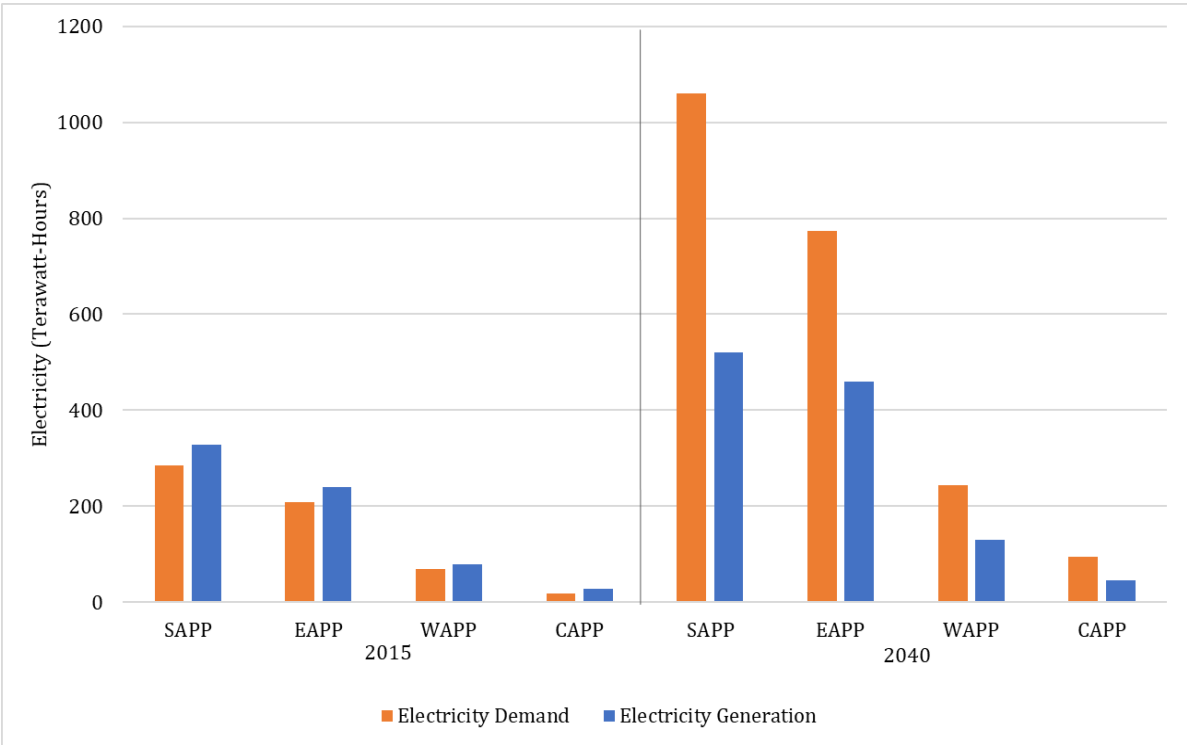


Figure 2.7: Estimated electricity generation and demand growth in the four power pools in Sub-Saharan Africa

In addition to the capacity expansion analysis, Ouedraogo [3] finds that policies promoting an accelerated deployment of renewable energy in Africa need to be designed in such a way that ensures the support of other economic and environmental goals. This finding is consistent with Wu et al. [1] - that a careful selection of renewable energy projects, mainly biomass, is needed to ensure that conservation and biodiversity goals are not disregarded. Selection processes need to account for multiple criteria so that renewable energy development does not exacerbate environmental challenges. Finally, Ouedraogo [3] also supports the findings of Rawn and Louie [35] and Carvallo et al. [34] that more ambitious and innovative electrification measures are required to achieve full electrification of Africa by 2040. Therefore, Africa needs an “all-hands-on-deck” strategy that harnesses both on-grid and off-grid solutions together to electrify the region.

	2015				2040			
Terawatt-hours	SAPP	EAPP	WAPP	CAPP	SAPP	EAPP	WAPP	CAPP
Estimated Generation	329	240	80	29	520	460	130	46
Estimated Demand	286	208	70	19	1061	774	244	95

Figure 2.8: Estimated electricity demand and generation in the four Sub-Saharan Africa power pools using the LEAP model

Carvallo et al. [36] also carry out a capacity expansion analysis to explore low carbon energy pathways for one country – Kenya, as a case study of fast-growing economies in the region. Kenya is unique because of its rich geothermal energy potential, and its transition from one basal renewable resource (hydropower) to another (geothermal). Because of this, the study finds that an externality pricing for CO₂ does not alter the future generation portfolio mix significantly. The study also finds that sensitivity to operational costs due to system degradation has more of an effect on the deployment of geothermal capacity due to its high capital costs. This study also agrees with Wu et al. [1] and Ouedraogo [3] that Kenya, and the region as a whole, will benefit from strategically planned transmission expansions and regional power trade.

Carvallo et al. [36] also create essential knowledge about the need for operational flexibility to support high renewable systems and the role of grid energy storage as an alternative to natural gas and diesel plants for providing flexibility. This substitution has an important impact on system costs as storage enables the adoption of cost-effective renewable resources that otherwise would not be practically adopted.

2.6 Financing Challenges

The electricity challenges in the region, particularly in Sub-Saharan Africa are due to chronic underinvestment in new infrastructure and poor maintenance of existing infrastructure. Historically, publicly owned electric utilities funded the deployment of power system infrastructure. However today, most African governments are unable to fund their power needs fully, and most utilities do not have investment-grade ratings and therefore cannot raise sufficient debt at affordable interest rates. Power investments in Sub-Saharan Africa between 1990 and 2013 were subpar compared to the rest of the continent. Approximately \$45.6 billion was invested in electric power generation in Sub-Saharan Africa between 1990 and 2013. Without South Africa, this estimate is \$31.3 billion [22], [24]. Schwerhoff and Sy [19] review the literature for estimates on the power sector investment requirement in Africa and found ranges from \$41 to \$43 billion per year based on calculations by the African Development Bank, United Nations, and the World Bank. They also find that current spending is estimated to be at \$11.6 billion and an additional \$8.2 billion could be mobilized by addressing utility inefficiencies, the underpricing of power and poor budget execution. This scale of spending leaves an annual funding gap of \$21 billion [19].

Improved power sector investment in the region has come in the form of Independent Power Projects (IPPs). IPPs are power projects that are (mainly) privately developed, constructed, operated and owned. IPPs have a significant proportion of private finance and have long-term power purchase agreements with a utility or another off-taker. Independent Power Projects (IPPs) are the fastest-growing sources of finance and generation capacity in Sub-Saharan Africa [23], [37], [38]. As of 2016, 18 sub-Saharan countries had IPPs, with a cumulative capacity of about 7 GW. These IPPs range in size up to about 600 MW. The overwhelming majority of IPPs are thermal (82%), and the rest are renewable energy [23].

Eberhard et al. [24] identify the key characteristics of a country that enable private sector investment and IPPs and also outline vital policy lessons. In order to attract private investment for IPPs, Eberhard et al. [24] find that there are several critical factors for success ranging from credit enhancement and risk mitigation; competitive and transparent procurement; adequate resource planning capacity; to independent regulation. Eberhard et al. argue that IPPs thrive in countries with strong planning, procurement, contracting and regulatory capacity. The study also finds that while the separation of state-owned generation companies from the central transmission system provides a level playing field for IPPs and more investment certainty and confidence, full wholesale or retail competition is not a precondition for private investment. Instead, clear policy and effective regulatory frameworks are important for securing market entry and fostering enabling environments for private investment.

Financing renewable energy is a high capital cost investment because renewable systems are capital intensive despite their low operating costs. This is in contrast to fossil fuel systems that have comparatively lower capital costs but higher operating costs due to the cost of fuels [19]. Schmidt [39] found that the life-cycle costs of capital-intensive renewable

energy technologies are much more sensitive to increases in financing costs and investment risks than fossil fuel technologies which are less capital intensive. This means that higher investment risks, as is the case in Africa, decrease the competitiveness of renewables compared to fossil fuel systems. This risk sensitivity that hinders initial capital investment shrouds the inherent advantage renewable systems have by being immune to risks associated with fuel and operating cost uncertainties. In addition to investment risks, Schwerhoff and Sy [19] also found that power sector regulatory risks were significant deterrents to private investments in the region.

The onus, therefore, falls on African governments need improved local financing markets and power sector governance thereby decreasing the investment risk profiles of their countries and attracting renewable energy finance. Practical steps for African governments to improve their investment risk profiles include increasing their borrowing, designing viable renewable energy projects that can be funded through direct foreign investment offers, and improving their credit rating through good governance. African governments can also enact national policies and regulatory frameworks that charge polluters for their environmental damage. These measures make it easier for private investors to finance renewable energy projects [19].

2.7 Economic Development and Foreign Investment

While the need and positive impact of international finance in achieving universal electricity access in Africa is well documented in the literature [19], [24], [40], [41], a recent study by Trotter and Abdullah [42] is one of the first to critically analyze the implications of this increase in foreign support for long-term electricity development goals of Africa and Sub-Saharan Africa in particular. Trotter and Abdullah [42] point out that the mechanisms of foreign investment in the electricity sector imply new social, economic and political challenges such as the focus on creating market opportunities for non-African companies rather than domestic companies and the associated risk of increased aid dependency. Increased aid dependency shifts the electrification mandate from African economic development to foreign business interests and produces a foreign dominance in the power sector in Africa, which in turn increases the region's future reliance on foreign assistance. Trotter and Abdullah [42] suggest that these challenges can be addressed by designing context-specific policy interventions, redirecting public funds to rural electrification, and increasing African ownership of power sector expansion projects, to ensure that international assistance is used to make domestic economic development sustainable and more competitive, without leaving the region vulnerable to political change from abroad.

2.8 Energy by Whom?

Beyond the techno-economic challenges outlined above, Africa's energy crisis is also deeply rooted in political and regulatory challenges. Similar to current narratives in the technology

innovation literature, Newel and Bulkeley [43] point out that electrification is not a matter of getting the business model or price right, but about assembling new kinds of social, cultural and political systems. Achieving low carbon energy systems and universal electricity access in Africa will require not only an extensive redesign of the existing energy infrastructure but also a rethinking of energy planning approaches to incorporate social and political considerations. Recently, several papers emphasize the need for electricity planning in Africa to be dynamic and responsive and, most importantly, be able to consider not only the techno-economic factors but also consider the social and equity factors involved when addressing people's energy needs [44]–[48]. If the end goal of electrification is poverty alleviation and sustainable development, then research and policy agendas must recognize the power of energy infrastructure to redistribute social power, entrench social behaviors, and limit the choices available to consumers [49], [50]. The electricity challenges present opportunities to design appropriate infrastructure in such a way that prioritizes equity, justice and lifts Africa out of poverty.

Re-envisioning energy planning is inspired by emergent conceptual lenses in the literature such as energy democracy and energy sovereignty. These movements represent contemporary expressions of an ongoing struggle for increased agency and choice over energy decisions. Broto [44] defines energy sovereignty as the capacity of people to make decisions about their energy planning. Similarly, Burke and Stephens [51] posit that energy democracy advances renewable energy transitions by resisting the fossil-fuel-dominant energy agenda while reclaiming and democratically restructuring energy regimes. According to Burke and Stephens [36], renewable energy, in particular, opens opportunities for democratic energy development.

By integrating the technological change required for low carbon energy systems and universal access with the potential for socio-economic and political change, the energy democracy and energy sovereignty movements links social justice and equity with energy innovation, and offer opportunities for a re-alignment of energy systems and a shift in social and political dynamics [44], [45], [51]–[54]. Policymakers around the world increasingly recognize this need for energy democracy and sovereignty. The United Nations recommended in a policy brief on the sustainable development goals that achieving energy access should be linked to ensuring people's control over energy choices and their capacity to manage their energy [55].

When taken together, energy sovereignty and energy democracy critically raise the question - "energy by whom?" This question is especially pertinent for Africa because of its multi-faceted electricity gap, and the potential for distributed energy innovation to disrupt conventional planning paradigms. As highlighted by Carvallo et al. [34], Rawn and Louie [35], and Trotter [46], Africa – and Sub-Saharan Africa in particular – have unique characteristics that make traditional electricity planning paradigms insufficient. The technological advancements can alleviate electricity poverty in distributed technologies, primarily distributed electricity generation, to empower small-scale actors such as households and communities to autonomously plan for and manage their electricity [56]. Distributed generation technologies offer new ways to plan for electricity, and will transform not only how electricity is provided, but also who plans for it. It moves electricity planning from solely

regional governance to households and community governance as well, re-distributing the agency and decision-making power of achieving a renewable electricity system in Africa, from only in the hands of the utilities to end-users and households as well [57]–[59].

Concepts such as energy democracy and energy sovereignty can shape the roadmaps for designing new planning approaches that enable and encompass the increasing adoption of decentralized generation and decision-making in Africa. For example, Trotter [46] highlights a case of this in the country Ghana. Ghana reversed its high electricity inequality from one of the most severe to one of the lowest in sub-Saharan Africa. Ghana improved from 6% to 50% rural electrification from 1990 to 2014 using participatory approaches in their rural electrification policy design.

A new paradigm to achieve universal access and enable a low-carbon future in Africa will require revolutionary changes in the way electricity provision is thought of and planned for. An understanding of “energy by whom?” in Africa is a critical component of the challenge. The scope of planning for both academics, policymakers and practitioners should expand beyond the technological and economic impacts on energy infrastructure and the climate benefits of renewable energy, to acknowledge and consider the socio-political implications and the potential for a new paradigm to alleviate injustices and burdens borne out of the inadequate electricity planning on the continent so far.

2.9 Conclusion

Africa, Sub-Saharan Africa in particular, is experiencing a persistent, complex and multi-faceted electricity gap. The scale of electricity system expansion needed to achieve full access is unprecedented and requires an inclusive “all-hands-on-deck” strategy in terms of system type – grid and off-grid; in terms of financing mechanisms – private and public investors; and in terms of actors – utility and IPPs stakeholders, regional power pools, off-grid providers, and prosumers. Renewable energy will play a prominent role in meeting Africa’s projected demand growth [1], [3], [13].

The region’s renewable energy potential is greater than its estimated demand, and its deployment can precipitate other co-benefits besides electrification such as education and health sustainable development goals. However, successfully integrating large shares of variable renewable resources will require high grid flexibility, which is currently hindered by the difficulty of operationalizing power pools for regional trade and the high costs of grid-scale energy storage [25].

Power sector expansion will require private sector investment, and the majority of recent capacity growth has come from independent power producers. However, private foreign investment has cautious implications for the successful social and economic development of African countries - the ultimate goal of electrification. Energy planners and policymakers need to ensure that the goal of electrification is regarded together with the goals of national economic development and social welfare.

Altogether, it is critical that the decision-making and research agendas for electrification have an increased focus on understanding the needs of the African people. Electrification strategies must be holistic, adaptive and ensure participatory involvement in order to achieve sustainable and equitable access for all in Africa.

Chapter 3

Nigeria's electricity gap: Analysis of generation expansion pathways

3.1 Introduction

Sub-Saharan Africa, home to more than 950 million people, is the most electricity-poor region in the world. More than 600 million people lack access to electricity, and millions more are connected to an unreliable grid that does not meet their daily energy needs [2]. Nigeria is the most populous nation in Africa, and the seventh most populous in the world [60]. Despite its abundant and diverse energy resources, the country has widespread electricity poverty and its electricity sector is in operational crisis. Only 40% of Nigerians have access to the electricity grid, and only 10% of rural household have grid connections [26], [60], [61]. The average annual consumption in Nigeria is 145 kilowatt hours (kWh) per capita compared to 4230 in South Africa [16]. As of 2017, Nigeria's installed generation capacity was 13 gigawatts (GW)—about 0.07 kW per capita—in stark contrast to wealthier economies that have installed capacities ranging from 1 to 3 kW per capita. Furthermore, only about 55% of the installed capacity is operational due to aging generation plants and poor maintenance [62].

Despite the stalled growth in generation capacity, the electricity demand in Nigeria continues to proliferate. The International Energy Agency (IEA) forecasts the total demand for electricity in Africa to increase at an average rate of 4% a year through 2040. The official policy documents for electricity planning in Nigeria (Vision 20:2020 and Vision 30:30:30) forecasts a demand growth of 115 GW by 2030 [61], [63]. To meet this demand growth, Nigeria will need to significantly expand its generation capacity and make extensive upgrades to the transmission and distribution infrastructure. A lack of systematic planning and investment in Nigeria's power sector has resulted in a high prevalence of self-generation by using off-grid diesel generators. This persistent electricity gap - both a supply-demand mismatch in grid-connected regions and the lack of access in off-grid regions - burdens Nigeria's economic and social development. Closing the electricity gap in Nigeria is a complex challenge with significant implications for how to achieve the continent's electricity access problem as a whole [16].

Nigeria has two primary energy policies - Vision 20:2020, which was updated in 2016 to Vision 30:30:30. Nigeria's persistent electricity crisis and its energy policies have been explored in the literature. Usman et al. [64] examines the country's energy potential and

reviews the power sector reforms adopted by the Nigerian government in Vision 20:2020. Monyei et al. [60] carries out a systematic literature review of Nigeria’s energy poverty and outlines policy recommendations off-grid electrification. Gujba et al. [61] provide a life-cycle comparison of power generation alternatives to Vision 20:2020. Aliyu et al. [63] also analyses Nigeria’s electricity crisis and uses the Long-range Energy Alternative and Planning (LEAP) tool to assess the cost and environmental impact of Nigeria’s expansion plans in Vision 20:2020. There has been no technical assessment of the Vision 30:30:30 plan and this chapter attempts to fill this gap. I provide an updated review of Nigeria’s electricity sector using academic and practitioner literature. I also develop a first-order generation capacity expansion model to analyze Nigeria’s current electricity expansion plans in Vision 30:30:30, explore alternative generation expansion pathways under various planning scenarios and conclude with policy recommendations.

3.2 Overview of Nigeria’s Electricity Sector

Nigeria is on the west coast of Africa with a land size of 923,768 square kilometers. It has a population of about 190 million people, with about 51% in urban areas and has a 3% population growth per year [60], [65]. Nigeria is made up of 36 states and one Federal Capital Territory (FCT) and has abundant renewable and fossil energy potential [64], [66].

Renewable Energy					Fossil Fuels		
Run-of-River Hydropower	Concentrated Solar Power	Solar PV	Biomass	Wind	Crude oil	Coal	Natural gas
3,500 MW	100 TWh	325 TWh	10,000 MW	14,689 MW	325 billion barrels	0.2 billion tons	5 trillion cubic meters

Table 3.1: Nigeria’s renewable and fossil energy potential

The National Electric Power Authority (NEPA) was formed in 1972 and was responsible for the generation, transmission, distribution and sale of electricity in Nigeria. In 2005, the Nigerian government restructured and privatized the power sector through the Electric Power Sector Reform Act (EPSRA). EPSRA eliminated the monopoly of NEPA, and the electricity sector was unbundled and now consists of six generation companies, eleven distribution companies and the Transmission Company of Nigeria (TCN). The government completed the privatization of the generation and distribution companies by 2014 [64]. TCN

has remained a wholly government-owned monopoly and fulfilled the roles of system operator (SO) and market operator (MO) [67]. EPSRA also created the Nigerian Electricity Regulatory Commission (NERC), which determines tariffs, allows private sector participation, and regulates Power Holding Company of Nigeria (PHCN) and Nigerian Independent Power Producers (NIPPs) [60], [64]. NIPPs were introduced as a quick path to encourage private investment in electricity generation. The Nigeria Electricity Bulk Trader (NBET) was also created to act as a broker between the power producers (both generation companies and independent power producers) and distribution companies [60].

3.3 Dimensions of Nigeria's Electricity Gap

The nation's electricity gap is caused by its lack of generation capacity to supply power to grid-connected regions, the absence of the reliable grid infrastructure to deliver power, the lack of maintenance and investment in new generation capacity, and dispersity of population in remote areas to enable grid connection particularly in the Northern region of the country [16], [64].

3.3.1 Lack of diversified fuel mix and unstable supply

Nigeria has an installed electricity capacity of 13 GW, of which 15 % is large hydro, 0.5% small hydro and 84% is natural gas. Only 4 - 7 GW is technically available on average throughout the year [68]. The nation's generation capacity is unreliable, mainly because of its overdependence on natural gas fuels [16], [68]. The pipelines supplying gas to the generation plants are vulnerable to regional conflicts in the Niger Delta, prone to price volatility, and are poorly maintained. Climate change is projected to have a substantial impact on the reliability of the region's hydropower plants due to varied rainfall patterns and prolonged droughts that force extended outages [69]. Table 3.2 shows the current generation portfolio in Nigeria with the estimated operational capacity of each generator as reported by the Nigerian System Operator in January 2018. NERC rations the inadequate supply to the distribution companies using fixed allocation targets shown in Table 3.3.

In January 2018, the entire country lost electricity supply from the grid due to a fire incident that cut off natural gas supply to five stations: Egbin, Olorunsogo, Olorunsogo NIPP, Omotosho, and Omotosho NIPP [70].

I gathered peak and minimum generation data from the Nigerian System Operators to show the outages of generation in the country from 2014 to the present. Figure 3.1 shows the minimum generation recorded by the Nigerian System Operator for an average day each month from April 2014 to February 2018 and highlights periods when the country generated no power due to gas pipeline vulnerability. In 2015, the operational generation capacity in Nigeria was only 3.1 GW. The loss in capacity was attributed to gas pipeline vandalism [64]. Before a fire incident in the first few days of 2018, the grid was generating about 4.4 GW, and

even 5.5 GW in December 2017- a good accomplishment. This incident highlights Nigeria's need to diversify its fuel mix. The government's response to the incident was to cite the near completion of the Escravos-Lagos pipeline as a future solution that would alleviate these vulnerabilities. I propose to show here that a diversified electricity mix is an economically viable option for Nigeria, rather than its gas dependent path.

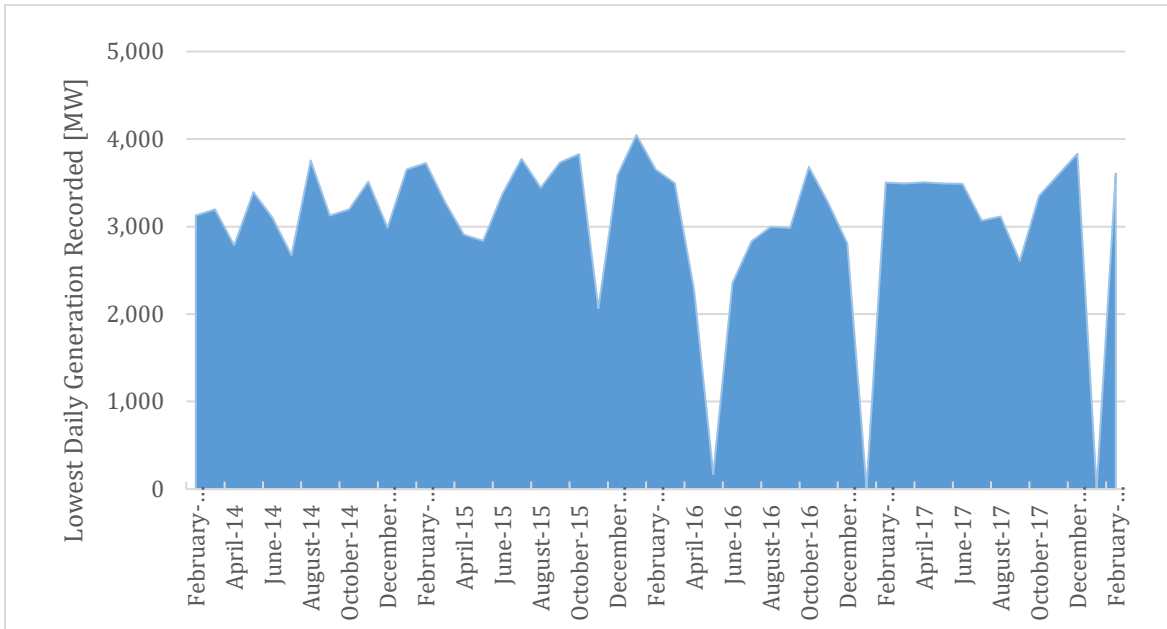


Figure 3.1: The minimum generation on Nigeria's grid from 2014-2018

Generators	Type	Operating Capacity [MW]	Generators	Type	Operating Capacity [MW]
Kainji	Hydropower	440	AES ³	Natural Gas	270
Jebba	Hydropower	382	Okpai	Natural Gas	150
Shiroro	Hydropower	580	Azura	Natural Gas	0
Egbin	Natural Gas	440	Afam VI	Natural Gas	650
Sapele	Natural Gas	0	Omoku	Natural Gas	60
Delta	Natural Gas	615	Geregu NIPP	Natural Gas	290
Afam	Natural Gas	75	Sapele NIPP	Natural Gas	225
Geregu	Natural Gas	300	Olorunsogo NIPP	Natural Gas	290
Omotosho	Natural Gas	336	Omotosho NIPP	Natural Gas	375
Olorunsogo	Natural Gas	336	Odukpani NIPP	Natural Gas	480
Alaoji	Natural Gas	250	Ihovbor NIPP	Natural Gas	337.5
Rivers	Natural Gas	180	Gbarain NIPP	Natural Gas	112.5
Ibom ³	Natural Gas	142			
Total	Hydropower	1,402	Natural Gas		5,914

Table 3.2: Existing generation capacity with estimates of operating capacity as of January 2018

³ As of January 2018, Ibom and AES are non-functional – leaving the available capacity at 6904 MW which was used in the model

Distribution Company	Projected Number of Customers (2018)	Load Allocation %
Abuja	1,065,635	11.5
Benin	1,506,002	9
Enugu	1,061,268	9
Ibadan	2,302,436	13
Jos	629,139	5.5
Kaduna	565,190	8
Kano	787,116	8
Eko	760,781	11
Ikeja	1,493,631	15
Port Harcourt	732,691	6.5
Yola	447,882	3.5

Table 3.3: Load allocation to each distribution company

3.3.2 Debilitated grid infrastructure

There is a significant disparity in the grid's geographic reach - northern states of Nigeria typically have 3-18% of households connected to the grid compared to most states in the south with 40 - 80% households with grid connections [60]. Nigeria's efforts to alleviate its crisis by expanding its electricity generation portfolio will remain ineffective due to the limited capacity of the transmission system – at only 7 GW and about at 30-50% technical losses [60], [71]. The transmission and distribution infrastructure cannot sustain the increasing demand in the country [16], [64], [67]. The transmission and distribution systems need significant operational overhaul and maintenance. The World Bank has recently approved transmission upgrades in Nigeria under its Power Sector Recovery Performance Based Loan program [67]. Nigeria's plan with the World Bank to increase transmission capacity is much needed but will still fall short of its capacity expansion plans to generate and distribute 20 GW by 2020 and 30 GW by 2030.

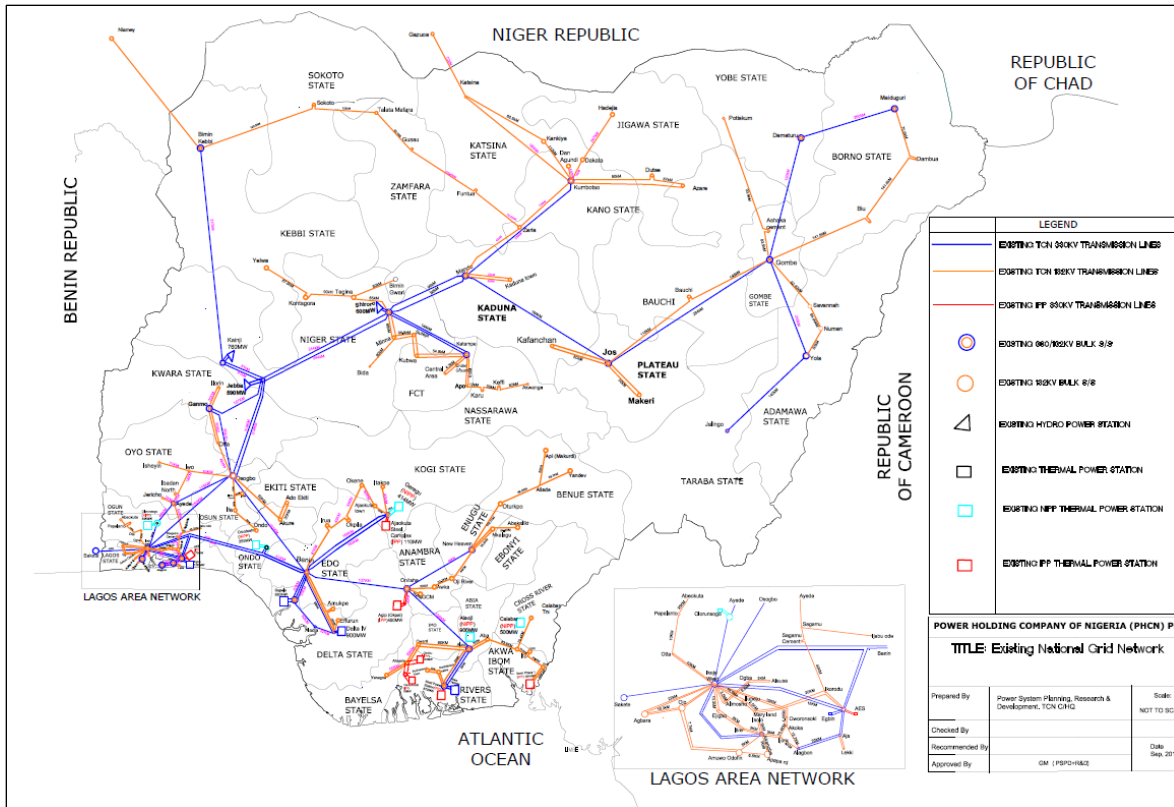


Figure 3.2: Nigeria's electricity network

3.3.3 Dependence on off-grid diesel generation

Nigerian businesses experience an average of 240 hours of power outages per month, and unreliable power supply results in economic losses of more than US\$25 billion annually [67]. The country's inability to provide reliable electricity has led to the prolific growth of inefficient and expensive on-site self-generation in industrial, commercial, and even residential sectors. About 40% of households in Lagos State (South-West Nigeria) have private generators to supplement grid supply, and self-generation capacity estimates range from 6 – 14 GW [60], [67]. Climatescope estimates that self-generation, usually in the form of diesel, meets about 77% of the nation's electricity demand [68]. Self-generation leaves the sector vulnerable to grid defection which reduces the income generation of distribution companies, jeopardizes the companies' financial viability and reduces incentives for further investments in grid upgrades to increase reliability. Most private enterprises are forced to resort to self-generation at a high cost: US\$ 0.20–0.49 per kWh compared to the average grid-based tariff of US\$ 0.09 -0.16 per kWh [16], [26], [60].

Distributed generation capacity (GW)	14 ⁴
Centralized grid generation capacity (GW)	6.9 ⁵
The ratio of distributed to centralized capacity	200%
Levelized cost of distributed generation (\$/kWh)	0.32 - 0.49
Retail cost of centralized generation (\$/kWh)	0.09-0.16

Table 3.4: Comparison of Nigeria's self-generation to its on-grid capacity

3.3.4 Wealth inequality

Nigeria has a high wealth inequality which challenges the electricity sector's availability to design affordable tariffs for all consumer groups. The wealth inequality and customer distrust of metering systems lead to uncollected bills and challenges the financial viability of the distribution companies and the sector in general. It also creates a vast difference in consumer willingness to pay for electricity.

3.3.5 Financial and governance challenges

The power sector is burdened by significant financial challenges due to low tariff collection from consumers, leaving distribution companies with high debt and without enough revenue to pay the generation companies and the gas suppliers. The sector also lacks strong governance measures to ensure the enforcement of regulations and contracts among the various private stakeholders. These financial and governance challenges contribute to the sector's difficulties in attracting private investments, thereby limiting their access to credit and other financing options [22].

These multi-faceted and inter-dependent challenges present opportunities for Nigeria to design diversified and sustainable power systems.

⁴ This represents the average of the estimated range of 8 -14 GW [96].

⁵ This is the current operational generation capacity in Nigeria as of January 2018 according to the Nigerian Electricity System Operator [151].

3.4 Nigeria's Electricity Plans

Demand projections published by the Energy Commission of Nigeria (ECN) assume a 7% annual growth in Gross Domestic Product (GDP) in its reference scenario and estimate about 30,000 MW by 2015 and 115,000 MW by 2030 [61], [63], [72]. ECN also presents high growth and optimistic growth scenarios using 10% and 13% GDP growth rates respectively. However, daily reports from the Nigerian System Operator show an estimated peak demand of only 19,100 MW as of January 2018. IRENA's analysis on the West African Power Pool carried out in 2012 estimates that Nigeria will reach a 20,000 MW peak demand by 2025. I choose the IRENA estimate for all modeling scenarios as the best-case conservative scenario.

Scenario	2020	2025	2030
ECN - Reference growth	45.49	79.80	115.67
ECN - High growth	63.36	103.86	196.88
ECN - Optimistic growth	88.28	170.90	315.11
IRENA	14.98	20.00	24.62

Table 3.5: Nigeria's electricity demand projections

Nigeria published its National Energy Policy (NEP) in 2003 and outlined a master plan for electricity expansion known as Vision 20:20:20 (see Table 3.7). The NEP outlined electricity sector expansion goals to achieve 20 GW of installed capacity and electricity access for 75% of the population by 2020 [72]. However, not only have these expansion targets not been reached, the existing capacity has deteriorated. Vision 20:20:20 also had targets to have non-hydropower renewables as only 2% of total installed capacity by 2030, despite its abundance of renewable energy in the country. The natural gas capacity target was 70% of the mix, like the country's current electricity mix. In 2016, the Nigerian government updated the Vision 20:20:20 to Vision 30:30:30 as part of its National Renewable Energy and Energy Efficiency Policy and its Sustainable Energy for All Action Agenda. Vision 30:30:30 outlines a goal of 32 GW of on-grid electricity by the year 2030 with renewable energy contributing 30% of the generation mix. Vision 30:30:30 also led to the recent signing of 14 power purchase agreements for 1.4 GW of utility-scale solar and a target of 8 GW of small-scale solar.

Renewable Energy Targets	Short Term	Medium Term	Long Term
Solar PV	1400	3000	20000
Wind	20	22	30
Solar Thermal	-	45	6000
Biomass	5	16	50

Table 3.6: Renewable energy targets set by the NEMP with unclear completion dates.

Resource	Existing Capacity in 2003 [MW]	Additional Capacity by 2020 [MW]	Additional Capacity by 2030 [MW]
Natural Gas	4520	9185	1320
Hydropower	1920	4740	5748
Nuclear	0	0	0
Coal	0	388	1320
Solar PV	0	75	425
Wind	0	20	20
Solar Thermal	0	1	20
Biomass	0	5	5
Oil	32	0	0
Nuclear	0	1000	4000
Capacity Addition	0	15414	12858
Cumulative Total	6472	21886	34744

Table 3.7: Nigeria's generation expansion plans (Vision 20:2020)

Due to the challenges in meeting the goals set by the National Energy Policy, the Energy Commission of Nigeria revised it in 2013 and published a new National Energy Master Plan (NEMP) in 2014 with new power expansion targets. The capacity targets for large hydropower were significantly reduced (from 48,000 MW to 6,000 MW) and increased the solar, wind and biomass targets.

Nigeria is not on track to meet any of its expansion targets set out by its Vision 20:2020 or Vision 30:30:30. At the current rate of expansion, even if Nigeria meets its generation expansion targets in Figure 3.3 - which is a generous assumption - millions of Nigeria are nonetheless expected to remain without electricity by 2030. Nigeria's electricity expansion plans will not solve its electricity gap by 2030.

Resource	Installed Capacity by 2020 [MW]	Installed Capacity by 2025 [MW]	Installed Capacity by 2030 [MW]
Solar PV	2000	3500	5000
Wind	170	370	800
Biomass	300	600	1100
Small Hydropower	265	625	1200
Large Hydropower	2540	4000	4700
Coal	424	1408	3200
Natural Gas	4524	7581	13000
Nuclear	0	1000	2000
Solar Thermal	50	600	1000
Capacity Addition	3369	9411	12316
Total	10273	19684	32000

Table 3.8: Nigeria's generation expansion plans (Vision 30:30:30)

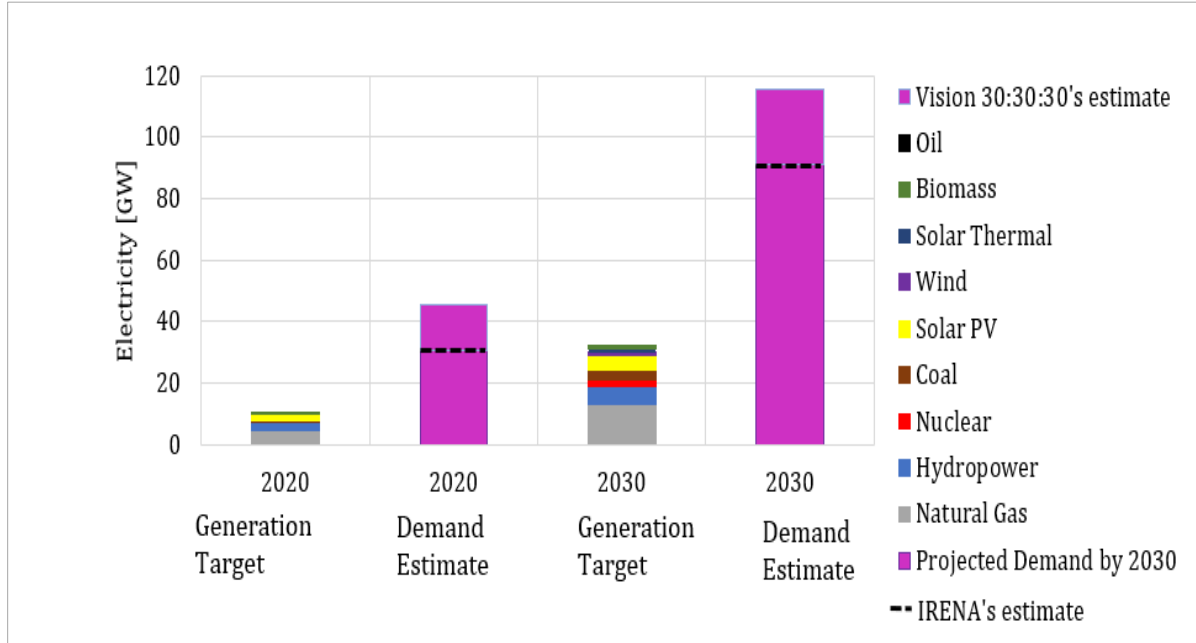


Figure 3.3: Vision 30:30:30's expansion targets compared to demand projections

3.5 Modeling Methods

I build an annual generation optimization model to explore capacity expansion pathways for Nigeria over a planning horizon from 2020 to 2035. The model determines the least-cost generation portfolio from a range of energy technologies to satisfy constraints on load growth, reserve requirements, and environmental concerns. The investment criterion is the linear minimization of the sum of the capital and operational costs of generation subject to constraints that represent stylized operational characteristics of the power system. The model lumps generation plants into resource categories: solar PV, solar thermal, wind, biomass, small and large hydropower, coal, nuclear, natural gas, and diesel. Resource potential constraint ensures that the total capacity installed over the time horizon is less than the resource potential of the region. Load constraint ensures that the annual generation from all resources is adequate to meet annual demand, and the peak demand constraint ensures that there is adequate generation capacity available to meet peak demand plus a capacity reserve margin to account for operational reliability. The model has an annual temporal resolution, so it uses average capacity factors for each generation technology to ensure that it meets annual demand in each year of the planning horizon. The model accounts for the non-dispatchability of some renewables by using a technique that estimates the peak contribution factor of each generation technology. For example, solar generation has a 0% contribution to the peak demand because I assume Nigeria has an evening peak demand when solar generation is not available. Therefore, the peak capacity available is determined by the peak contribution factors, ensuring the capacity value of renewables is not over-

estimated. Other constraints can be added to the model as scenarios to compare to the base case scenario. The model does not include the transmission system. To model Nigeria, I assume that any generation expansion (regardless of fuel choice) will require transmission build-out due to the lack of existing transmission capacity.

The linear optimization with determines the least-cost generation mix is described as:

Objective function - minimizes the investment and operational cost of the electricity generation portfolio needed to meet electricity demand over a chosen time horizon.

Peak constraint - ensures that there is adequate generation capacity available to meet peak demand plus a reserve margin. The peak contribution factors determine the capacity value of each resource.

Load constraint - ensures that the annual generation from all resources is adequate to meet annual demand.

Resource potential constraint - ensures that the total capacity installed over the time horizon is less than the resource potential of the region.

$$\min_{(g)} NPC \left\{ \sum_{g,i} I_{g,i} * (C_{g,i}) + (ep_g + \sum_{g,i} C_{g,i}) * x_{g,i} + \sum_{g,i} O_{g,i} * V_{g,i} \right\}$$

Subject to:

$$\sum_g C_{g,i} * P_g \geq D_i * R$$

$$\sum_g O_{g,i} \geq L_i$$

Figure 3.4: Description of the linear program that determines the least-cost generation capacity expansion.

$NPC()$	The net present cost of the generation portfolio using a discount rate
g	Each generation technology in the portfolio
$C_{g,i}$	The nameplate capacity of each generation technology
i	The annual investment period in the planning horizon
ep_g	The pre-existing generation capacity of each technology
$I_{g,i}$	The capital investment of each generation technology g in period i (per MW)
$x_{g,i}$	The fixed O&M costs of each generation technology g in period i (per MW)
$O_{g,i}$	The electricity generation output of each generation technology g in period i
$V_{g,i}$	The variable costs (fuel and maintenance costs) of each generation technology g in period i (per MWh)
P_g	The peak contribution factor of each generation technology g in period i
D_i	The annual peak demand
R	The planning reserve margin
$O_{g,i}$	The power output of each generation technology g in period i
L_i	The annual electricity load in period i

Table 3.9: Capacity expansion model variables

3.5.1 Data

A table of investment costs used for different generation technologies is in Table 3.10. The costs are amortized over the life of the project into net present costs using the capital recovery factor. I obtained investment cost data for solar PV, wind, biomass, natural gas, solar thermal and nuclear from Lazard Cost of Energy Analysis 2017 [73], and obtained investment cost data for small and large hydropower from NERC's 2012 estimates. I obtained solar thermal and storage costs from the Energy Information Association (EIA) [74]. The levelized cost of electricity is calculated using only the annualized capital costs that occur within the planning horizon.

Resource	Low- High Capital Cost \$/kW		Low-High fixed OM \$/kW-yr		Low - High Variable OM Costs \$/kWh		Life time Yrs	Cap. Factor
Solar PV	1,100	1,375	9	12	0	0	30	0.2
Wind	1,200	1,650	30	40	0	0	20	0.38
Biomass	1,700	4,000	50	50	.02	.04	25	0.63
Small Hydro	3,100	3,300	23	65	0	0	20	0.5
Large Hydro	2,100	2,442	13.7	14.9	0	0	40	0.5
Coal	4,641	5,089	70.7	70.7	.02	.02	40	0.73
Natural Gas Combined Cycle	700	1,300	5.5	6.2	.03	.02	20	0.85
Nuclear	6,500	11,800	135	135	.02	.02	40	0.89
Solar Thermal	3,182	5,050	70	200	0	0	35	0.32
Gas Simple Cycle	750	1,000	5	20	.04	.04	20	0.1
Solar Thermal & Storage	3,800	10,000	75	80	0	0	35	0.43
Diesel/Oil	500	800	10	10	.18	.19	20	0.54

Table 3.10: Lower and upper bound investment costs for new generation capacity in Nigeria - 2018.

3.6 Modeling Scenarios

I begin with Nigeria's current operational generation capacity as of 2018 - 6.9 GW. I conduct two sets of analyses using:

- 1) Vision 30:30:30's generation capacity targets as the peak demand estimates from 2020-2030.
- 2) IRENA's peak demand estimates from 2020-2040.

The first set is designed in a way that allows direct comparison with Vision 30:30:30 annual capacity targets. The model is built to optimize the generation mix using the capacity targets as the peak demand constraint. Vision 30:30:30's outlook ends in 2030. In order to obtain a long-term outlook on Nigeria's generation pathways, and also consider alternative estimates of demand growth, the second set of analysis optimizes the generation mix from 2020 to 2040 using IRENA's peak demand estimates.

The main difference between Vision 30:30:30 and IRENA's estimates is the rate of growth. Both assume that Nigeria will reach 20GW of peak capacity by 2025. Vision 30:30:30 assumes moderate capacity expansion from 2020-2025 (hence moderate peak demand) and assumes a ramp up to 2030. IRENA estimates the 2030 peak demand as 25 GW while Vision 30:30:30 estimates it as 32 GW. It should be noted however that current daily reports from the National Electricity Regulatory Commission already note a grid-based peak demand of 19 GW as of 2018. I acknowledge that there is a lot of discrepancy and uncertainty in demand estimates for Nigeria and I believe that choosing Vision 30:30:30's estimate provides the most meaningful insights on how to reform power sector policies and inform impending investment decisions.

Scenarios	Description
Base Case_Low	Least-cost using the low end of the capital and operating cost ranges
Vision 30:30:30_Low	Vision 30:30:30 plan using the low end of capital and operating cost ranges
Base Case + Storage_Low	Least-cost using the low end of the capital and operating cost ranges and assumes solar thermal is deployed with grid energy storage.
Base Case_High	Least-cost using the high end of the capital and operating cost ranges
Vision 30:30:30_High	Vision 30:30:30 plan using the high end of capital and operating cost ranges
Base Case+ Storage_High	Least-cost using the high end of the capital and operating cost ranges and assumes solar thermal is deployed with grid energy storage.

Table 3.11: Description of modeling scenarios

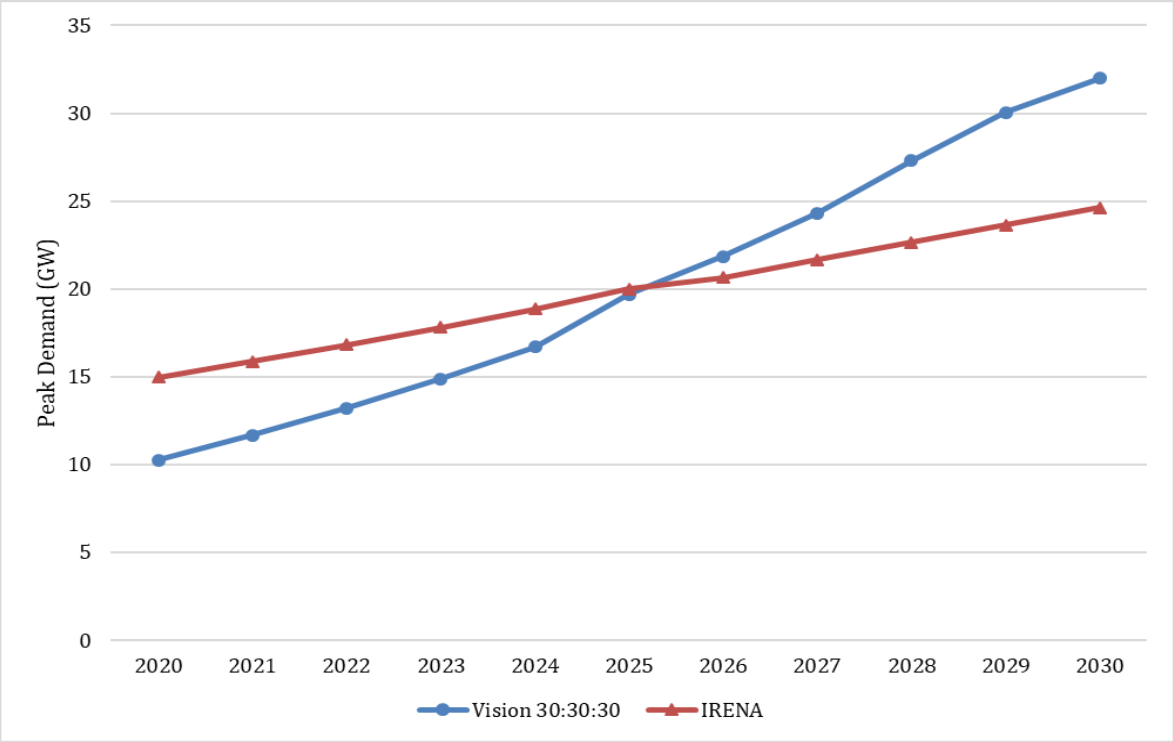


Figure 3.5: Comparison of peak demand estimates from IRENA versus Vision 30:30:30

The results of both sets of analysis should be interpreted as the lower bound of the minimum capacity expansion required for Nigeria to meet grid-connected demand because neither set includes latent demand and demand met by self-generation. The analysis using Vision 30:30:30 peak demand capacity does not account for the high transmission losses that Nigeria experiences. However, the analysis using IRENA peak demand estimates accounts for transmission and distribution losses. Due to the uncertainty and range of investment costs in the literature, I run each set of analysis using lower and upper bound cost estimates. I assume that no significant generation capacity expansion will occur by 2019. I also use a range of discount rates (7%, 10%, and 13%) to explore the impact of the cost of capital on the generation mix. All of the scenario results shown here are run at a 10% discount rate, and the 7-13% sensitivity is discussed.

For each set of analysis, the least-cost scenarios are named “base case,” and no additional model constraints are added to these scenarios. Then the “base case” model is constrained to assume that only the capacity targets in Nigeria’s Vision 30:30:30 plans are installed. Finally, the “base case” scenarios are altered to assume storage is installed with solar thermal technologies.

3.7 Results

3.7.1 Insights from Vision 30:30:30 comparisons

The model results indicate that there are lower cost expansion pathways compared to Nigeria’s Vision 30:30:30 expansion pathway. I assume that one-third of Nigeria’s solar potential can be installed as concentrated solar power with storage, and typically this potential runs out before 2030 in every scenario except Vision 30:30:30. Future analysis could explore higher resolution data on Nigeria’s solar energy potential.

The analysis shows that renewables – solar and wind - are cost competitive and that natural gas can play a role in providing system flexibility, as well as grid energy storage. The analysis also shows that fuel choices should be considered cautiously— mainly Vision 30:30:30’s coal and nuclear targets, which are shown to be more expensive pathways to electrification for Nigeria when compared to the base case. The analysis showed that deploying grid-scale energy storage together with solar thermal plants is cheaper than just deploying solar PV and solar thermal. Deploying solar thermal with storage is cost optimal because storage capacity will provide the needed operational flexibility that a high-renewable penetration grid requires without installing excess gas capacity. Nigeria’s Vision 30:30:30 did not consider energy storage, and therefore underestimates the value of solar energy.

Using a higher cost of capital (13%) has no impact on the generation mix for scenarios using the lower bound of costs. It reduced the solar PV capacity by 2 GW in the Base Case_High scenario. Lower cost of capital (7%) has no impact on the generation mix for any of the scenarios.

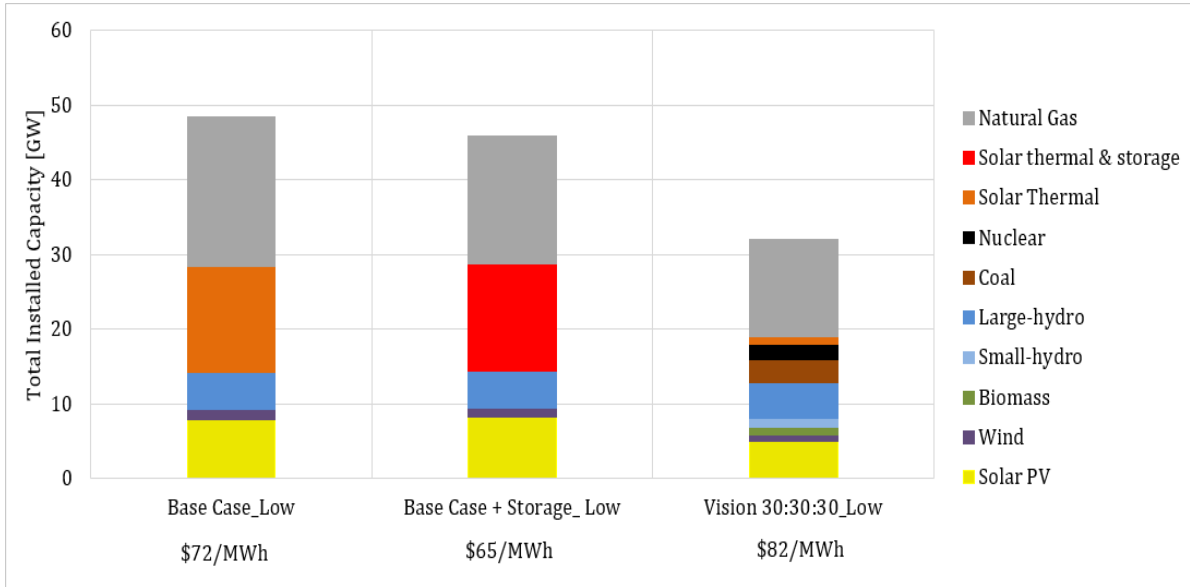


Figure 3.6: Total installed capacity of each expansion pathway using the lower bound of capital and operating costs.

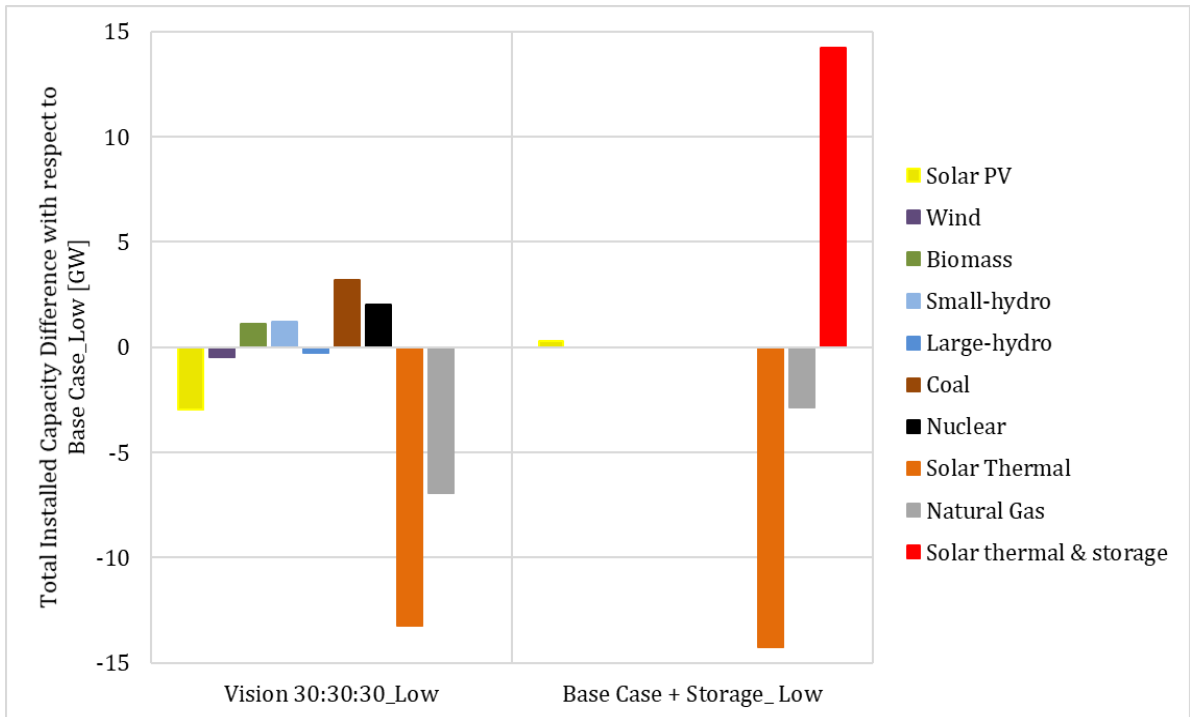


Figure 3.7: The difference in installed capacity of “Vision 30:30:30_Low” and “Base Case +Storage_Low” compared to “Base Case_Low.”

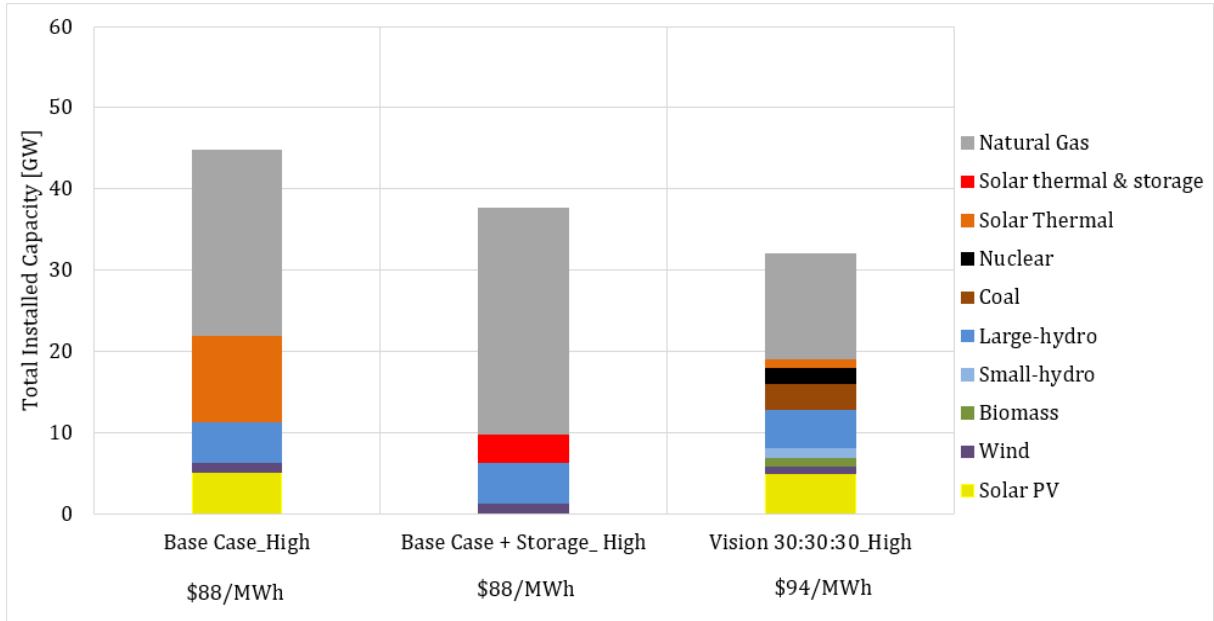


Figure 3.8: Total installed capacity of each expansion pathway using the upper bound of capital and operating costs.

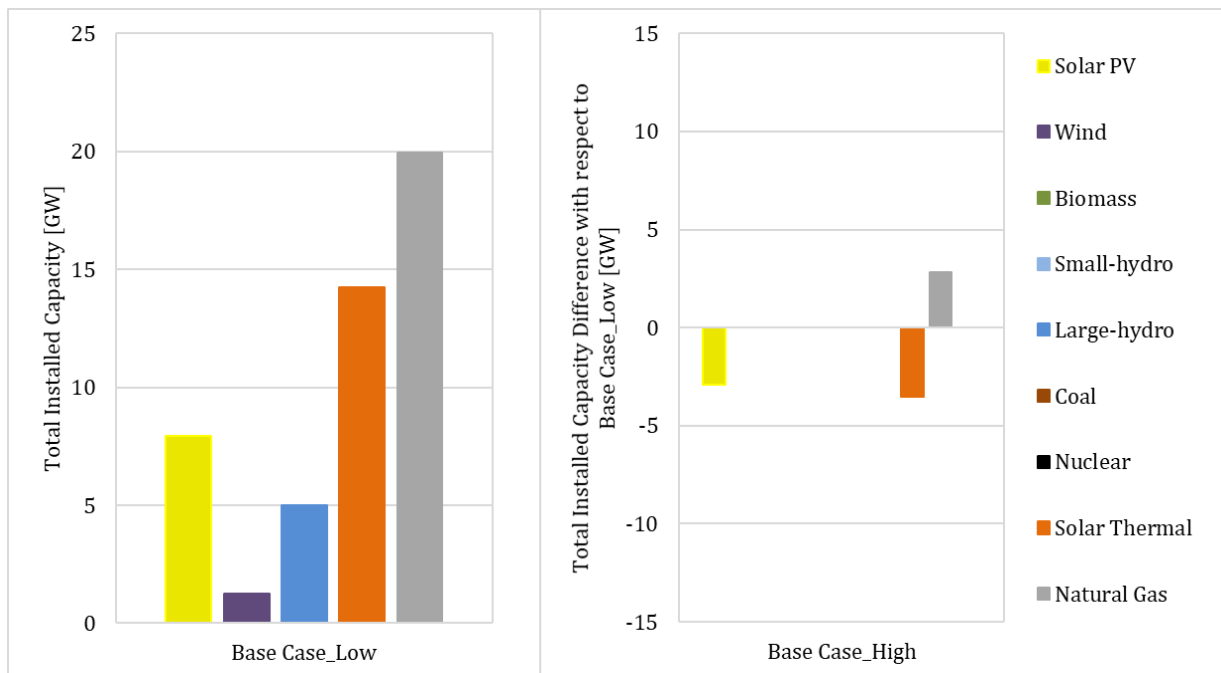


Figure 3.9: The difference in installed capacity of “Base Case_High” compared to “Base Case_Low.”

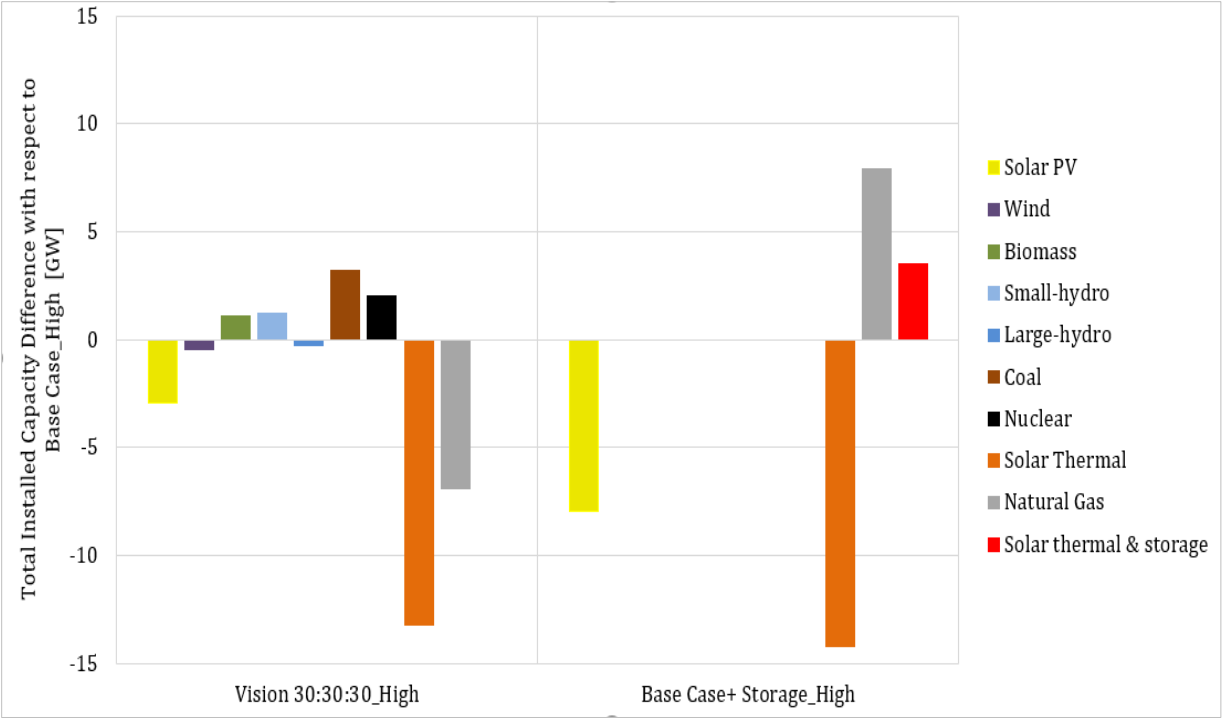


Figure 3.10: The difference in installed capacity of “Vision 30:30:30_High” and “Base Case +Storage_High” compared to “Base Case_High.”

(GW)	_Low (using lower bound of costs)			_High (using higher bound of costs)		
	Base Case	Vision 30:30:30	Base Case + Storage	Base Case	Vision 30:30:30	Base Case+ Storage
Solar PV	8	5	8	5	5	0
Wind	1	1	1	1	1	1
Biomass	0	1	0	0	1	0
Small-hydro	0	1	0	0	1	0
Large-hydro	5	5	5	5	5	5
Coal	0	3	0	0	3	0
Combined Cycle Gas	19	13	16	21	13	26
Nuclear	0	2	0	0	2	0
Solar Thermal	14	1	0	11	1	0
Simple Cycle Gas	1	0	1	1	0	1
Solar thermal & storage	0	0	14	0	0	3
Total Installed Capacity	48	32	46	45	32	38

Table 3.12: The installed capacity of each resource for each modeling scenario.

Resource	_Low (using lower bound of costs)			_High (using higher bound of costs)		
	Base Case	Vision 30:30:30	Base Case + Storage	Base Case	Vision 30:30:30	Base Case+ Storage
Solar PV	16%	16%	18%	11%	16%	0%
Wind	3%	3%	3%	3%	3%	3%
Biomass	0%	3%	0%	0%	3%	0%
Small-hydro	0%	4%	0%	0%	4%	0%
Large-hydro	10%	15%	11%	11%	15%	13%
Coal	0%	10%	0%	0%	10%	0%
Combined Cycle Gas	38%	41%	34%	48%	41%	70%
Nuclear	0%	6%	0%	0%	6%	0%
Solar Thermal	29%	3%	0%	24%	3%	0%
Simple Cycle Gas	3%	0%	3%	3%	0%	4%
Solar thermal & storage	0%	0%	31%	0%	0%	9%

Table 3.13: The percent mix of each resource for each modeling scenario.

3.7.2 Long-term outlook using IRENA's forecasts

Applying IRENA's peak demand estimates till 2040 show similar natural gas deployment as the 2030 outlook but with increased deployment of solar technologies (PV and solar thermal). The upper bound of capital costs did not affect the generation mix and still deployed a significant amount of solar energy. Longer modeling horizon highlights the importance of declining prices on solar and points to the need to reform Vision 30:30:30 to reflect changes in technology costs and innovation.

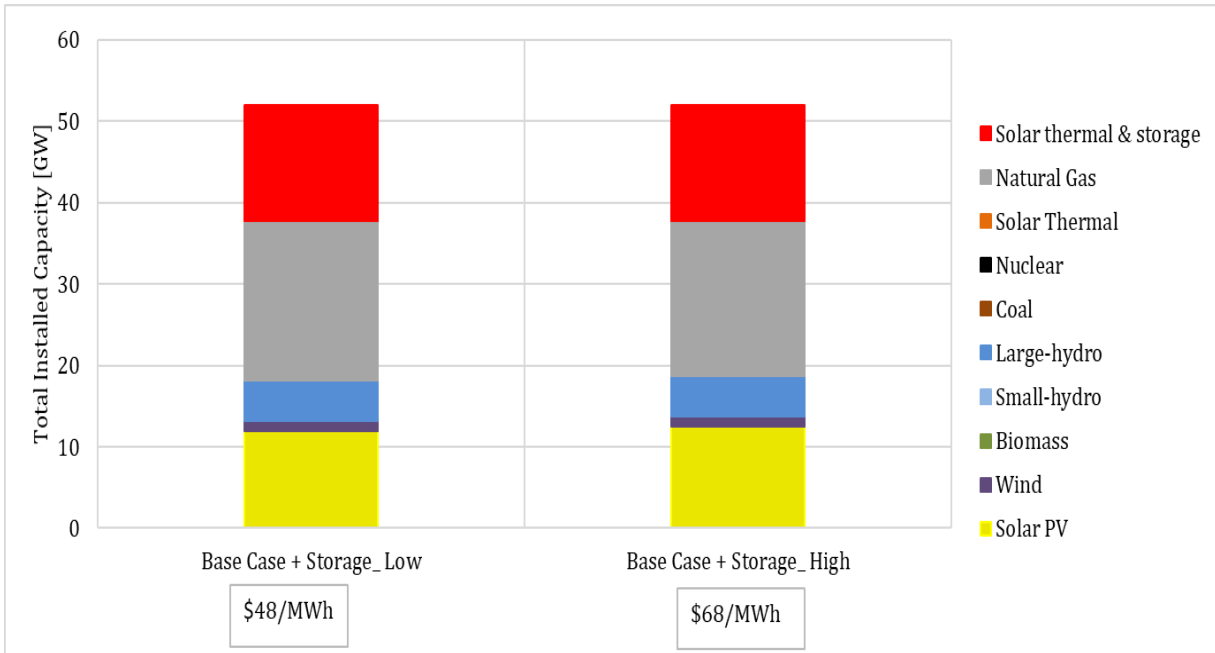


Figure 3.11: The installed capacity in 2040 using the IRENA demand estimate

3.8 Policy Recommendations

The modeling scenarios highlight two critical policy recommendations about Nigeria’s generation expansion options.

3.8.1 Supply diversification

This analysis shows that Nigeria should aim for at least a 40% share of non-hydropower renewables in its on-grid generation mix by 2030, and aim for as much as 50% by 2040. Figure 3.12 and Figure 3.13 compare Nigeria’s current status and its Vision 30:30:30 to cost-optimized pathways in 2030 and 2040.

Nigeria’s electricity system is heavily dependent on natural gas, and the diversification goal in Vision 30:30:30 is based on coal and nuclear deployment which are not cost-optimal. The current Vice President of Nigeria has cited natural gas expansion as a pathway for recovering the country’s power system [70]. However due to reduced operational management and regional conflicts, the gas supply for electricity is vulnerable and insecure. The gas-dependent pathway of Vision 30:30:30 set Nigeria in the right direction of renewable energy adoption but does it sufficiently address the insecurity of pipeline supply to the generator plants, nor address the competition of the generation plants with the international gas markets. The analysis shows that expanding the generation mix using coal and nuclear development is not the least cost-minimization option available. Conversations around

renewable energy development in Nigeria has encountered some resistance, due to the abundance and availability of its natural gas resources. However, the argument for solar deployment does not need to be based on climate change mitigation alone, but also on improved reliability, improved resilience from the volatility of oil and gas markets and reduced infrastructural vulnerability.

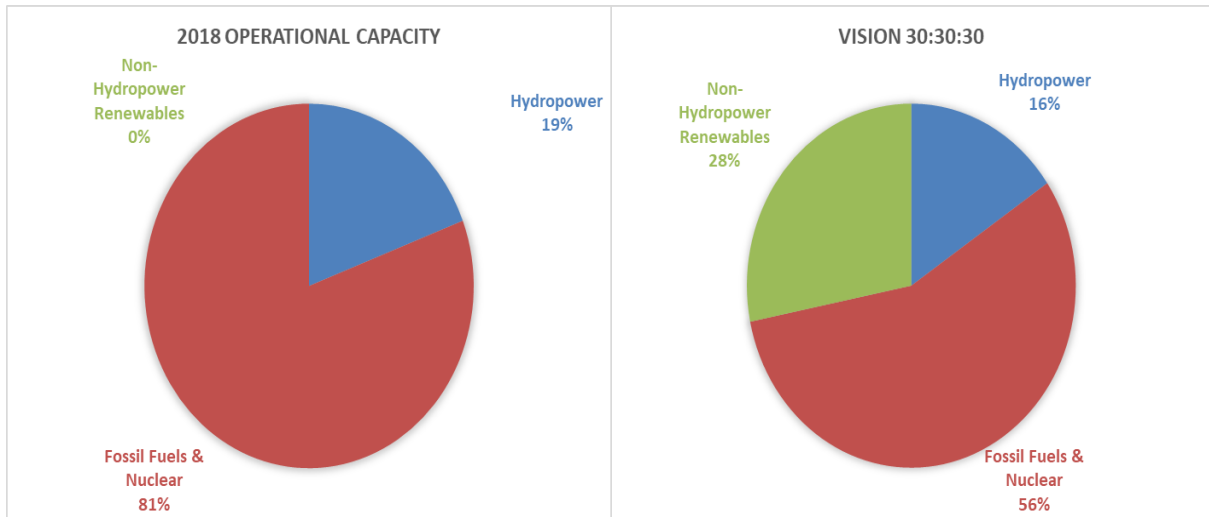


Figure 3.12: Current generation mix (operational plants only in 2018) compared to Vision 30:30:30's generation mix by 2030.

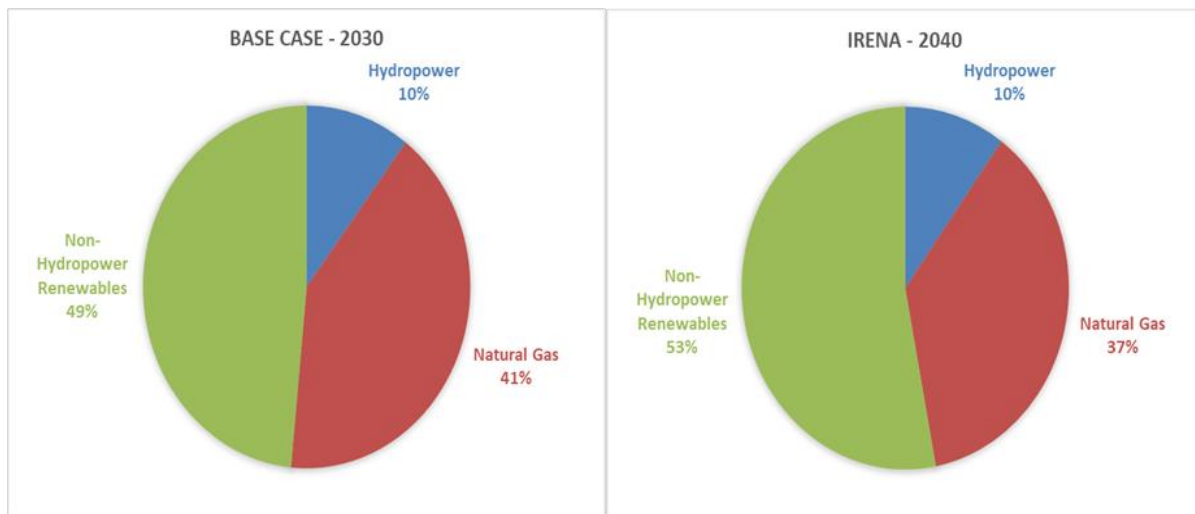


Figure 3.13: Modeled cost-optimized generation mix for the Base Case scenario (ending in 2030) and IRENA (ending in 2040).

3.8.2 The rate of expansion

The rate of expansion required to meet Nigeria's electricity demand growth by 2040 is unprecedented. In 1980, Nigeria had an installed generation capacity of 783 MW for 74 million people (11 MW per capita) [64] and is currently operating about 6900 MW for 186 million people (37 MW per capita). The current capacity represents a small three-fold increase in about 40 years. The average investment in sub-Saharan electricity systems is about US\$8 billion a year [24], [39]. As of 2015, only US \$20 billion had been invested in the Nigerian power sector since 1999 [64]. This rate of investment is inadequate for addressing the existing infrastructure challenge, to expand access and grid coverage, and to meet the rapid growth in demand. Our results show that Nigeria will have to install at least an additional 38 GW by 2040, about six times the current operational capacity, to keep up with grid-based load growth alone.

The rate of centralized capacity expansion needed by 2040 highlights the dire need for distributed solar generation to accelerate the pace of recovery, in both electrified and unelectrified regions in the country. In electrified parts of Nigeria, it will increase reliability because it will reduce strain on the transmission system's limited capacity. In unelectrified regions, distributed solar provides access while investment efforts focus on getting existing infrastructure into operational viability.

Therefore, Nigeria's full electrification (including latent demand and off-grid electrification) will require combining multiple pathways and strategies. Nigeria should create planning synergies between centralized and distributed energy systems to bolster financial support and investments from private investors and improve the sector's institutional capacity and regulatory power.

3.9 Conclusion

This chapter presented an overview and cost analysis of the electricity crisis in Nigeria and highlighted the policy implications. Nigeria will need to expand its electricity sector significantly to meet its current and future demand. The overdependence on natural gas for generation has stifled the country's power system expansion. There is an increasing awareness of environmental issues and political conflicts associated with natural gas production in the Niger Delta region, posing a severe threat to energy security and undermining Nigeria's power sector reform [61]. As shown through the range of scenarios, there are alternative expansion pathways that can enable Nigeria to alleviate its electricity crisis in an economical and environmentally sustainable manner.

This chapter proposes an analytical tool for evaluating the range of options as Nigeria's makes critical power investment decisions. I find that there is a range of technically and economically advantageous capacity expansion pathways that Nigeria can take to meet its short and long-term electricity needs. Vision 30:30:30 sets Nigeria in the right direction of diversifying its energy mix but underplays the role solar energy could play. The critical

consideration is diversification – it is Nigeria’s interests to take advantage of the falling prices of solar energy technologies to reduce its dependence on natural gas fuels for generation. Even though Nigeria is an urgent rush to expand its generation, the government should approach coal and nuclear power development with caution as it is the more expensive path. I propose here that Nigeria needs to review its Vision 30:30:30 energy policy and reassess the role of solar energy in its future energy mix.

Chapter 4

Generation expansion analysis in low data settings

4.1 Background

Two of the significant challenges facing emerging economies today are expanding energy access and alleviating poverty in a carbon-constrained world [75]. There are over 1.1 billion people without access to electricity, located mainly in sub-Saharan Africa despite the regions' abundance of energy resources [36]. The design of sustainable electricity systems needed to fuel regional development in these regions requires context-specific power system modeling. This is increasingly essential particularly in sub-Saharan Africa where the electricity systems are relatively new [36]. Sub-Saharan countries must balance their economic development goals and electricity expansion plans with local and global environmental concerns. Therefore, significant investment decisions are being made today about the electricity grid that needs to be informed by system modeling and analysis. Given the current carbon and resource constraints globally, it is of the utmost importance that analysis on these countries is made possible despite the data access challenges to inform policy on electricity access, technology choices, and climate change. Simple, context-specific and system-reflective models are essential to filling these gaps, enabling many countries to plan effectively and vet possible power expansion pathways [76].

However, only a few studies have focused on national and sub-national power system modeling in sub-Saharan Africa. Sub-Saharan African countries are projected to have significant economic growth in the coming years, and the demand for electricity will increase rapidly [2], [3], [77], [78]. The lack of power system analysis in these countries is partly due to limited data availability and access, and the lack of open-access modeling tools. Because of these challenges, countries with limited data availability and limited access to researchers and scholars may be left unanalyzed. Hence, system planners may lack the insight to guide their grid's development. The desire for high modeling precision that drives the high data requirements of power systems modeling may inadvertently result in these countries being left out of the academic's and practitioner's technical analyses that inform their energy development.

I seek to build a model that balances the goal of having low-resolution data requirements with the goal of providing useful, tenable results. To do this, together with a team, I have successfully designed an open-access generation capacity expansion model - known as PROGRESS (Programmable Resource Optimization for Growth in Renewable Energy and Sustainable Systems) to explore least-cost generation pathways for power systems expansion in low data contexts. PROGRESS improves on existing generation capacity expansion models by reducing the data input requirements significantly. I acknowledge the benefits of high-resolution modeling data and have reviewed studies estimating the

modeling errors due to low-resolution data. Low levels of temporal and technical resolution in power systems modeling could not only lead to an overestimation of the value of baseload and variable renewable technologies, but also result in the underestimation of the value of flexible generation technologies with higher generation costs, and thus a misrepresentation of the reliability of the energy system. Long-term planning models have frequently been applied to analyze scenarios for the evolution of the energy system over multiple decades. Due to computational costs, the level of temporal, technical and spatial resolution in long-term energy models is typically low. In contrast, operational power system models focus on the operations of the power system using a high level of detail and a short-term planning horizon [79]. Resolving computational tradeoffs between these dimensions and bridging the gap between highly detailed operational models and long-term planning models are the main challenges of energy models, especially as variable renewables integration becomes more prominent [76].

I show through comparisons to a high-resolution model SWITCH that the expansion estimation in PROGRESS is reasonable enough to provide a first-order estimation of capacity expansion for countries previously unable to apply existing models. This comparison cannot provide evidence of modeling accuracy, but it at least offers confidence that PROGRESS can be the catalyst for instigating context-specific power systems modeling for previously understudied cases. PROGRESS is easily reproducible and has low computational requirements - its current runtime is 1 – 2 minutes which allows it to do monte-carlo analysis. PROGRESS could be used to instigate better grid data collection and serve as the first building block on further modeling capabilities can be built. PROGRESS could then lead to high-resolution power system studies that inform grid extension priorities, especially in the case of siting utility-scale wind and solar, and decentralized power systems.

This chapter discusses the motivation, design, and development of PROGRESS – in the “plain English” description and the algebraic description. This chapter also outlines the inputs, parameters, and outputs of the model. The case of Kenya is used as an implementation example to compare PROGRESS results to SWITCH. This chapter outlines future development options for the model as well.

4.2 Data Challenges for Energy Modelling

There are three main challenges associated with the data requirements of power system modeling [76], [80]–[82].

- i. Firstly, conventional power system models require large amounts of data to describe the existing power system, the existing and forecasted electricity demand and to enforce the operational reliability and policy constraints. Sometimes, data collection and maintenance are tedious processes where energy researchers must dedicate human and technical resources for data collections tasks. This cost may be inhibitive for countries with developing power grids that may lack the institutional capacity to dedicate resources to these tasks. [76], [82]

- ii. Secondly, there is the challenge of the accessibility of data and modeling tools [13]. Some countries have made considerable effort to record their power systems data, but sometimes the data are not accessible in public to researchers and analysts. Also, only a few power system tools are open-access and do not require proprietary licenses to operate.
- iii. Thirdly, there is the challenge of model transparency and reproducibility. If there is limited or exclusive access to power systems data and the models, the lack of transparency may inhibit public acceptance and stakeholder buy-in of the modeling results, limiting the ability of the research to inform decision-making and policy [80]. These challenges are significant, as the goal of modeling itself is to develop insight and inform decisions.

4.3 Review of Energy Models

Energy and power systems modeling tools are used to gather insight and analysis into electricity supply and demand, the development of grid infrastructure, and investment in generation technologies to determine the economic cost and sometimes the environmental impact [76]. There are generally four modeling categories – energy models that primarily use optimization methods and scenario planning; energy models that primarily use simulation methods and scenario planning; electricity models that use simulation and optimization methods; and qualitative models that use scenarios and mixed methods [76]. Scenario planning is a popular method because it enables modelers to explore future evolutions of energy systems and allows policymakers to input policy goals into models, especially as energy challenges expand beyond affordability and availability challenges [76], [83]–[85].

Model Family	Primary Focus	Examples
Energy system optimization	Normative scenarios	MARKAL, TIMES, MESSAGE, OSeMOSYS
Energy system simulation	Forecasts, predictions	LEAP, NEMS, PRIMES
Power systems and electricity market	Operational decisions, business planning	WASP, PLEXOS, ELMOD, EMCAS
Qualitative and mixed-methods scenarios	Narrative scenarios	Stabilization wedges, Deep decarbonization 2050 pathways

Table 4.1: Categories of energy planning models

Within the power systems and electricity family, there are generally three categories for grid modeling [86]. There is a single node economic model which assumes an unconstrained electrical grid. There is a transshipment model where some nodes or regions are defined, and power transfer is possible and constrained by the net transfer capacity and stylized operational constraints. The transshipment model does not model the physical flow of electricity. Finally, there are direct current (DC) and alternating current (AC) power flow models in which the physical flow of electricity is modeled constrained by Kirchhoff's and Ohm's laws. Here, the active and reactive power flows on the power system are modeled. Therefore, the reactance of the power lines is highly relevant, and both capacitive and inductive behavior of the power lines are considered. Either of these three model categories is used for generation expansion planning whose objective is to determine the best size, investment time and resource type of generation units to be built over a long-term horizon to meet expected demand. Computational capacity and data access usually determine which of these three categories a modeler chooses. Other classifications of energy models mostly differentiate along modeling features and resolution. Modeling resolution can be considered along three dimensions: spatial resolution - describing geographic reach; temporal resolution - describing the balance of supply and demand; and technical resolution - describing the operational characteristics [79], [87], [88].

In balancing the need for high modeling resolution with data challenges and computational costs, I decided to prioritize temporal resolution over spatial and technical resolution in PROGRESS for two primary reasons. Firstly, the temporal resolution appears to have the more substantial impact on modeling results compared to technical resolution. Pfenninger et al. [76] carried out a comparison study comparing a low-resolution energy model (with typical low temporal resolution) with a high-resolution energy model and a unit commitment model, and found that operational costs could be underestimated by 38 - 58%. Secondly, I found - through attempts to build power system models for countries where I had little data access - that temporal resolution is needed mostly for demand profiles and is easier to approximate than other spatial and operational details.

PROGRESS fits within the energy system optimization family though it only models electricity generation using normative scenarios [89]. It is also categorized as a single node model as there is no power transfer or power flow modeled. I chose this model family because the normative scenarios allow modelers to configure alternative systems for comparison to existing systems. The optimization method provides an easy way of enforcing normative scenarios through constraints. PROGRESS can also serve as a simulation model by not enforcing the objective function, making it a flexible modeling tool. The ability to compare scenarios is an essential feature to compensate for the reduced modeling resolution and take advantage of the fast run times and the development of many scenarios without high computational costs.

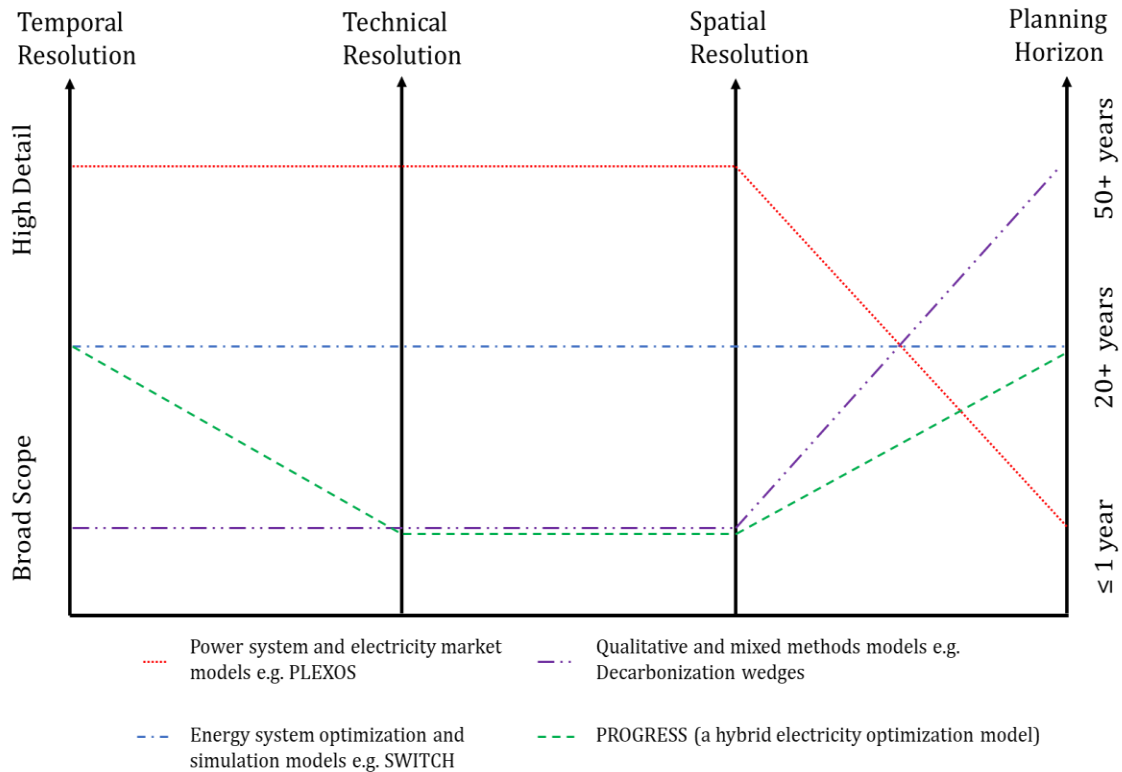


Figure 4.1: Typology of energy systems models and modeling resolutions

4.4 Plain English Description

PROGRESS does not include production cost modeling or unit commitment capabilities. It also does not model the electrical and capacity properties of the transmission and distribution networks. The hourly temporal resolution of load, solar and wind data allows PROGRESS to account for the variability of wind and solar energy production and captures possible correlations between electricity demand and renewable energy production [80], [89]. It has relatively low geo-spatial resolution and assumes a country is a single load node, a trade-off that permits reasonable estimates without large data requirements that would be prohibitive given the state of data availability in some regions with developing power grids. It is relatively easy to have increased geo-spatial resolution if the data is available, by categorizing the country of interest into smaller load areas using grid location. Furthermore, resource availability for each generation technology can also be categorized spatially to incorporate geographic diversity of a country's renewable energy potential.

The PROGRESS model is written in Python version 3 and uses the Pyomo optimization package to define the models cost function, inputs, parameters, constraints, and outputs. The model does not include forecast errors, unit commitment, generator ramping and power

flow constraints. Future work will include monte-carlo capabilities to deal with input uncertainties.

4.4.1 Objective Function

PROGRESS calculates the least net present cost of the generation portfolio given the electricity demand of the region. The generation portfolio is modeled as technologies, not individual generator systems, such as solar PV, wind, biomass, small hydropower, large hydropower, coal, geothermal, natural gas, nuclear and diesel.

The PROGRESS model includes two sets of decision variables: the capacity investment variable and the dispatch variable for each generation technology. Both decisions are made simultaneously not iteratively. The model decides the amount of new generation capacity to install for each generation technology type and assumes that the capacity is available at the beginning of the investment period (equivalent to one year). Then the power output of baseload technologies (coal, nuclear, geothermal and biomass, biogas, cogeneration) and intermittent renewable technologies (solar and wind) generation is specified through capacity investment decision variables. For baseload generators, the power available in each hour is equal to the generator capacity de-rated for forced and scheduled outages (10%). For intermittent generators, the power produced in each hour is equal to the generator capacity multiplied by a capacity factor for that hour that is determined using hourly production profiles. [89] In each sampled hour, the dispatch variable determines the amount of electricity to generate from each technology. This dispatch is constrained to the hourly capacity factor of non-dispatchable renewables including solar, wind, biomass and run-of-river hydropower. The dispatch for hydropower is constrained to equal a monthly budget, but an unconstrained hour to hour. All dispatch decisions are subject to capacity constraints set by investment decision variables.

4.4.2 Operational Constraints

The model has constraints to ensure that the projected demand is met, that there is enough installed capacity to meet a reserve margin and to replicate the operational dispatch characteristics of each technology. *Resource potential constraint* ensures that the total capacity installed over the time horizon is less than the resource potential of the region. On an annual temporal basis, this means that the model limits generation additions to the maximum resource potential of the region. This constraint is particularly crucial for renewable resources such as hydropower, geothermal, solar and wind. Non-renewable resources such as coal and natural gas are either left unconstrained or constrained to its import potential. *Load constraint* ensures that the hourly generation from all resources is adequate to meet hourly demand. Furthermore, the *Reserve margin constraint* ensures that there is adequate generation capacity available to meet the annual peak demand plus a

planning reserve margin (15%). The nameplate capacity of every technology is de-rated by a forced outage factor (assumed to be 10% for every technology).

4.5 Algebraic Description of the Linear Program

$$\min_{(g)} NPC \left\{ \sum_{g,i} I_{g,i} * (C_{g,i}) + (ep_g + \sum_{g,i} C_{g,i}) * x_{g,i} + \sum_{g,i} O_{g,i} * V_{g,i} \right\}$$

Subject to:

$$\sum_g C_{g,i} * P_g \geq D_i * R$$

$$\sum_g O_{g,i} \geq L_i$$

Figure 4.2: Algebraic formulation of the PROGRESS model (designed with hourly resolution)

$NPC ()$	The net present cost of the generation portfolio using a discount rate
g	Each generation technology in the portfolio
$C_{g,i}$	The nameplate capacity of each generation technology
i	The annual investment period in the planning horizon
ep_g	The pre-existing generation capacity of each technology
$I_{g,i}$	The capital investment of each generation technology g in period i (per MW)
$x_{g,i}$	The fixed O&M costs of each generation technology g in period i (per MW)
$O_{g,i}$	The electricity generation output of each generation technology g in period i
$V_{g,i}$	The variable costs (fuel and maintenance costs) of each generation technology g in period i (per MWh)
P_g	The peak contribution factor of each generation technology g in period i
D_i	The annual peak demand
R	The planning reserve margin
$O_{g,i}$	The power output of each generation technology g in period i
L_i	The annual electricity load in period i

Table 4.2: PROGRESS model variables

Objective function: minimize the total cost of generation required to meet load		
Capital investment	$\sum_{g,i} C_{g,i} * (I_{g,i})$	The capital investment I_g for the capacity addition C_g of each generation technology g in each year i . It is calculated as the cost of that resource I_g \$/MW multiplied by the capacity addition C_g for that year i
Fixed O&M costs	$+ (ep_g + \sum_{g,i} C_{g,i}) * x_{g,i}$	The fixed operation and maintenance cost paid for each generation technology g per year is calculated as the total generation capacity of each technology in MW (the pre-existing capacity ep_g plus the capacity addition installed that year C_i) multiplied by the recurring fixed costs of that technology \$/MW-year $x_{g,i}$.
Variable costs	$+ \sum_{g,i} O_{g,i} * V_{g,i} * h$	The variable costs paid for generation technology g operating in year i are calculated as the power output in MWh ($O_{g,i}$) multiplied by the variable costs (sum of maintenance and fuel costs) of that generation technology g and weighted by the sampled hours (h).

Table 4.3: Explanation of PROGRESS' linear program (designed with hourly temporal resolution)

4.6 Data Requirements

PROGRESS requires a set of input variables such as a portfolio of existing and potential resources; projections for operational and capital costs; annual load forecasts and typical load profiles, and the operational features of the different energy technologies such as resource potential and capacity factor for non-dispatchable technologies. Compared to existing models, its data requirements are relatively low and easy to obtain.

One of the significant challenges of undertaking capacity expansion analysis is access to load forecasts and resource potential. PROGRESS requires representative hourly production profiles for solar and wind and run-of-river hydropower, as well as hourly load profiles. National electricity master plans typically report forecasted annual demand but load forecasts, on a daily, monthly or hourly basis may not exist or the data is difficult to access. A typical demand profile with a similar shape can be used and scaled to the annual forecasts found in reports. Renewable resource data is also typically difficult to access. Where this data

is not available for the study region, a profile for a nearby region can be used as an approximation. Descriptions of the model inputs and outputs are in the Appendix.

4.6.1 Time slicing

The hourly resolution for demand is captured using the following sampling method, previously used in studies done in the open access electricity capacity tool known as SWITCH [36], [78], [89]. PROGRESS models each year as an annual investment period. Each year (and investment period) contains a representation of 12 months, two days per month (one peak day and one median day), and six study hours per day. This time slicing method results in 12 months per investment period which represents two days per month and six hours per day. This method gives a total of 144 sampled hours over a year for which the generation system is then dispatched. The peak and median days from each month are sampled to represent a broad range of possible conditions over the course of each investment period [89].

4.6.2 Cost data

The cost associated with each generation technology include capital investment and operating costs. Only the costs incurred during the study period are included in the objective cost function. The capital cost of each generator technology is estimated as overnight capital costs and annualized to the year installed, assuming the generator comes online at the beginning of the same year. The operating costs are estimated as the sum of fixed operational and maintenance cost (O&M) and the variable cost including fuel costs. Cost data is typically reported as in publicly available reports published online by Lazard, as the International Energy Agency and the World Bank. Estimated projections of how these costs will rise and fall over the study period are accounted for in PROGRESS. The cost data does not include grid connection costs, local grid upgrade costs and interest incurred during construction time. The total cost of the generation portfolio is discounted to a present value using a common discount rate (at 10%) that is applied to all technologies.

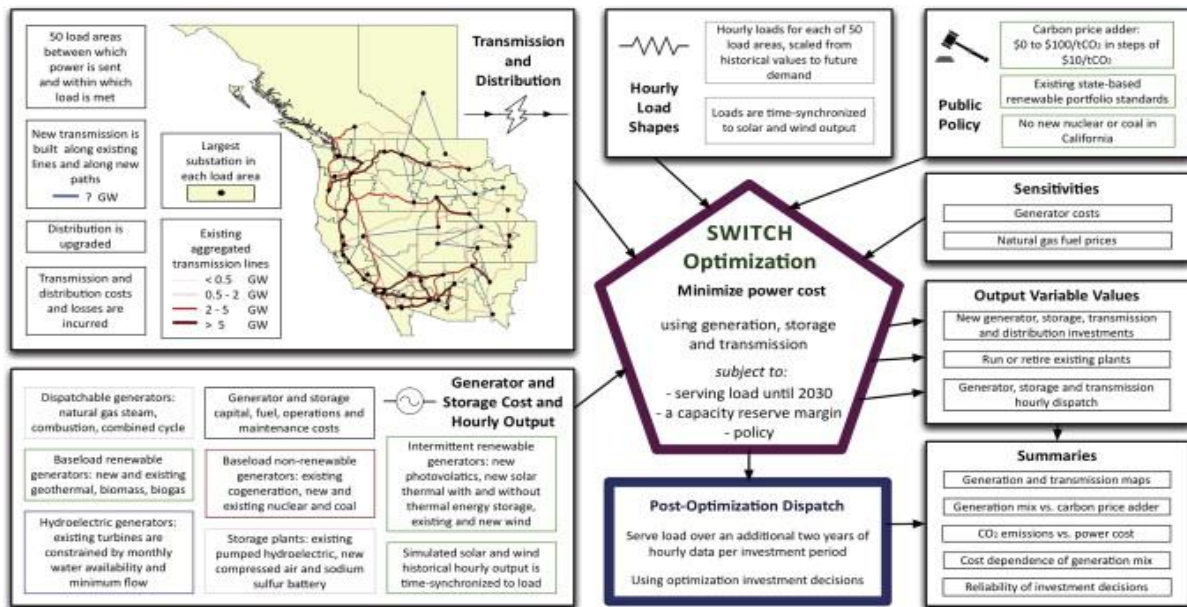


Figure 4.3: Optimization and data framework for the SWITCH model

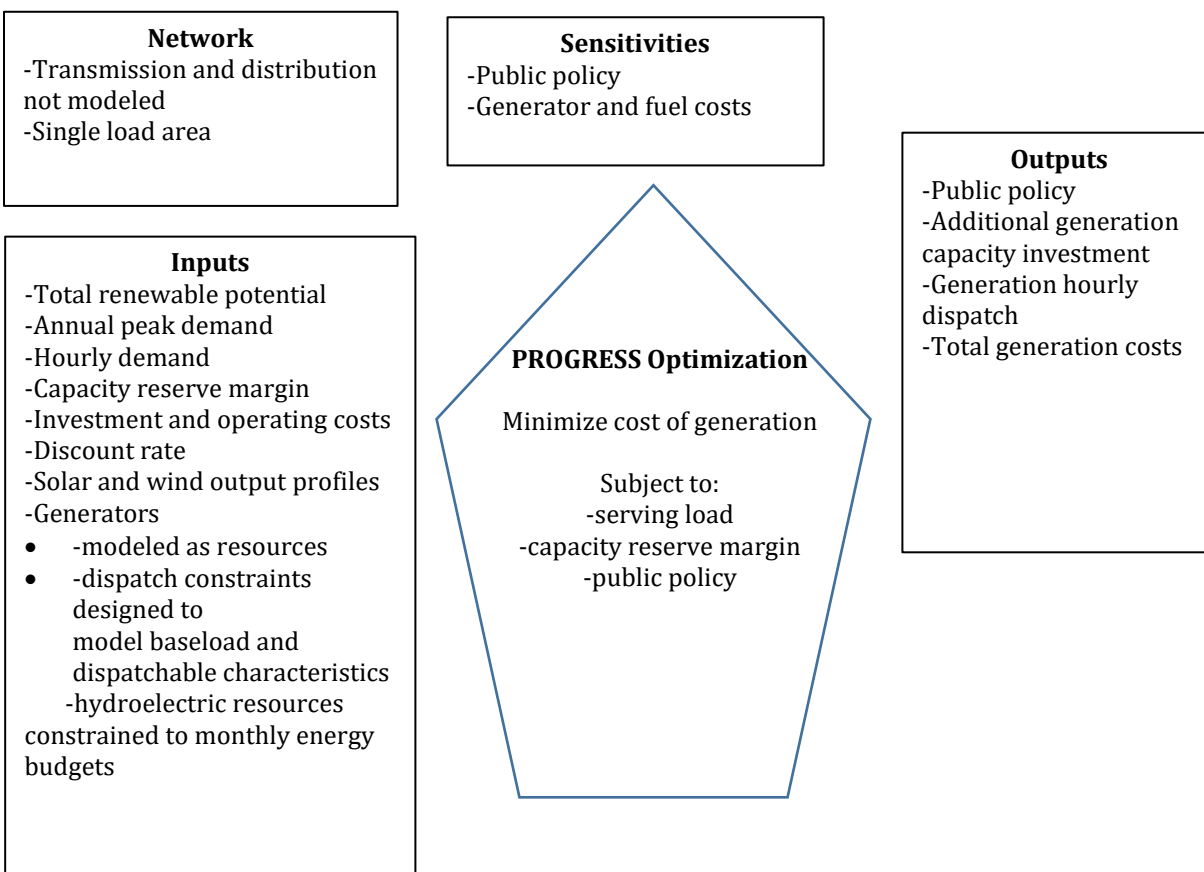


Figure 4.4: Optimization and data framework for the PROGRESS model

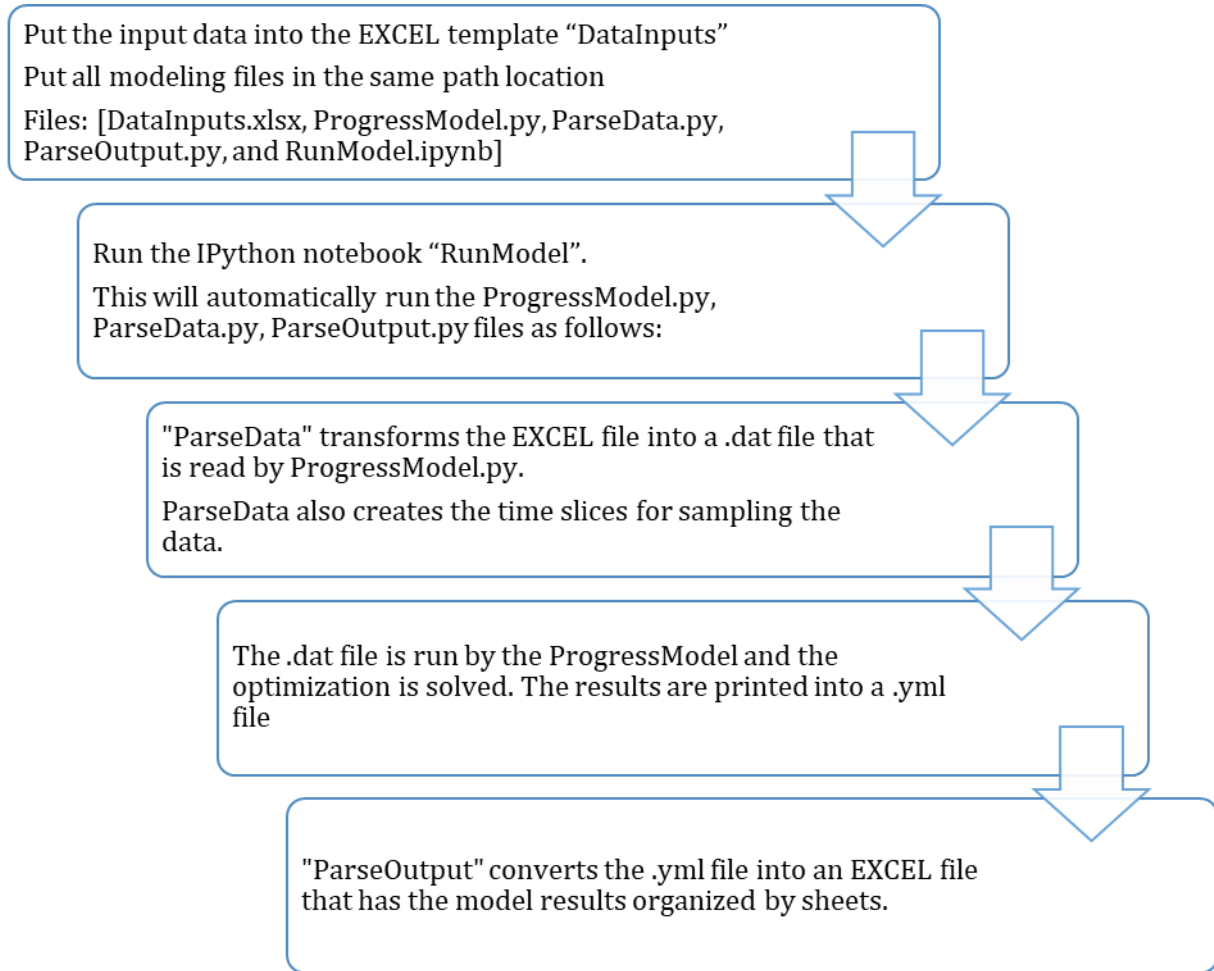


Figure 4.5: The process of running the Progress Model

4.7 Case Study Comparison – Kenya

I chose Kenya as the case study because of its reasonable data access and the possibility of comparison to existing published studies [36]. Kenya is one of the fastest growing economies in sub-Saharan Africa and has electricity expansion plans to fuel its growth rapidly. Only about 50% of its population has reliable electricity access [36]. Kenya has rapidly added generation capacity over the past decade and has a peak grid-based demand of around 1250 MW currently. The national master plans estimate a demand growth of about 8% over the next decade. The installed generation capacity is currently about 2000 MW: 44% hydroelectric, 36% fossil fuels (diesel and natural gas), 22% geothermal, and 0.3% wind power. Kenya has ongoing plans to install about 4500 MW of coal generation in Kitui and Lamu [36]. There is strong resistance from environmental groups and local stakeholders against the adoption of this technology due to environmental and economic concerns [36].

Kenya is well positioned to integrate large amounts of renewables owing to its abundance of geothermal, wind, and hydropower. The cost projections for each resource was obtained from the 2017 Lazard’s levelized cost of energy reports [73].

Resources	Existing Capacity (MW)
Wind	26
Biomass	13
Small-hydro	66
Large-hydro	732
Coal	0
Natural Gas	54
Diesel	645
Geothermal	563
Total	2099

Table 4.4: Existing generation capacity in Kenya

4.7.1 Preliminary results

Initial test runs using the PROGRESS model compared the results of the Kenya case to recently published in the Environmental Science and Technology journal [36]. Although comparing both SWITCH and PROGRESS does not give an apple to apple comparison, it should be noted that the results are generally similar – the comparison is shown in the Appendix.

The analysis in PROGRESS shows that Kenya’s least-cost pathway is also a low-carbon path, with a significant dependence on geothermal, and wind expansion and its existing hydropower capacity providing the needed flexible power to the system. The results also show moderate natural gas expansion. Kenya will need a total installed capacity of about 20 GW by 2035 to keep up with its demand growth.

More importantly, the results show that coal development is not an economically optimal choice in Kenya. Building coal generators now as a stop gap to future transitions to sustainable energy systems may lock Kenya into a sub-optimal expansion pathway that is economically and environmentally expensive. Coal development will likely displace clean energy deployment from resources such as geothermal which operates as a baseload

resource. It could also result in significant environmental and public health risks for local communities in Kenya’s Kitui and Lamu counties [36].

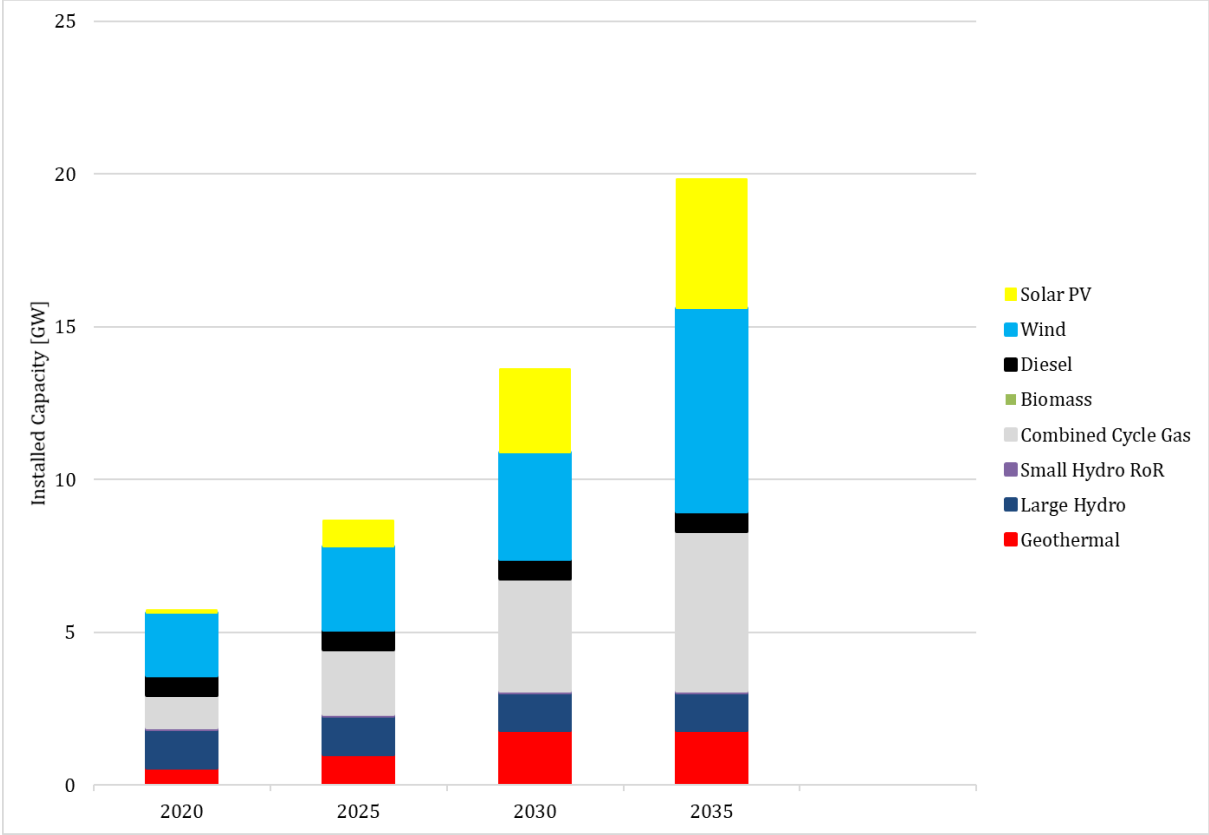


Figure 4.6: The least-cost capacity expansion mix from 2020 to 2035 for Kenya in PROGRESS.

Figure 4.8 shows the hourly dispatch of a typical day in Kenya using SWITCH. Achieving hourly dispatch to preserve high temporal resolution, despite low data access constraints, is a primary goal of this project to ensure that the net load curve is not underestimated [90].

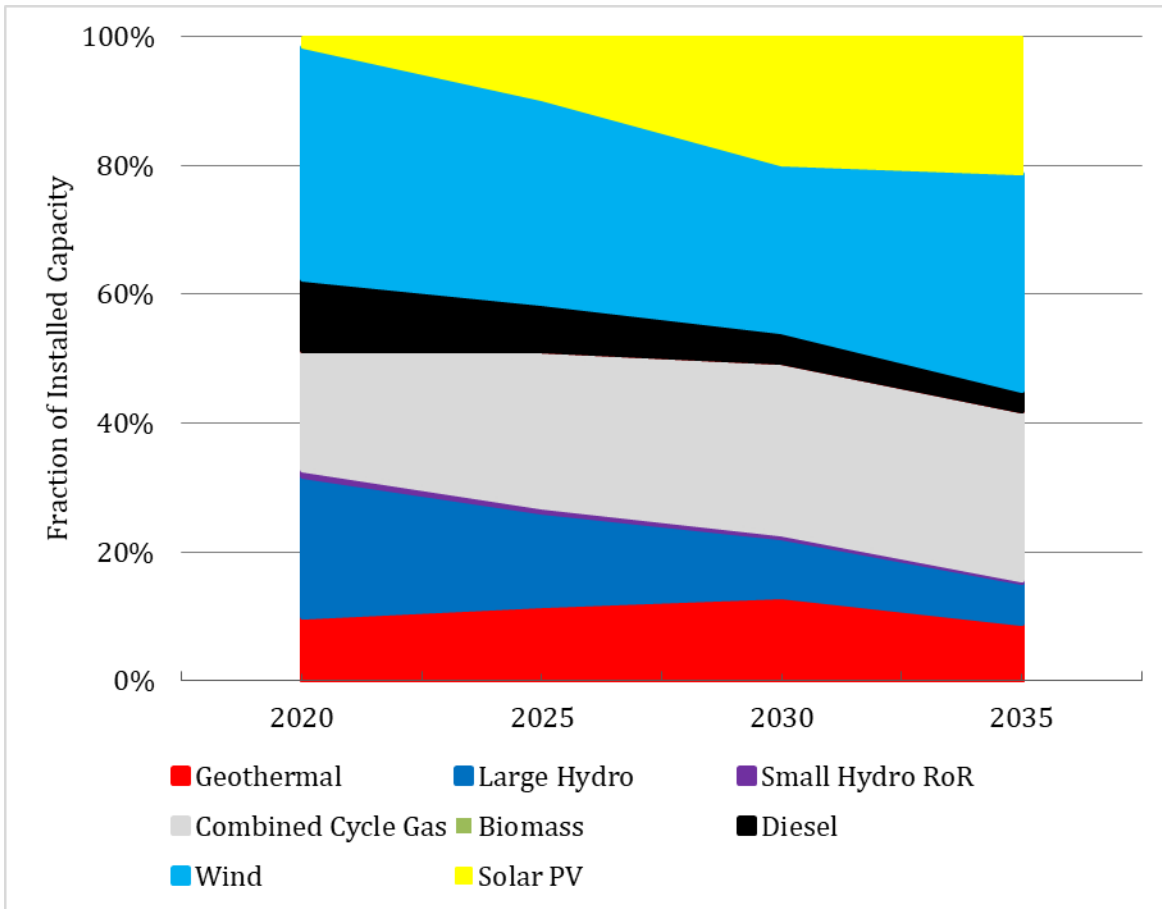


Figure 4.7: The least-cost capacity expansion mix from 2020 to 2035 for Kenya in PROGRESS.

Kenya is well positioned to integrate large amounts of renewables owing to the abundance of hydropower, geothermal and wind. The analysis showed that solar and wind integration does not require one-to-one storage or backup capacity on the grid. Rather, their intermittency can be managed reliably by the overall grid flexibility inherent in the operational characteristics of other resources such as large hydropower and natural gas. There is also the potential for diversification of the nation's electricity mix using solar and wind resources. A diverse electricity mix will lessen the grid's environmental impact, and enable broader power system investments and more significant economic diversity while shielding local communities from the environmental risks of coal generation. Given the abundance of renewable resources in both regions, there is potential to use variable renewable energy to provide baseload capacity by integrating geographically diversified sources and employing the operational flexibility of the existing installed capacity. This ability depends partly on the existing fuel mix of the grid, but because power system in Kenya is relatively young, expansion could be carried out strategically to accommodate large penetrations of variable renewable resources.

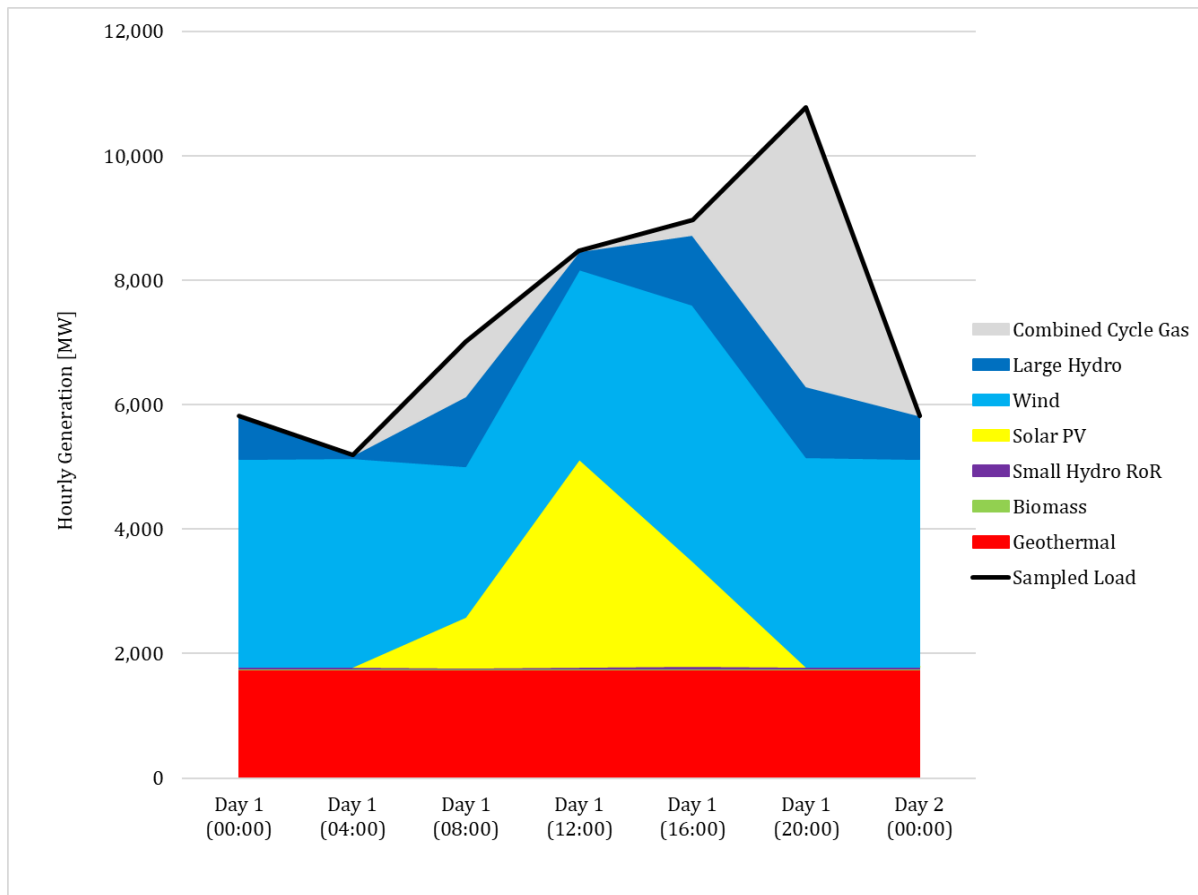


Figure 4.8: The hourly generation on a representative peak day in 2020.

The type of power systems built for coal is different from power systems built for renewables, and deploying coal today may thus determine system characteristics, such as operational flexibility, that may limit the future integration of renewables in the region [36], [91]. Building coal power plants today as a stopgap on the way to transitioning to renewable energy may cause path dependency and lock countries into a suboptimal expansion pathway that is economically and environmentally expensive. This risk exposure is unnecessary because economically feasible renewable alternatives are available in these countries. These case studies show that governments should consider coal development plans carefully and cautiously.

4.8 Future work

Many countries battling with energy and poverty challenges today will eventually be at the forefront of rapid economic and energy development in the coming years. Their investment choices will be critical to ensuring a sustainable future. Simple open-access tools such as

PROGRESS enable system modeling and vetting of possible expansion pathways, thereby providing critical insight to policymakers and other stakeholders.

The development of PROGRESS is ongoing, and only the proof-of-concept stage is presented in this chapter. One immediate goal is to ensure that the PROGRESS model has a good representation of the way electricity generators behave. This will be done by running the model using stress test scenarios to ensure that the power system operations remain reasonable. For example, stress-test scenarios could be designed to check the hourly and annual capacity factors of each resource on under varying demand and weather conditions.

The secondary goal is to use the PROGRESS tool as a platform to run monte-carlo simulations. The current run time of the model for a single scenario is 1-2 minutes. Therefore, a probabilistic dataset could be used to explore the uncertainty bands of the model's inputs and results.

The final goal of the PROGRESS tool is to promote local capacity building among policymakers and other stakeholders. Using Microsoft EXCEL as the input and output interface enables widespread accessibility. It also enables the tool to be used in simple training sessions to non-expert groups on basic power system planning fundamentals. The final goal is to find a way to integrate and host PROGRESS on a webpage with a user-friendly interface. I will explore these ideas and goals next.

4.9 Conclusion

There is significant potential for clean energy to improve electricity access and alleviate poverty in sub-Saharan Africa as shown through the case of Kenya. The choice to invest in fossil fuels, mainly coal, should be approached judiciously to prevent locking in environmentally damaging expansion pathways. Successful integration of high penetrations of variable renewables will require high grid flexibility which can be sourced from existing resources such as large hydropower and potentially from new resources, as grid energy storage as costs decline.

The PROGRESS model allows researchers to understand the cost and policy tradeoffs of different configurations of generation capacity expansion for regions challenged by inadequate access to power system data. It permits an investigation of how capacity expansion targets will perform in the future under various scenarios. It explores how policy decisions and cost projections of technologies may influence the electricity mix of the region. Lack of high quality and high-resolution power systems data is hindering analysis of future grid designs in many countries in Sub-Saharan Africa. The development of planning tools that have relatively low data requirements will allow the vetting of energy projects and their corresponding policies based on their energy, social, and environmental costs and benefits.

Chapter 5

Conceptualizing “Energy by Whom?”

5.1 Introduction

The most daunting challenges facing energy planners today are the decarbonization of energy systems to mitigate climate change, and the provision of reliable, affordable and clean access to over one billion people struggling in the darkness of electricity poverty. A significant obstacle to overcoming these challenges is the dominance of techno-centric approaches to energy planning and policy [48]. Energy planning is inherently socio-technical and is characterized by deep yet subtle interdependences that shape and are shaped by technological, social, political-economic, and cultural processes [92]–[94]. There is natural inertia with electricity systems due to the lifespan of the infrastructure spanning several decades and the various policymaking actors, with diverse and sometimes opposing interests. The sheer scope of the energy industry, its established interests, and its numerous socio-political implications, are just a few of the ingredients in the recipe for entrenched organizational resistance to the transition out of the current paradigm [57], [95]. Envisioning alternative approaches to energy provision will require not only an extensive redesign of the existing electricity infrastructure, but also a disruption of conventional planning approaches and the related institutions, vested political-economic interests, and social values it is enmeshed.

The increasing dominance of energy services being delivered through electricity, and the goal of decarbonization through electrification, necessitates that I focus our analysis on electricity. This chapter explores how distributed generation technologies, particularly the increasing affordability of solar energy, is disrupting traditional electricity provision paradigms. I highlight the growing literature on socio-energy concepts and introduce an emerging concept known as energy sovereignty. Energy sovereignty refers to people’s capacity to make energy planning decisions and seeks to return the control of energy to consumers [44], [53]. I propose that adding energy sovereignty to the pool of socio-energy concepts draws out a crucial question catalyzed by the rise of prosumers: “energy by whom?”. This question is the natural corollary of the existing socio-energy concepts: energy justice, energy democracy, and energy sovereignty.

I draw from a rich literature of socio-energy concepts, focusing on how energy justice, energy democracy, and energy sovereignty can guide planning and policy and lead us into a low carbon energy future. To the best of our knowledge, there is no research that frames the concepts of energy sovereignty with existing socio-energy concepts from an electricity planning perspective. I conceptualize a framework for “energy by whom?” in relation to electricity provision and propose that “energy by whom?” should be adopted as a framework

for reconceptualizing and designing of a low carbon energy future. This question is increasingly important to consider in energy planning due to the paradigm-shifting rise of prosumers.

I situate this chapter in an emerging body of literature that conceptualizes frameworks to integrate the social and human dimension into energy planning approaches. It aims to connect the rise of prosumers due to technological innovation with the long-standing calls for more just, fair and sustainable energy systems. In doing so, it highlights a novel and increasingly important consideration: “energy by whom?” and argues that is an essential consideration for re-envisioning a new energy paradigm and designing a low-carbon energy future.

5.2 Methods

I draw from non-academic and academic literature to build a conceptual review of the concepts: energy justice, energy democracy, and energy sovereignty. I present two examples of increased prosumer action in the Global North and the Global South. Nigeria and California are estimated to have the largest amount of distributed electricity generation in sub-Saharan Africa [96] and in the United States respectively [97]. I chose Nigeria and California to illustrate diverse expressions of increased individual agency in electricity provision energy sovereignty at different stages of electricity development [98], at 58% and 100% electricity access rates respectively. Using this as a foundation, I synthesized a multi-dimensional framework expanding socio-energy considerations in energy planning. This framework can be applied as both a descriptive tool for understanding who plans for electricity and combined with energy justice, energy democracy, and energy sovereignty, can be used as a prescriptive tool for guiding equitable decision making.

This chapter first sets out with exploring the rise of the prosumers and distributed energy technological innovation acting as a catalyst for long-standing social struggles over energy systems. It then situates energy justice, energy democracy, and energy sovereignty under the socio-energy systems framework in order to find commonality and a guiding tenet that can inform planning approaches. It then goes on to propose an additional question –“energy by whom?” - as an essential consideration for designing a low carbon energy future. Finally, it draws out overall conclusions about thinking about socio-energy challenges and outlines an agenda for future research.

5.3 Electricity Paradigms Shifts

It is electricity’s fundamental role in our everyday lives that makes its planning approaches produce significant impacts on our well-being [99]. Conventional electricity planning is based on centralized generation, delivery, and consumption of modern energy services. Technological invention of high voltage alternating current (AC) power in late 19th

century, combined with the ideological push for high modernist planning resulted in mass expansion of centralized nation-wide electricity grids electricity designed to convey electricity perpetually to the energy-hungry masses of residential, commercial and industrial consumers [50], [56], [100], [101]. The centralized energy paradigm underpinned unprecedented growth in the 20th century and has undoubtedly been the harbinger of astounding feats for economic and social development. However, the present realities of global climate change and the electricity poverty challenges of over 1 billion people demand a rethinking of its approaches [102]. Centralized systems, by design, reduce the ability of individuals and communities to exert control, though the desire for control over energy has long-standing. Now, there is an interesting change where technology is reducing the need for high modernist planning that birthed the centralized grid and the advances in distributed energy technology is a tide-turning catalyst that is transforming electricity provision at an unprecedented pace and presents an opportunity for envisioning a low-carbon energy future [103].

The distributed energy technology, including distributed and decentralized self-generation and energy storage, reduce consumers' dependence on traditional forms of electricity provision through the centralized utility and grid. These technologies allow consumers to produce their electricity, therefore evolving from passive consumers to active prosumers, and instigating a shift in the social organization of actors and roles in energy planning [56], [103], [104]. Therefore age-old claims for increased control and independence and democratized systems now have a foothold enabled by technological innovation [104].

Electricity infrastructure, on the surface, appears to be primarily technological, yet it also redistributes social power, entrenches social behaviors, and limits the choices (and therefore, the power) available to consumers. It is built in such a way as to be somewhat invisible, and offer some choices today while precluding future choices and possibilities, and determines the haves and have-nots of society [45], [49], [50]. Transitioning from centralized to distributed electricity infrastructure gives consumers greater access to choice and ownership by giving them access to means of electricity production, thereby promoting social capital, local governance and independence [58], [105]. With access to distributed generators such as solar rooftop systems and diesel generators, consumers are not only making autonomous decisions about their consumption anymore but also about generation and distribution. Decentralized generation transforms local scale of actors – households, communities, and individuals - from passive recipients and consumers to active planners and producers of electricity (also known as *prosumers*) [106].

Decentralized and distributed energy technologies disrupt the traditional producer-consumer relationship, making it more multilateral and iterative. It moves electricity planning from solely regional governance to households and community governance as well [57]–[59]. This disruption means that the center of power and decision making for achieving the low-carbon transition and universal access may no longer solely be with the conventional stakeholders such as governments and private utilities, but also with households and communities. Some papers have highlighted the need for new governance and adaptive planning approaches that suit this impending paradigm shift [45], [107], [108]. Even the United Nations, in a policy brief, recommended that sustainable development goals be linked

to ensuring people's control over energy choices and their capacity to manage their energy [55]. The increasing technological innovation and affordability of solar energy technologies are giving rise to increased decentralized generation using, even in the Global North where central systems are highly reliable. As prices fall, and consumers desire increased autonomy, decentralized solar generation, and energy storage present existential threats to the traditional form of electricity provision – through the central grid. This has implications not only for high-reliability contexts, where grid defection is on the rise but also for low-reliability contexts where dependence on a central grid was never fully established [103]. This global paradigm shift represents a new frontier in energy planning and will disrupt the social dynamics of electricity provision. It will require a systematic change in existing energy planning approaches. I explore how socio-energy concepts have framed this transition and introduce an additional concept, energy sovereignty, to understand and analyze this shift to increased autonomy and control.

5.4 The Role of the Prosumer

In this section, I explore the rise of prosumers around the world to illustrate a similar phenomenon in diverse contexts. The goal is not to compare, but rather to illuminate what one can learn about the diversity of prosumer realities. It is essential that I outline the diversity of prosumer realities in the Global North and Global South. I use the case of prosumers in Nigeria as an example to illustrate that some contexts do not have the emergent transition from passive consumers roles because of low reliability or non-existent central systems. Instead, it is active prosumer roles that have always been the status quo. Embracing and acknowledging the diversity of prosumers allows us to draw insights about imagining an energy future by seeing similar active prosumers roles in very different socio-political and economic contexts. Most of the literature engages with prosumers from the perspective of a reliable, functional central system from which consumers reduce their dependence. However, the prosumer in the global south does not represent a reduction but a current state of less dependence due to low reliability. The cost and environmental inefficiencies of traditional forms of prosumer roles in the global south using expensive and polluting diesel generation represent non-ideal goals. I note there is an important distinction in that its high financial and environmental cost to its owners are not empowering nor by choice [104]. However, this status quo represents an opportunity to be co-opted by distributed renewables – maintaining localized control without the insecurity of diesel supply and public health risks. The falling cost of distributed renewables represents a common ground of convergence for both the global north and Global South to shape their energy future.

5.4.1 Nigeria

Its electricity poverty has thoroughly shaped the cultural and economic landscape of Nigeria. Nigeria is the second largest economy in sub-Saharan Africa, after South Africa and yet 60%

of its citizens live on less than US\$1 per day [109], [110]. It has a population of about 190 million people with about 40% lacking access to electricity, and millions more are connected to an unreliable grid that does not meet their daily energy needs [28]. Those with grid connections only receive power for about 6-8 hours a day [63]. However, Nigeria is Africa's largest oil and gas producer, ranked seventh in the world in 2013 [111], and has abundant solar and wind energy potential. The persistence of electricity poverty in Nigeria despite its abundant resource potential is evidence of the importance of questioning the control and planning of its systems in order to solve its electricity poverty and mitigate climate change [112].

Of Nigeria's grid installed generation capacity at 13 GW (70% of which is fueled by natural gas), only about 3 - 5 GW has been operational the past few years. The remainder is unavailable due to gas unavailability, water shortages, and infrastructure breakdown. About 70% of its grid generation capacity is natural gas, and 30% is hydropower. Nigeria has a grid-based load forecast of 19 GW, excluding its latent demand that is suppressed by unreliable service provision [16], [63]. This mismatch in supply and demand is partly filled using unregulated self-generation [16]. The true power in Nigeria lies in the off-grid diesel generator. Driven by necessity due to low grid reliability, Nigerians generate their electricity using off-grid diesel generators [26]. Businesses, communities, and households act as autonomous system operators and planners, as prosumers. For many Nigerians struggling with unreliable electricity supply, exercising energy sovereignty is an act of survival rather than a choice. Estimates suggest that Nigeria has between 8 and 14 GW of distributed off-grid diesel generation capacity [96]. In 2012, more than 10 TWh of Nigeria's electricity demand was met by backup diesel generators that cost about 300% more than electricity from the grid [27].

While diesel generators give some Nigerians autonomy over their electricity generation, they are still dependent on the supply of diesel in the country which is quite expensive. Furthermore, the environmental and health impacts of diesel generators are significant. Diesel exhaust contains more than 40 toxic air contaminants, including many known and suspected cancer-causing substances, such as benzene, arsenic, and formaldehyde. It also contains nitrogen oxide, a significant ozone-depleting pollutant. Nigeria also has one of the highest prevalence of asthma in Africa, and there is indirect evidence of the impact of diesel exhaust on lung cancer. [113]

5.4.2 California

California has a population of about 39 million people and 100% electricity access. In 2016, California had the largest gross domestic product in the United States and a per capita personal income of \$56,000 [114]. The primary focus of electricity planning in California is decarbonizing the centralized grid while maintaining reliability and affordability. Therefore, there are state-sponsored incentives to encourage the prosumer's use of decentralized renewables. Lawmakers in California have pushed for pathways for its citizens to make their own generation choices motivated by the potential for those choices to support climate

change mitigation objectives and drive economic development in the state. For example, Assembly Bill 32 requires statewide greenhouse gas emissions reductions to 1990 levels by 2020. To help achieve this reduction, the legislation passed a renewable portfolio standard requiring that 33% of the state's electricity supply must come from renewable resources by 2020 and recently raised this target to 50% by 2030 [115].

The dominant means of electricity access in California is the centralized grid and grid-connected distributed solar systems. California has a grid generation capacity of 79 GW, about 50% of which is natural gas, 28% renewable energy, 12% large hydropower and 10% nuclear power [115]. California also has the largest installed capacity of distributed generation in the United States – about 5.6 GW which represents over 10% of the state's peak demand at 50 GW [97], [116].

Who plans? California has a primary energy policy and planning agency called the California Energy Commission which develops energy forecasting studies and planning standards. California also has an independent system operator in charge of providing ancillary services and balancing real-time supply and demand. A majority of the electricity supply (about 65%) is planned out by investor-owned and public utilities, then regulated and approved by the California Public Utilities Commission (CPUC) [117], [118]. About 5% is supplied by self-generation and co-generation. The remaining 35% of supply is planned by community choice aggregators, rural electric cooperatives and through the state's direct access program [118]. Grid-connected rooftop solar systems are the most common means of distributed generation in California. Without incentives specifically designed for low-income communities, attaining solar power can be cost-prohibitive. State and non-state actors in California have made efforts to create solar initiatives targeted at low-income communities, thereby addressing justice issues of inclusion and intra-generational equity.

California serves as working evidence for how technology advancements are enabling consumers to engage in electricity decision-making with a central planner. Asking “by whom?” in California reveals how energy sovereignty enables the consumer to contribute directly to the low-carbon energy transition by choosing clean electricity through self-generation or community choice aggregators, without depending solely on the central planner to decarbonize the electricity sector. It also means potentially deepening social and economic inequalities for those who continue to depend on the centralized grid.

5.4.3 Discussion

Falling prices of distributed renewables push towards a commonality amongst prosumers in the Global North and in the Global South that did not exist before. This common goal, in two very different contexts, could provide insights for shaping the global energy transition.

Studying Nigeria and California illustrates different aspects of prosumers – one emergent, the other as an incumbent. Table 2 highlights the position of the central planner in enabling consumer choices. Table 2 also shows that Nigeria, despite having four times as

many people as California, has less operational grid generation capacity than the distributed solar capacity in California. Nigerians pursue self-generation at a high cost relative to its grid and California. These cases emphasize the role of planning by depicting how differently producer-consumer relationships could evolve in different planning contexts.

Furthermore, these two cases underscore the potential of sharing ideas across diverse energy contexts [94], [112], [119]. Future work will include a comparative analysis that helps deepen the theoretical understanding of the role prosumers play in realizing the socio-energy goals of the energy transition including energy justice, energy democracy, and energy sovereignty. This illustration of California and Nigeria shows a common goal for independence driven by diverse motivations including affordability, reliability and climate change mitigation.

	California	Nigeria
Distributed generation capacity (GW)	5.6	11 ⁶
Centralized grid generation capacity (GW)	79	4.6 ⁷
The ratio of distributed to centralized capacity	7%	240%
Levelized cost of distributed generation (\$/kWh)	0.08-0.22	0.32 - 0.49
Retail cost of centralized generation (\$/kWh)	0.08-0.44	0.03-0.09

Table 5.1: Capacity and cost of centralized and distributed generation in California and Nigeria.

5.5 Socio-energy Concepts

Recently, social scientists and energy planners have shown increased interest in exploring questions of equity and justice related to energy production and consumption. Thus, there is growing literature that explores challenges of a low-carbon energy transition and alternative approaches to energy planning, that theorizes conceptual lenses to broaden energy planning

⁶ This represents the average of the estimated range of 8 -14 GW [96].

⁷ This is the operational generation capacity in Nigeria as of September 2017 according to the Nigerian Electricity System Operator [151].

beyond techno-economic analysis and integrates social considerations [120]. Miller et al. [92] propose a socio-energy systems framework that serves as a forward-looking design concept that can be used as a conceptual lens through which to view, alter, expand and design an energy future [92]. The socio-energy systems framework socializes energy planning by integrating the human and social dimensions. Expanding energy planning through a socio-energy framework acknowledges the significance of existing energy goals such as energy security and expands the scope using additional concepts. There have been several concepts that reflect this sentiment of Miller's socio-energy systems framework. The first of this is energy security, which has been expanded to include equity and environmental protection through a framework known as the energy trilemma [121]. Therefore the energy trilemma goals are: to produce and distribute sufficient energy to reliably meet demand, to minimize the cost of that energy and ensure affordability, and to achieve environmental goals associated with energy production, such as low atmospheric emissions of carbon or other pollutants [92]. Other concepts that have arisen in the literature are energy justice and energy democracy. This section provides an overview of these concepts, introduces an additional concept – energy sovereignty, and identifies a unifying tenant for the three concepts.

5.5.1 Energy security

Energy security - ensuring the uninterrupted availability of energy at an affordable price to meet economic development - has been the main approach steering conventional energy planning [84], [85], [122]. Energy security frames energy planning as a matter of which technology to choose, how much to pay for them and, increasingly so, how much its carbon emissions are [92]. Energy policy cannot focus simply on the economic perspective anymore due to the growing constraints of climate change and electricity poverty [121]. The concept of energy security has been useful in its management of risks [84], and its focus on adaptability to energy supply threats [85]. It asks “for whom, for which values and from which threats?” [123], [124]. However, who decides the answers to these questions is glaringly absent in its scope. Energy security does not account for justice concerns, nor does it question the socio-political hierarchy of who plans for energy. The concept of energy security is critically silent on who bears the costs of energy provision. This is the chief concern of energy justice, which champions the fair dissemination of both the benefits and costs of energy services and calls for representative decision-making processes [122].

5.5.2 Energy justice

Energy justice is defined as a global energy system that fairly disseminates both the benefits and costs of energy services and one that has representative and impartial energy decision-making [125]–[129]. The conceptual framework of energy justice therefore involves burdens, or how the hazards, costs, and externalities of the energy system are disseminated throughout society; benefits, or how access to modern energy systems and services are

distributed throughout society; procedures or ensuring that energy decision-making respects due process and representation; and recognition, that the marginalized or vulnerable have special consideration [125]. Recent research efforts have used the concept of energy justice to expand upon energy security in planning [125]–[130], and have conceptualized a useful framework that raises the pertinent question: “Energy for whom and for what at whose cost?”. The framework consists of eight dimensions: availability, affordability, due process, good governance, sustainability, inter-generational equity, intra-generational equity, and responsibility [126].

Energy justice calls for the fair distribution of energy benefits and like energy sovereignty, calls for greater inclusion in the decision-making process for not only policymakers, energy regulators and technical experts but any stakeholder along the value chain [126], [127], [129]. Addressing the distribution of costs and benefits makes the concept of energy justice pertinent to ensuring that the pursuit of energy sovereignty does not exacerbate injustice and inequalities. Energy justice offers a necessary and useful framework from which to view energy sovereignty by considering who gets to decide, whose interests are prioritized and recognized, how equitable the decision-making process is and the impartiality and fairness of institutions [126].

Energy democracy ties to energy justice in the fact that distributed renewables enable energy democracy in such a way that provides a path to a better quality of life [131]. The energy justice frame encompasses issues of both energy production and consumption, alongside issues of distribution and procedure [132]. Therefore, energy justice is also not only concerned with substantive just outcomes but also decisional procedures [126], [133], which harmonizes its agenda with energy democracy.

5.5.3 Energy democracy

Energy democracy is an emergent social movement that advances low-carbon energy transitions, links social justice and equity with energy innovation while reclaiming and democratically restructuring energy regimes [51]. Energy democracy refers to political calls for and the institutionalization of more participatory forms of energy provision and governance [94]. From a technological perspective, energy democracy is viewed as the adoption of decentralized generation, and from a political perspective as the collective ownership of energy systems and the energy sovereignty of a state [94]. Energy democracy represents the hope for a transforming traditional energy paradigm through the rise of the prosumer and new forms of governmentality [104]. It is useful to consider energy democracy as an umbrella concept that encompasses decentralized energy provision; collective forms of ownership of energy infrastructures and utilities; and energy sovereignty over resources [94].

5.5.4 Energy sovereignty

Like energy democracy, energy sovereignty is an emergent social movement. I define energy sovereignty as the ability of people to control their energy systems and make decisions on energy generation, distribution and consumption in a way that is appropriate within their ecological, social, economic and cultural circumstances, provided that these do not affect others negatively [44], [53]. Energy sovereignty emphasizes the ability of households and communities to manage, control and make energy decisions. Energy sovereignty is about empowering people to play an active role in the planning, acquisition, generation, and distribution of a resource that shapes their lives. Energy sovereignty represents a call for localized models of energy provision over which people can make decisions that affect the way they use energy [44], [134].

The concept of energy sovereignty, like food sovereignty, is applied in different ways in different contexts. The energy sovereignty concept was inspired out of the food sovereignty movement [53], [135], [136], which called for the right of people and communities to determine their food systems and to shape and craft food policy [124], [136], [137]. Food sovereignty is an idea that seeks to transform current food systems to more democratic, decentralized and sustainable systems [54]. Both concepts call for returning control and management of resources to the people but have diverse manifestations in practice.

For example, in Brazil, there is competition for land to grow food versus land to grow biofuels, so energy sovereignty has been used as the impetus for different agendas. Some believe that biofuels will enable energy independence and decarbonization, while others believe that biofuels will exacerbate social and environmental problems domestically. For both parties, Brazil's energy sovereignty means reclaiming control of the land [135]. For example, in Ecuador, the government uses energy sovereignty to justify resource nationalism as its primary planning policy. This was the driver behind the construction of large-scale infrastructure projects such as major hydroelectric dams despite significant environmental protests by local communities. To the government in Ecuador, energy sovereignty does not mean local decision-making and decentralized renewable energy; rather it means freedom from dependence on imports and energy self-sufficiency through large-scale hydropower [138]. On the other hand, the city of Barcelona is recently spearheading a new government measure aimed at enabling a transition to energy sovereignty based on a 100% renewable energy supply, zero emissions and democratic access [139]. These examples are in contrast with each other and highlight the polysemic nature of realizing and attaining energy sovereignty.

Conventional notions of energy sovereignty refer to national level control of natural resources and the struggle against private and foreign companies extracting energy resources. These conventional notions attach emphasis to the role of the state but have diverse realities in practice [94]. However recent conceptualization of energy sovereignty emphasis its call to locate sovereignty within people and communities' ability to choose [44],

[53], [140], and this call is catalyzed by the technological innovation in decentralized and distributed systems

Energy sovereignty should be distinguished from its closely related concept – energy security. Energy security and energy sovereignty are often misconstrued as the same, particularly from the state’s perspective and with the increasingly broader conceptualization of energy security that incorporates energy equity and environmental sustainability [128]. However, it is important to emphasize the social movements of energy sovereignty by consumers that are about having agency, control, and choice over the energy systems they depend on.

Energy sovereignty questions the entrenched notion that public and private utilities should have paramount authority over electricity decisions. It deemphasizes the hierarchical network of actors behind electricity infrastructure and shifts their roles in planning [95]. Traditionally, the primary roles of consumers are as recipients of energy products and services, and as client-citizens shaping the acceptance or resistance of energy plans [59]. Energy sovereignty reframes these roles, and this has increasing importance as access to distributed generators shifts consumers from passive recipients of central planning outcomes to active planners themselves [59], [108], [141], [142]. The concept of energy sovereignty can be conceptualized along two dimensions:

- In the ability of people to control and regulate their energy systems (self-generation).
- In the ability of people to engage in decision-making and craft policy (participatory and democratic planning processes).

These dimensions are reflected as well by key aspects including socio-ecological reciprocal relationships, local control of energy resources, and participatory decision-making processes [44]. In simple terms, energy sovereignty can be thought of as the ability to decide what is on the list of choices, as well as the ability to choose from the list. The desire for choice, self-empowerment, and independence is reviving energy sovereignty globally [49], [56], [143]. The pursuit of energy sovereignty is a reaction against lack of control and access to energy decision-making processes that have impacts on the daily lives and welfare of its consumers [141]. It also highlights that the by-products of centralized planning are large-scale systems that cannot always fulfill the wants of its users and in turn limits opportunities for choices [49], [143].

5.6 Convergence of Energy Justice, Energy Democracy and Energy Sovereignty

Nigeria and California illustrate that the desire for individual agency over electricity decisions is common across diverse cases but manifest differently depending on the incumbent planning climate. The pooled wisdom of energy justice, democracy and sovereignty are now equipped with the increased agency of prosumers that are, in turn,

empowered by technological innovation, and therefore making these concepts increasingly important and relevant for shaping the low carbon transition. There is no guarantee that decentralized and socially controlled energy systems will be more just and democratic. It is, however, a necessary enabler in the struggle to attain broader socio-energy goals.

Concept	Key Principles
Energy Security ⁸	Availability, accessibility, affordability, acceptability [84], [123]
Energy Justice	Availability, affordability, due process, good governance, sustainability, intergenerational equity, intragenerational equity, and responsibility [125], [126]
Energy Democracy	Decentralized energy generation, public and cooperative ownership, energy sovereignty [94] Prosumers as ideal-typical citizens, participatory governance, civic ownership and popular sovereignty [104]
Energy Sovereignty	Connection to socio-ecologically responsible relationships, self-determination, participatory decision-making and innovation [44], [134] Local control of energy systems and self-generation [53]

Table 5.2: Key principles of socio-energy concepts

I review the theoretical foundations of energy justice, energy democracy, and energy sovereignty in order to synthesize a conceptual foundation for shaping the energy transition. There is diversity in the agendas of socio-energy concepts. I acknowledge that struggles for energy democracy, energy sovereignty, and energy justice have very different practical realities; yet there are also unifying tenets and goals. The presence of different meanings does not mean the existence of different conceptualizations, only that the same concept can take different expressions under different conditions [123].

Key to these concepts is recognizing the common basic tenet – reorganizing energy systems in a more just, sustainable and democratic way- that results in heterogenous approaches, in

⁸ This refers to a contemporary conceptualization of energy security that is beyond its classic notions of “uninterrupted availability of energy sources at an affordable price” [123].

reality, depending on the context of application [94], [136]. Firstly, these concepts are similar in the fact that they first emerged from social movements, and are understood with variations, with no standard commonly accepted definitions [144], [145]. Iterations of conceptualization have coalesced and defined firmer definitions and boundaries. These concepts also thrive in this polysemic nature, because the flexibility of definition allows it to frame diverse energy contexts around the world without imposing a single definition [144]. Energy justice, energy democracy, and energy sovereignty are increasingly used by grassroots social activists to call for increasing social justice and equity in energy transitions. The commonality amongst the three is that they are both concepts with academic theorizations and emergent social movements with immediate applications or use.

The energy democracy agenda is rooted in ideas of sovereignty and self-determination. Becker et al. [94] and Szulecki [104] conceptualize energy sovereignty as a component and typology of energy democracy, and Van Veelen [145] cites energy democracy as a necessary process for implementing demands for energy justice. Energy sovereignty complements energy justice by emphasizing the need to recognize the autonomy and self-determination of people in framing energy decisions that affect them [134]. Broto et al. [134] propose that energy justice concepts integrate energy sovereignty to emphasis self-determination as a complementary aspect of energy justice.

All together, these three socio-energy concepts recognize and highlight low carbon energy transition as an opportunity to restructure socio-technical paradigms [51], [99], [104], [126], [132], [146]–[148]. Together, these concepts represent the struggle over “who owns and controls energy and how, where and for whom energy is produced and consumed [145], [148]. I propose here that, in addition to this, energy sovereignty and energy democracy complement energy justice and expands it to also consider the “energy by whom?” question. This is an important consideration that is needed because technological advancements in distributed energy resources, primarily distributed electricity generation, are empowering small-scale actors such as households and communities to autonomously plan for and manage their electricity [56]. Distributed generation technologies will transform not only how electricity is provided, but also who plans for it. This emergent behavior is the beginning of a paradigm shift that makes “Energy *by whom?*” a crucial question that also deserves attention.

I add that increasingly, these concepts also represent the struggle over “energy by whom?”. Therefore, synthesizing the theories and frameworks of these concepts emerge a critical consideration: *Energy by whom, for whom, for what, and whose costs?*

5.7 Multi-dimensional Framework of “Energy by whom?”

Sovacool et al. [129] created dimensions for applying the concept of energy justice to practical energy policy and planning. I follow their approach and introduce “Energy by whom?” as a conceptual framework for understanding the paradigm shift in electricity provision across three dimensions:

- Technology scale
- Actors
- Roles

Dimension	Description
Technology scale	The unit of production and distribution such as centralized grids, microgrids, distributed generators, solar home systems and pico-systems. There are also hybrid configurations such as grid-connected distributed generators.
Actors	The scale of social organization such as households and communities, state actors such as federal ministries and municipalities, non-state actors such as investor-owned utilities and solar service providers.
Roles	<i>Actors</i> can have multiple roles at the same time, making energy decisions as consumers, as producers, and as planners.

Table 5.3: Multi-dimensional “Energy by whom?” framework

This framework illustrates how both technological and social innovations are disrupting traditional electricity provision. It depicts the relationship between the technological scales of electricity generation and the socio-political and economic complexities of recognizing choice and agency at multiple actor levels from the perspective of the producer. The framework represents a snapshot in time, due to the temporal nature of the social, technological and political characteristics of each dimension. There is precedence in the literature for thinking about sovereignty along multiple dimensions [54], and thinking about energy transitions along scales of technology and social organization [95], [149]. These three dimensions together are an important way of assessing “energy by whom?” holistically because the scale of technology inherently precludes certain choices to the producer because it determines who the actors are and the type of roles the actors can play in the decision-making process. The blue arrows in the center portray the increasing complexity of achieving autonomy with increasing system scale because there are more consumer choices to be recognized on a centralized regional grid than on a community microgrid, and more socio-political barriers and less technological flexibility to acknowledge those choices. The red arrows represent social and technological innovations that disrupt and alter modes of electricity provision.

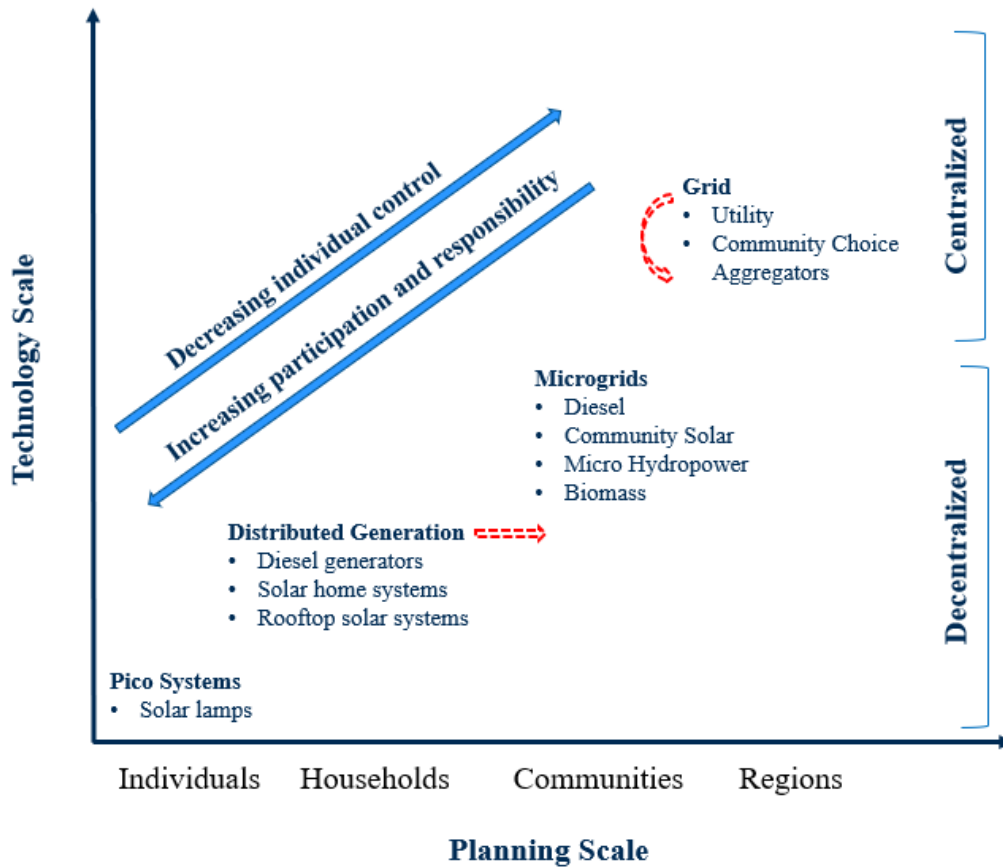


Figure 5.1: The "Energy by Whom?" framework applied to electricity provision

The current paradigm of provision through the centralized grid has many advantages, particularly the ability to offer large amounts of electricity to many. However, in order to do this, it has a standardized and rigid configuration. This rigidity results in technical and operational vulnerabilities and low flexibility. I argue that the centralized grid also creates a form of social vulnerability by restricting consumer agency and choice. Operating the centralized grid together with distributed and smart grid technologies can help overcome these vulnerabilities [150]. Hybrid configurations such as grid-connected solar systems at the household and community scales offer consumers the benefits of the centralized system together with some level of autonomy. Apart from the technical and operational advantages that hybrid configurations offer to the grid, there are new opportunities for consumer agency by pushing forward actors into a space of engagement that is conventionally excluded from the planning process. For example, consumers can now offer centralized grid operators ancillary services through demand response. Here, the ability to shift their electricity demand is the resource that enables them to plan together with a central planner such as an electric utility.

This framework is versatile because it can be adapted to the resource context and planning paradigm of the region in question. Energy sovereignty, together with energy justice and

energy democracy expand the notions of energy planning and offers context-dependent frameworks that can be incorporated to enable sustainable planning towards the low carbon energy transition and universal energy access [108], [141]. “Energy by whom?” raises emphasis on who controls energy, through calls for democratic participatory planning for the centralized grid in one context, and self-generation in others. Planning approaches will need to stay nimble and flexible to adapt to technology advances that will change the way energy stakeholders interact with each other and with the infrastructure. Our future work will include further research on understanding the motivations behind pursuing energy sovereignty, and on how to incorporate the use of energy sovereignty and energy justice frameworks in planning practice.

5.8 Conclusion

The energy access and the low carbon challenges require a change in the energy infrastructure and governance paradigm. The rise in decentralized energy technologies highlights the need to understand who plans for energy. A new energy paradigm to achieve universal access and enable a low-carbon future will require revolutionary changes in the way energy is thought of and planned for. Energy planners must tackle this transition not only regarding the technological and economic impacts on the infrastructure but also in terms of its socio-political implications. These implications are diverse and dependent on the planning context. Motivated by this burgeoning discourse, I argue that planning approaches, now more than ever, must be dynamic, responsive and, most importantly, must be able to consider both the infrastructure design and social implications of how to achieve decarbonization and universal access. Highlighting the individual contributions of each concept is not as important as emphasizing the commonality amongst them. Energy democracy, energy justice, and energy sovereignty are concepts and social movements that converge towards a common call for just and sustainable energy transition and highlight an impending technical, social and ecological transformation [148]. They represent opportunities to re-imagine alternative energy provision and governance approaches. I propose a conceptual framework that considers the “energy by whom?” question as a useful way of understanding these paradigm shifts in electricity provision.

The purpose of our work is to push forward the concept of energy sovereignty to initiate a discourse on its electricity planning implications. I propose that the combination of energy justice, energy democracy, and energy sovereignty frameworks broaden the scope of planning approaches that highlight the socio-energy dimensions and could guide equitable decision making and design process for a low carbon energy future.

Chapter 6

Conclusion

6.1 Assessing Electricity Pathways in Sub-Saharan Africa

Sub-Saharan Africa, home to more than 900 million people, is the most electricity-poor region in the world. More than 600 million people lack access to electricity, and millions more are connected to an unreliable grid that does not meet their daily energy service needs. According to the International Energy Agency, at the current pace of electrification and population growth, more than half a billion people are expected to remain without access to electricity by 2040, and full electricity access in the region is estimated to be accomplished until 2080 [5]. Sub-Saharan Africa is burdened with a persistent electricity gap comprising both the supply-demand mismatch in grid-connected regions and the lack of access in off-grid regions. Closing the electricity gap in Sub-Saharan Africa is a multi-dimensional challenge with significant implications for how to frame the region's energy planning as a whole.

Persistent electricity scarcity has crippled the region's economic growth and prevented it from attaining several of its health and education development goals. I outlined the main drivers of this scarcity in Chapter 2 and Chapter 3 including lack of generation capacity to supply power to grid-connected regions, the absence of proper grid infrastructure to deliver this power, regulatory impediments to providing steady revenue for maintaining and investing in new generation capacity, and dispersity of population in remote areas. As of 2012, sub-Saharan Africa's installed generation capacity was a mere 90 GW—about 0.1 kW per capita—in stark contrast with wealthier economies that have installed capacities ranging from 1.0 to 3.3 kW per capita. The region's inability to provide reliable electricity has led to the prolific growth of inefficient and expensive on-site self-generation in industrial, commercial, and even residential sectors. This lack of systematic planning for the power sector has resulted in a system with high transmission and distribution losses (averaging 18% across the region when South Africa is excluded) and created a high dependence on large dams and expensive diesel plants. The region's dependence on fossil fuel plants creates a multifaceted problem of supply and price variability, with fuel producers curtailing supply under low prices and consumers suffering economic losses during periods of high prices. Also, climate change is projected to have a substantial impact on the reliability of hydropower resources in sub-Saharan Africa. Erratic rainfall patterns and prolonged droughts can reduce hydroelectric output and force extended outages. While the region contributes the least to greenhouse gas emissions, it is most vulnerable to climate change impacts such as droughts and reduced agricultural yields. These challenges present an opportunity for sub-Saharan countries to design low-fuel, low-carbon power systems based on wind, geothermal, and solar technologies and to use responsive and efficient demand management strategies. I chose to focus on the region's lack of electricity generation and explore potential capacity expansion pathways to close the gap.

The region is home to abundant fossil and renewable energy sources. The technical potential for generation capacity is estimated at 10,000 GW of solar power, 350 GW of hydroelectricity, and 400 GW of natural gas, totaling more than 11,000 GW. I use Chapter 2 to explore the role of renewable energy in filling the electricity gap in Sub-Saharan Africa. I outlined the limiting factors in the region's electricity development including the technical, financing, and policy mechanisms that are needed to ensure the development of the renewable resources. After an extensive review of the existing literature, I identified seminal papers which model capacity expansion for the region as a whole or a single country (Kenya). The review shows that the region's lack of grid infrastructure can be transformed into an opportunity to lead the way toward better-designed, more efficient, sustainable power systems without being hindered by legacy carbon-intensive assets. Due to the scale of electrification required, I argue that it is essential that both private and public stakeholders create mechanisms to facilitate grid extension and micro-grid deployment in order to reach unconnected regions. Sub-Saharan Africa also needs utility and tariff structures to be fair, stable, and sustainable to ensure cost-effective and reliable delivery to end users, as well as proper maintenance of valuable energy infrastructure.

Filling the electricity gap with renewable sources will entail economic and environmental trade-offs because of the region's unique combination of challenges and opportunities. I reviewed the potential of regional power pools that allow countries to aggregate resources and extend grids across national borders, capitalizing on regional diversity in resources and demand. Four regional power pools already exist, but only about 7% of electricity is traded across international borders, mostly through the South African Power Pool. Power pools could facilitate additional strategies to incorporate large amounts of variable renewable generation such as the use of existing reservoir hydropower to provide storage, the deployment of novel chemical and mechanical storage technologies, and the adoption of widespread demand response programs across the region.

Though challenging, the literature review reveals opportunities to increase the use of clean energy and build intra- and international cooperation in Africa. The case studies show that renewables are now cost competitive and that fuels such as natural gas can play a role in providing system flexibility until grid storage costs decline. The analysis shows that fuel choices should be considered cautiously—mainly coal, which is shown to be a costly pathway to electrification. The review also shows that the scale of centralized generation expansion required to meet moderate load growth by 2040 is significant compared with past investments in power systems and the rate of system expansion in many countries in the region. Current investment in sub-Saharan electricity systems is about US\$8 billion a year. This is inadequate to overcome the existing infrastructure challenge, to expand access and coverage, and to meet the growth in demand. Therefore, achieving full electricity access will require combining many pathways and strategies, such as synergies between centralized and distributed energy systems, bolstered financial support and investments, and improved institutional capacity and management. [16]

The design of sustainable electricity systems is needed to fuel development requires context-specific power system modeling. Modeling data requirements, however, can be challenging for researchers to access, particularly in regions with low rates of electrification. Lack of data is hindering analysis of future grid designs in many countries in the region. The development of robust planning tools that have relatively low data requirements will permit the widest vetting of renewable energy projects based on their energy, social, and environmental costs and benefits. Designing, testing, and assessing different expansion scenarios for sub-Saharan Africa is paramount to finding the optimal combination of supply, transmission, storage, and demand-side resources to fuel development and growth for the coming decades. Countries need to develop and adopt a host of data-driven integrated modeling tools for systems-level planning and operation on an unprecedented scale. Governments need to partner with academic institutions and private sector stakeholders to produce data in the quality and quantity required to provide decision makers with the right inputs for these modeling tools. This need justifies the development of the novel modeling solutions expounded in Chapters 3 and 4.

Together with a team at the Renewable Energy Appropriate Lab, I developed an open-access cost optimization capacity expansion model called PROGRESS (Programmable Resource Optimization for Growth in Renewable Energy and Sustainable Systems). The model is designed to explore and compare generation pathways for power systems expansion. The model has relatively low data requirements and is readily adaptable to specific modeling contexts. Its key value is enabling analysis for regions with limited power systems data. It allows for clear sensitivity analysis by duplicating the model over varying scenarios and illustrating the trade-offs in terms of costs, fuel choices, and policy targets. This modeling tool permits not only energy system experts to evaluate the costs, benefits, and impacts of various expansion pathways, but also facilitates a dialog with policymakers in other areas and with the public over both the need for, the costs, and the impacts of different energy pathways and strategies. PROGRESS allows us to understand the cost tradeoffs of different configurations of capacity expansion and how policy decisions and market conditions may influence the least-cost utility-scale energy generation mix for a country or region. Lack of high quality and high-resolution power systems data is hindering analysis of future grid designs in many countries in Sub-Saharan Africa. PROGRESS is one leverage point of increasing power system analysis in the region to inform the critical energy decisions that Sub-Saharan African countries will have to make in the next decade that is constrained by the urgent need to electrify their population while also mitigating carbon emissions.

I used the reduced form of PROGRESS to assess capacity expansion pathways in Nigeria. I needed to use the reduced form due to a limited hourly resolution on electricity demand and renewable energy production data. I used average capacity factors for each resource and approximate capacity values of solar and wind. I find that Nigeria's energy policy Vision 30:30:30 significantly underestimates the role of solar in expanding on-grid capacity and can increase its current target of 30% non-hydropower renewables in its generation mix to at least 50% at a lower average levelized cost of electricity. I also find that coal and nuclear deployment are unnecessary and expensive investment decisions that will lock Nigeria into a fossil-heavy pathway that is neither diversified, resilient nor sustainable.

I used Kenya as the test case for developing the full form of PROGRESS which uses hourly resolution data. The process of building and testing progress is outlined in the Appendix. Preliminary analysis on Kenya reveals similar results as an analysis published about Kenya using the SWITCH model [36]. Kenya has the advantage of geothermal as a baseload renewable source to put it on the low-carbon energy pathway. It also has abundant wind resources. However, Kenya is pursuing 4.5 GW of coal development in its Lamu and Kitui counties which both PROGRESS and SWITCH models have proved to be unnecessary and costly investments.

Sub-Saharan Africa is primed for an energy transformation kindled by its vast renewable energy potential. The key conclusions that emerge from the literature review in Chapter 2 and capacity expansion analyses in Chapter 3 and Chapter 4:

- While sub-Saharan Africa has significant fossil fuel resources, many of which are the focus of domestic and international “resource races,” investments in and use of fossil fuels should be judicious given that the exploitation of fossil fuels, even in energy-limited countries, often comes at the expense of the development of sustainable energy sources.
- Decades of experience show that fossil fuel energy development does little to increase energy access, which is lower in sub-Saharan Africa than in any other region.
- Africa has exceptional solar, wind, geothermal, and biomass resource potential, both on a per capita basis and in terms of resource diversity. Africa could thus achieve high levels of energy services with very low carbon emissions.
- Successfully integrating large shares of variable renewable resources will require high grid flexibility, currently hindered by the difficulty of operationalizing regional power pools and the high cost of energy storage. I showed in Chapter 3 how the declining cost of energy storage presents opportunities for long-term energy planning using the case of Nigeria.
- Advances in smart grids and information and communication technologies (ICTs) will enable the region to take full advantage of its exceptional renewable resources and provide the grid operational flexibility that renewables require.
- Operational power pools combined with strategic policies and actionable targets could quicken the pace of electrification across the region.
- As these challenges are addressed, fossil fuels, particularly natural gas, will likely remain a part of the region’s transition to a low-carbon electricity grid.

- Investment in renewable energy is proving a more sustainable and cost-effective path to meeting Africa’s dual challenges of economic empowerment and energy access.
- A clean energy path benefits significantly from well-functioning regional power pools. National efforts to develop clean energy transition plans and policies aligning on-grid and off-grid energy service delivery are key, but added regional work—via regional power pools—can speed progress on meeting the joint goals of national and regional energy sufficiency, as well as full energy access across Africa.
- Worldwide, too little attention has been paid to ways of coordinating and integrating off-grid, mini-grid, and large utility-scale power systems. For African countries and individuals, the benefits of such a systems nexus can be transformative.

6.2 Introducing “Energy by Whom?”

The foremost challenges facing energy planners today are providing electricity to over one billion people living without access, and decarbonizing energy systems to mitigate climate change. Though conventional energy planning emphasizes large-scale centralized systems, renewable energy technology advances now enable small-scale actors to plan for decentralized systems on their own. Scholars have approached conventional energy planning through concepts such as energy security and environmental sustainability. Recent research efforts have also been made to incorporate the concept of energy justice and energy democracy. These research efforts raise the question: “Energy for whom and for what at whose cost?” However, “Energy by whom?” as a central question should also be addressed. I filled this gap with Chapter 5.

The emerging concept of energy sovereignty emphasizes this very question. Energy sovereignty is defined as the ability of individuals, communities, and people to make their own decisions on energy generation, distribution and consumption in a way that is appropriate within their ecological, social, economic and cultural circumstances, provided that these do not affect others negatively [44], [53]. It emphasizes the ability of communities, households, and individuals to plan for energy. Energy sovereignty complements existing socio-energy concepts such as energy democracy and energy justice and expands them to also consider the scales at which energy planning occurs. At both scales of energy planning – centralized and decentralized, the application of these socio-energy principles is boundless, calling for fair distribution of energy benefits and participatory decision-making processes and localized control of energy systems. The critical question I set out to answer is how energy planning approaches can adapt to these emergent concepts to foster a fair, just and equitable energy future.

I used archival sources and secondary data to conceptualize energy sovereignty, following similar approaches of conceptualization in the literature by Sovacool and Dworkin [126], Miller et al. [92] and Szulecki [104]. I used self-generation in California and Nigeria to

highlight the rise of the prosumer in starkly different planning contexts and emphasize the polysemic nature of being energy sovereign. In contrast to techno-economic planning approaches, socio-energy concepts like energy sovereignty thrive in diverse and sometimes contradictory interpretations. This ambiguity remains the delight and the burden of incorporating the human dimension into energy planning.

My work ultimately presents a new conceptual framework for energy sovereignty and understanding “energy by whom?” using actors, roles, and scales as the dimensions along which energy planning can be assessed. I argue that the framework can be used as both a descriptive tool to understand the multiple dimensions of energy systems and as a prescriptive tool to guide equitable decision-making in energy planning. Understanding energy sovereignty can broaden energy planning beyond conventional techno-economic approaches by highlighting agency and choice over energy systems. It provides a stepping stone from which to assess energy justice, energy democracy, equity and environmental sustainability. My work serves as an introduction to the concept and an exploration of its planning implications.

6.3 Contributions

My dissertation contributes to the fields of long-term energy planning and critical urban planning. I began by assessing the technical and social factors that create pervasive electricity poverty in Sub-Saharan Africa. I start here in order to identify lever points of investigation. One of the primary reasons for the electricity gap in the region is the shortage of electricity generation and underinvestment in capacity expansion. I proceed to focus on generation capacity expansion planning in Nigeria and Kenya. Despite its economic and geographic prominence, Nigeria is mostly secondary in the discourse on electrification in Africa, unlike Kenya. One of the reasons for this is that Nigeria is a difficult place to work in and does not attract small and medium private entrepreneurs the way most of East Africa does. Even more importantly, there is a paucity of power system data on Nigeria. Therefore, there has not been a recent capacity expansion analysis on Nigeria. My work filled this gap.

Together with a team at the Renewable and Appropriate Energy Lab, I also developed an open-access generation capacity expansion tool that requires low data inputs. Building this tool was inspired out of numerous studies during my research that I did not include in this dissertation. As I tried to use academic analysis to support social struggles for more sustainable energy systems in Southeast Asia and Sub-Saharan Africa, I came to see how big a barrier data access could be. I decided to explore levels of model complexity and data resolution that permitted modeling in the worst scenarios of data access. I hope that this type of first-order engagement will precipitate data collection and sharing, and thus inspire better modeling of countries usually left unstudied. The capacity expansion analyses on Nigeria and Kenya in this dissertation show that the falling prices of renewable energy and energy storage present a multitude of opportunities for them and the region as a whole to fill the electricity gap and usher in sustainable and modern electricity access for all.

Finally, I also observed that working on capacity expansion planning sparks the questions - who gets to plan for energy? Who has access to the tools that decide the energy future of communities and nations? I had the privilege of leading the Mekong Basin Connect Program, together with the Stimson Center. I hosted several dozen energy planning workshops with government stakeholders in Cambodia, Vietnam, and Laos. This experience brought these questions to the forefront of my mind. At the same, I was struggling to reconcile together the energy realities I had experienced in Lagos, Nigeria and Berkeley, California, along with the snippets I gathered on my travels. I found that there is a commonality of energy behaviors between Lagos and California, though these are starkly different places. I also began to explore informality and historical reactions against central forms of planning and delved deeply into the critical urban planning literature. Through these investigations, I found that the social movement of energy sovereignty – the desire for control over one’s energy – was this commonality among Californians and Lagosians, and many people around the world. Energy sovereignty, like many social struggles related to the control of energy, is longstanding. Now finally, the difference is that there are technology innovations that are bringing very different planning contexts onto similar grounds and empowering these social struggles.

Technological innovation, for all its power, can be neutral. However, its deployment defines the set of choices available to the consumer and re-distributes social power. These are the considerations and challenges that have fueled my dissertation. Therefore, the gleam in my eye is conceptualizing links between energy sovereignty, and the growing literature on energy democracy and energy justice. I call this link the “energy by whom?” framework – a way of incorporating the human dimension into energy planning that considers who gets to decide and who has control over energy. A framework that acknowledges energy as a commodity, as a system, as a resource, and as a social paradigm. The most important aspect of energy planning is the human dimension, encapsulated in the way planners envision energy goals. It is this vision that ultimately serves as the bedrock for a sustainable future. I hope that this dissertation contributes to the vision for a just low carbon energy future for all.

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Appendix

Sub-Saharan Africa			
Eastern Africa	Western Africa	Central Africa	Southern Africa
Burundi	Benin	Angola	Botswana
Comoros	Burkina Faso	Cameroon	Lesotho
Djibouti	Cape Verde	Central African Republic	Namibia
Eritrea	Côte d'Ivoire	Chad	South Africa
Ethiopia	Gambia	Congo	Swaziland
Kenya	Ghana	Democratic Republic of the Congo	
Madagascar	Guinea	Equatorial Guinea	
Malawi	Guinea-Bissau	Gabon	
Mauritius	Liberia	Sao Tome and Principe	
Mozambique	Mali		
Rwanda	Mauritania		
Seychelles	Niger		
Sudan	Nigeria		
Uganda	Senegal		
United Republic of Tanzania	Sierra Leone		
Zambia	Togo		
Zimbabwe			

Table A 1: Country classification for Sub-Saharan Africa

PROGRESS Model Inputs and Outputs

Model Inputs	Description
Renewable resource Potential	The total energy potential of each resource.
Scenario constraints	Accounts for future planned capacity reported in regional policy documents.
Demand	The annual electricity demand for the region, including exports.
Load Profile	Hourly demand profile for one day for the region. If this is not available, a representative profile is scaled to fit the demand of the region.
Peak Demand	The peak electricity demand in the region
Reserve Margin	The generation portfolio to meet a surplus of demand, usually at 15%.
Capital Cost	The capital cost of each generation technology over the planning horizon.
Operational Cost	The operating and maintenance cost of each technology over the planning horizon
Discount Rate	The rate at which the costs are discounted.

Table A 2: List of inputs for the PROGRESS model

Model Outputs	Description
Annual Generation Capacity Investment	The decision variable of the linear program, regarding megawatts. It refers to new generation capacity installed each year.
Hourly Dispatch	This is also a decision variable representing the amount of electricity generated from each resource in the sampled hours.
Total Generation Cost	Sum of annual generation cost that is discounted to net present value. It is the objective function of the linear program.

Table A 3: List of outputs for the PROGRESS model

Resources	PROGRESS	SWITCH
Solar PV	17%	0%
Wind	27%	25%
Biomass	0.1%	0%
Small Hydro RoR	0.3%	0%
Large Hydro	5%	3%
Coal	0%	0%
Natural Gas	21%	24%
Diesel	3%	17%
Geothermal	7%	32%

Table A 4: Generation mix of Kenya using PROGRESS and SWITCH models

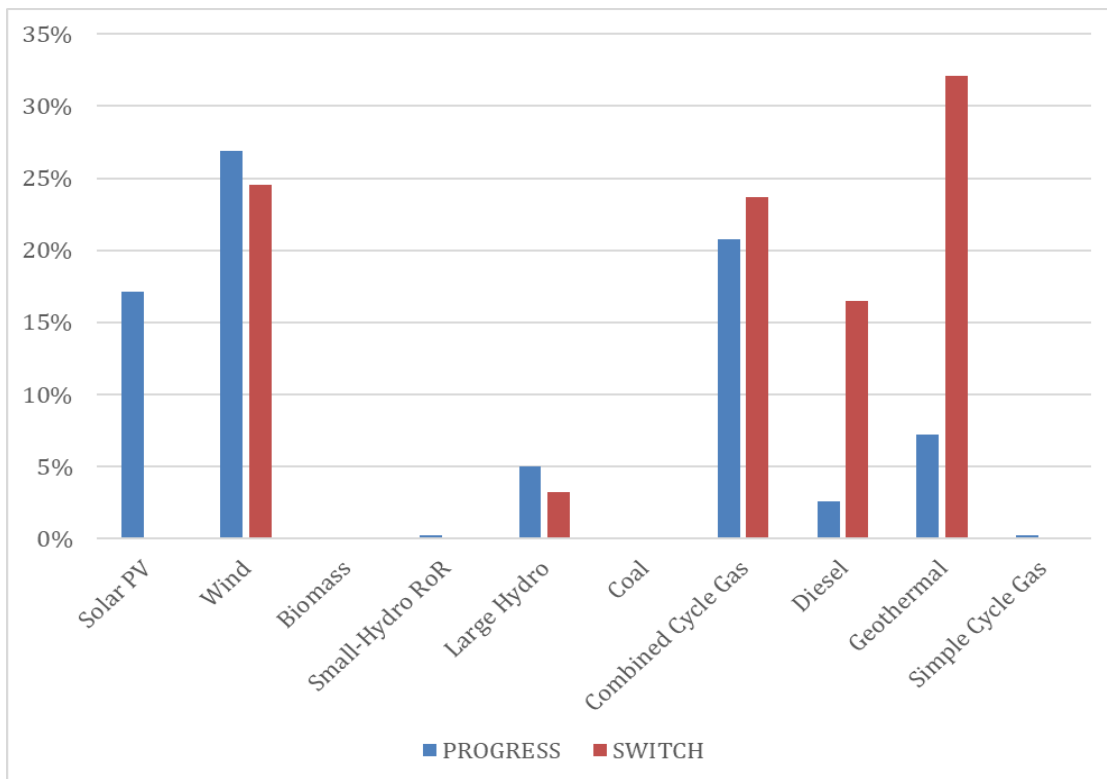


Figure A 1: Results from the PROGRESS model compared to published SWITCH-Kenya results.

PROGRESS Model ReadMe

PROGRESS: an electricity capacity expansion modeling tool
The PROGRESS model script takes one step to convert user input into a parsed, easy to read Excel file of calculated cost and electricity metrics. It runs on an iPython notebook, making it compatible with different potential user systems.

Getting Started

These instructions will lead you through how to use the system given an input Excel file.

Prerequisites

This is everything necessary to run the model, including Python version and packages. Install all of these using their respective websites or with pip. ``

```
python3  
openpyxl  
yaml  
GLPK solver  
pyomo  
ipython  
``
```

Getting the system running

First, ensure that all the attached files as well as your desired Excel input file are in the same directory. Navigate into the directory on terminal, and run the ipython notebook.

For Mac:

```
``
```

```
ipython notebook RunModel.ipynb  
``
```

For PC:

```
``
```

```
ipython notebook Run_Progress.ipynb  
``
```

After this, the notebook will come up on your default browser. Run each code block in succession; at the end, in the same directory, you will have a completed Excel output whose name you will specify within the notebook.

Model description

(include if necessary)

Navigating the files

The outermost level of the script is the ipython notebook; the two relevant files are RunModel.ipynb (which works consistently on Mac) and Run_Progress.ipynb (the version of the notebook required to run the model on PC). The notebook uses ParseData2.py to convert the input spreadsheet to the required data output format, of filetype .dat.

The .dat file is analyzed for some of the desired final metrics and outputted into a .yaml file in ProgressModel.py. Finally, the yaml file is converted to the final spreadsheet in

ParseOutput5.py, which both performs further calculations passed in from the yml file and formats all the data into a readable spreadsheet. NPV and LCOE calculations performed by an external Python module we wrote, housed in NPV_LCOE.py. This module is imported into ParseOutput5.

Navigating the outputs

The spreadsheet outputted by the final step of the above procedure is made up of several tabs. The first tab contains cost outputs, including capital cost, variable cost, average cost, O&M cost, and annual cost (total of capital, variable, and O&M) for each resource per year. Capital, variable, and O&M costs are passed into ParseOutput5 from the yml file as rates, so we calculate them to be in terms of dollars. Capital cost is passed in terms of \$/MW, so we multiply it by installed capacity to convert it to a cost. For capital cost, each year and each resource, we only multiply the newly installed capacity by that year's \$/MW rate before adding it to the previous year's capital cost for that resource; thus, each column's value is cumulative. Variable cost is similarly passed in as a \$/MWH quantity, so for each year and resource we multiply it by that year and resource's generation. Finally, the fixed O&M is passed in as a \$/MW-yr quantity, so we multiply it by the installed capacity. The average cost for each resource per year is calculated by dividing the total cost for that year by the capacity. The NPV and LCOE are calculated in the module described in the prior section. Finally, the yearly installation cost is all the yearly capital cost summed over all resources, yearly dispatch cost is the variable cost summed over all resources, and total cost is the annual cost summed over all resources.

The electricity outputs are on the next tab, and they include installed capacity (MW), generation (MWH), capacity factor (%), and annual load (MWH). The first two are passed in from the yml file and just formatted. Capacity factor is $\text{capacity}/(144 \text{ hrs} * \text{generation})$ converted into a percent. Annual load is the sum of hourly loads for each year.

The next tab contains the hourly loads (MWH), which are the loads sampled every four hours over 12 peak days and 12 average days for a total of 24 sampled days and 144 sampled hours (this is where the 144 to calculate capacity factor comes in).

Next is hourly generation, which functions like hourly load tab but contains generations instead of loads.

Finally, the next tab to the last tab are these hourly generations broken down for each resource.

Fixes

There are parts of the system that still require tweaking and fixing. The first of these is Mac/PC compatibility — ideally, RunModel.ipynb should work on both. The next important piece is fixing the cost outputs, detailed above. They do not match the values they should, even though the electricity outputs do match. Finally, once these fixes are implemented, we want to migrate the whole script to a web application to improve accessibility.

Table A 5: How to run the PROGRESS model

IPython Notebook Script

```
import pyomo.environ
from pyomo.opt import SolverFactory
opt = SolverFactory("glpk")
#!python -m pip install --upgrade pip
# excel_filename can be changed to the desired name of the final output file
excel_filename = "resultsMay28-apr20.xlsx"
%run ./ParseData2.py
!pyomo solve --solver="glpk" ProgressModel.py samplingfile.dat
yml_filename = "results.yml"
from ParseOutput5 import write_excel
yml_filename = "resultsApr20.yml" #name of the file in the computer directory
write_excel(yml_filename, excel_filename)
```

Table A 6: How to automate running the model scripts using the IPython Notebook

Linear Program Code

```
# Readme July 2018
# First, download and install Python3 via the Anaconda distribution:
https://conda.io/docs/user-guide/install/download.html
#
# Next, download Gnu's GLPK solver from https://www.gnu.org/software/glpk/
#
# Download pyomo from http://www.pyomo.org/installation/
#
# Move ProgressModel.py, ParseData.py, parseoutput_2.py, and CESATemplate v6 with
SWITCH.xlsx into the same directory
# From the terminal, run "python ParseData.py". This will parse data from the Excel file
into a usable .dat file, samplingfile.dat
#
```

```

# From the terminal, run "pyomo solve --solver='glpk' ProgressModel.py samplingfile.dat".
This tells Pyomo to solve our model on the specified data file using the GLPK solver
#
# The output file will default to being named "results.yml". Change this to the desired name
of the final spreadsheet, i.e. "resultsDec12"
# Then, open parseoutput_2.py and change the variable "input_filename" to this same
name, "resultsDec12.yml". Run "python parseoutput_2.py", and the
# results will be transferred to an Excel spreadsheet with the chosen name.
#
#####
#####

# Import libraries
from pyomo.environ import *
from pyomo.opt import SolverFactory
import pandas as pd
import yaml
import numpy as np
import matplotlib.pyplot as plt
import itertools

#####
#####

# Define model
# Run a single instance of the model from a file
def run_model(filename):

    ## Initialize model
    model = AbstractModel()

```

```
# Creating range for resources and year
# model.m = Param(within=NonNegativeIntegers)
# model.n = Param(within=NonNegativeIntegers)

# Index of resource
model.R = RangeSet(1, 15)

# Index of year
model.Y = RangeSet(1, 16)

# Index of day, 24 representative days per year
model.D = RangeSet(1, 24)

# Index of hour, 4 hour time periods each day
model.H = RangeSet(1, 6)

# Parameters for the model, taken from the .dat file
model.cap = Param(model.R, model.Y)
model.var = Param(model.R, model.Y)
model.hourly_load = Param(model.Y, model.D, model.H)
model.hourly_cf = Param(model.R, model.H)
model.set_use = Param(model.R)
model.min = Param(model.R)
model.max = Param(model.R)
model.om = Param(model.R, model.Y)

# # Load in data
```

```

# data = DataPortal()
# data.load(filename=filename,
param=(model.cap,model.var,model.hourly_load,model.hourly_cf,model.set_use,model.min,
model.max), format='param')

# print(data)

# Variables for the model
model.mw = Var(model.R*model.Y, domain=NonNegativeReals)
model.mwh = Var(model.R*model.Y * model.D * model.H,
domain=NonNegativeReals)
model.current_cost = Var(model.Y, domain=NonNegativeReals)
model.yearly_installation_cost = Var(model.Y, domain=NonNegativeReals)
model.annual_cost = Var(model.R, model.Y, domain=NonNegativeReals)
model.annual_var_cost = Var(model.R, model.Y, domain=NonNegativeReals)
model.annual_cap_cost = Var(model.R, model.Y, domain=NonNegativeReals)
model.annual_load = Var(model.Y, domain=NonNegativeReals)
model.hourly_load_output = Var(model.Y, model.D, model.H,
domain=NonNegativeReals)
model.cap_cost = Var(model.R, model.Y, domain=NonNegativeReals)
model.var_cost = Var(model.R, model.Y, domain=NonNegativeReals)
model.installation = Var(model.R*model.Y, domain=NonNegativeReals)

# Cost function to minimize
model.OBJ = Objective(rule=cost_rule, sense=minimize)

# Constraints for the model
model.installation_const = Constraint(model.R*model.Y, rule=installation_rule)
model.hourly_load_output_const = Constraint(model.Y*model.D*model.H,
rule=hourly_load_rule)
model.annual_load_const = Constraint(model.Y, rule=annual_load_rule)

```



```

model.cap_cost_const = Constraint(model.R*model.Y, rule=cap_cost_rule)
model.var_cost_const = Constraint(model.R*model.Y, rule=var_cost_rule)
model.curr_const = Constraint(model.Y, rule=current_cost_rule)
model.yearly_installation_cost_const = Constraint(model.Y,
rule=yearly_installation_cost_rule)
model.annual_cost_const = Constraint(model.R * model.Y, rule=annual_cost_rule)
#model.annual_var_cost_const = Constraint(model.R*model.Y,
rule=annual_var_cost_rule)
#model.annual_cap_cost_const = Constraint(model.R*model.Y,
rule=annual_cap_cost_rule)
model.growth_const = Constraint(model.R * model.Y, rule=growth_rule)
#model.reasonable_growth_constraint = Constraint(model.R * model.Y,
rule=reasonable_growth_rule)
model.capacity_const = Constraint(model.R * model.Y * model.D * model.H,
rule=capacity_rule)

model.hourly_load_const = Constraint(model.Y * model.D * model.H,
rule=hourly_load_met)
model.use_const = Constraint(model.R * model.Y * model.D * model.H,
rule=set_use_rule)
model.bounds = Constraint(model.R * model.Y, rule=bounds_rule)
model.large_hydro = Constraint(model.Y*model.D*model.H)
#model.reserve_margin_rule = Constraint(model.R*model.Y*model.D*model.H)
#model.reserve_margin_const = Constraint(model.Y * model.D,
rule=reserve_margin_rule_2)
model.resource_outage_const = Constraint(model.R*model.Y*model.D*model.H,
rule=resource_outage_rule)
model.profile_match_const = Constraint(model.R * model.Y * model.D * model.H,
rule=profile_match_rule)
model.coal_const = Constraint(model.R*model.Y*model.D*model.H,
rule=coal_capacity_factor)
model.geothermal_const_1 = Constraint(model.R*model.Y*model.D*model.H,

```

```

rule=geothermal_capacity_factor_1)
    model.geothermal_const_2 = Constraint(model.R*model.Y*model.D*model.H,
rule=geothermal_capacity_factor_2)
    # model.spill_constraint = Constraint(model.Y*model.D*model.H, rule=spill_rule)
    # model.peak_demand_const = Constraint(model.Y, rule=peak_demand_met)
    # model.cf_const = Constraint(model.R * model.Y * model.H, rule=cf_rule)
    # model.min_operations = Constraint(model.R * model.Y * model.H,
rule=min_operations_rule)
    # Run the model out return results
instance = model.create_instance(filename=filename)
stream_solver = True
opt = SolverFactory('glpk')
results = opt.solve(instance, tee=True)
return instance

## Objective function to be minimized: calculates total cost

#Objective function to be minimized: calculates total cost
def cost_rule(model):
    return sum(model.installation[i, j] * model.cap[i, j] \
                for (i, j) in model.R * model.Y) + sum(model.mwh[i, j, k, l] * 60.8 * model.var[i,
j] \
                for (i, j, k, l) in model.R * model.Y * model.D * model.H) + sum(model.mw[i, j]
* model.om[i, j] \
                for (i, j) in model.R*model.Y)

## Constraint functions

# Keep track of new installation in each year

```

```

def installation_rule(model, i, j):
    if j == 1:
        return model.installation[i, j] == model.mw[i, j] - model.min[i]
    else:
        return model.installation[i, j] == model.mw[i, j] - model.mw[i, j - 1]

#Constraint to keep track of hourly load as an output
def hourly_load_rule(model, j, k, l):
    return model.hourly_load_output[j, k, l] == model.hourly_load[j, k, l]

#Add output for total annual load
def annual_load_rule(model, j):
    return model.annual_load[j] == sum(60.8 * model.mwh[i, j, k, l] for (i, k, l) in
model.R*model.D*model.H)

def cap_cost_rule(model, i, j):
    return model.cap_cost[i, j] == model.cap[i, j]

def var_cost_rule(model, i, j):
    return model.var_cost[i, j] == model.var[i, j]

#Annual cost of total dispatch
def current_cost_rule(model, j):
    return model.current_cost[j] == sum(model.mwh[i, j, k, l] * model.var[i, j] for (i, k, l)
in model.R * model.D * model.H)

```

```

#Annual cost of total installation
def yearly_installation_cost_rule(model, j):
    if j == 1:
        cost = sum([(model.mw[i, j] - model.min[i]) * model.cap[i, j]] for i in model.R)
    else:
        cost = sum([(model.mw[i, j] - model.mw[i, j - 1]) * model.cap[i, j]] for i in
model.R)

return model.yearly_installation_cost[j] == cost

#Constraint to calculate the total cost per year per resource-does not affect objective
function
def annual_cost_rule(model, i, j):
    growth_cost = 0
    if j > 1:
        growth_cost += (model.mw[i, j] - model.mw[i, j-1]) * model.cap[i, j]
    return model.annual_cost[i, j] == sum(model.mwh[i, j, k, l] * model.var[i, j] for (k, l)
in model.D * model.H) + growth_cost

#return model.annual_cost[i, j] == growth_cost

#Constraint to calculate the total variable cost per resource per year
def annual_var_cost_rule(model, i, j):
    return model.annual_var_cost[i, j] == sum(model.mwh[i, j, k, l] * model.var[i, j] for
(k, l) in model.D*model.H)

#Constraint to calculate the total capital cost per resource per year
def annual_cap_cost_rule(model, i, j):
    growth_cost = 0
    if j > 1:

```

```

        growth_cost += (model.mw[i, j] - model.mw[i, j-1]) * model.cap[i, j]
    return model.annual_cap_cost[i, j] == growth_cost
#Constraint to make sure we aren't retiring capacity
def growth_rule(model, i, j):
    if j == 1:
        return Constraint.Skip
    return model.mw[i, j] >= model.mw[i, j - 1]

#Constraint to limit growth to reasonable levels
def reasonable_growth_rule(model, i, j):
    if j == 1:
        return model.mw[i, j] <= model.min[i] + 500
    else:
        increase = model.mw[i, j - 1] * .3
        upper_bound = increase
        return model.mw[i, j] <= upper_bound + model.mw[i, j - 1]

#Constraint to ensure we aren't exceeding our production capacity
def capacity_rule(model, i, j, k, l):
    #return model.mw[i, j] * .85 >= model.mwh[i, j, k, l]
    return model.mw[i, j] >= model.mwh[i, j, k, l]

#Inequality constraint to ensure hourly load is met
def hourly_load_met(model, j, k, l):
    hour = sum(model.mwh[i, j, k, l] for i in model.R)
    return hour == model.hourly_load[j, k, l]

```

```

#Change to setting percentage of total power capacity/generation
def set_use_rule(model, i, j, k, l):
    return model.mwh[i, j, k, l] <= model.set_use[i] * model.mw[i, j]

#Constraint to ensure our capacity is within the given bounds-can't retire resources
#and can't exceed resource potential
def bounds_rule(model, i, j):
    return (model.min[i], model.mw[i, j], model.max[i])

#Constraint to keep large hydro generating at 60% of its capacity
def large_hydro_budget_rule(model, j, k):
    if k > 12:
        return Constraint.Skip
    else:
        return sum(model.mwh[5, j, k, l] for l in model.H) == 6 * 0.6*model.mw[5, j]

#Reserve margin constraint: total generation (across all resources) in each hour can't
exceed 90% of the total capacity in that hour
def reserve_margin_rule(model, j, k, l):
    hourly_capacity = sum(model.mw[i, j] for i in model.R)
    return hourly_capacity* 0.9 >= model.hourly_load[j, k, l]

# Forced outage: generation for each resource in an hour can't exceed 90% of that
resource's capacity in each hour
def resource_outage_rule(model, i, j, k, l):
    return model.mw[i, j] * 0.9 >= model.mwh[i, j, k, l]

```

```

#Reserve margin constraint using peak of day
def reserve_margin_rule_2(model, j, k):
    hourly_capacity = sum(model.mw[i, j] for i in model.R) - model.mw[1, j]
    max_load = max(model.hourly_load[j, k, l] for l in model.H)
    return hourly_capacity >= max_load * 1.15

#Turned off April 13

#Constraint to ensure non-dispatchable resources match their profiles exactly
def profile_match_rule(model, i, j, k, l):
    if i == 1 or i == 2 or i==4:
        return model.mwh[i, j, k, l] == model.hourly_cf[i, l] * model.mw[i, j]
    return Constraint.Feasible

#Geothermal and coal generation should be same each day of each year
def coal_capacity_factor(model, i, j, k, l):
    if (i == 6 or i == 3) and l < 6:
        return model.mwh[i, j, k, l] == model.mwh[i, j, k, l+1]
    else:
        return Constraint.Skip

def geothermal_capacity_factor_1(model, i, j, k, l):
    if k == 24 or l == 6:
        return Constraint.Skip
    if i == 9:
        return model.mwh[i, j, k, l] == model.mwh[i, j, k+1, l]

```

```

else:
    return Constraint.Skip

def geothermal_capacity_factor_2(model, i, j, k, l):
    if k == 24 or l == 6:
        return Constraint.Skip
    if i == 9:
        return model.mwh[i, j, k, l] == model.mwh[i, j, k, l+1]
    else:
        return Constraint.Skip

#def spill_rule(model, j, k):
#    return sum(model.mwh[i, j, k, l] for (i, l) in model.R*model.H) <= 1.15 *
#    sum(model.hourly_load[j, k, l] for l in model.H)

def spill_rule(model, j, k, l):
    return sum(model.mwh[i, j, k, l] for i in model.R) <= 1.1 * model.hourly_load[j, k, l]

#Unused constraints:

def peak_demand_met(model, j):
    day = sum(model.mw[i, j] for i in model.R)
    return day >= 1.15 * model.peak_demand[j]

```



```

def cf_rule(model, i, j, k):
    return model.mwh[i, j, k] <= model.hourly_cf[i, k] * model.mw[i, j]
def min_operations_rule(model, i, j, k):
    return model.mwh[i, j, k] >= 0.1 * model.mw[i, j] * model.hourly_cf[i, k]

#####
#####

# Utility functions
# Function parsing a Param or Var into a dataframe for plotting
def pyomo_to_df(obj):
    pd.set_option('display.multi_sparse', False)
    names = {'mw':['Resource','Year'],
             'mwh':['Resource','Year','Day','Hour'],
             'current_cost':['Year'],
             'yearly_installation_cost':['Year'],
             'annual_cost':['Resource','Year'],
             'annual_var_cost':['Resource','Year'],
             'annual_cap_cost':['Resource','Year'],
             'annual_load':['Year'],
             'hourly_load_output':['Year','Day','Hour'],
             'cap_cost':['Resource','Year'],
             'var_cost':['Resource','Year'],

             'installation':['Resource','Year'],
             'cap':['Resource','Year'],
             'var':['Resource','Year'],

```

```

        'hourly_load':['Year','Day','Hour'],
'hourly_cf':['Resource','Hour'],
        'set_use':['Resource'],
        'min':['Resource'],
        'max':['Resource'],
        'om':['Resource','Year']}

iteritems = obj.iteritems()
keys = []
vals = []
# print(type(obj) == pyomo.core.base.param.IndexedParam)
if type(obj) == pyomo.core.base.var.IndexedVar:
    for i in iteritems:
        keys.append(i[0])
        vals.append(i[1].value)
elif type(obj) == pyomo.core.base.param.IndexedParam:
    for i in iteritems:
        keys.append(i[0])
        vals.append(i[1])
if type(keys[0]) == tuple:
    mult_index = pd.MultiIndex.from_tuples(keys,names=names[obj.name])
    df = pd.DataFrame(index=mult_index,data=vals,columns=[obj.name])
else: df = pd.DataFrame(index=keys,data=vals,columns=[obj.name])
return df

# def df_stackplot(df,vbl,filt=False,extend=True,percent=False):
#     if not filt:
#         df = df.unstack(vbl)
#         print(df)

```

```

#     else:
#         df = df.unstack(vbl).xs(filt[0],level=filt[1])
#         print(df)
#     if extend:
#         df = df.append(df.loc(df.index.values[0]),ignore_index=True)
#         print(df)
#     if percent:
#         df = df.divide(df.sum(axis=1),axis=0)
#         print(df)
#     plt.stackplot(df.index.values,df.values.T,labels=df.columns)
#     plt.legend(loc='center left',bbox_to_anchor=(1, 0.5))
#     plt.show()

def df_stackplot(df,figsize=[15,5],xlabel="",ylabel="",title="):
    df = df.round(2)
    df = df.loc[:, (df != 0).any(axis=0)]
    df = df.reindex_axis(df.mean().sort_values(ascending=False).index, axis=1)
    plt.figure(figsize=figsize)
    plt.stackplot(df.index.values,df.values.T,labels=df.columns)
    plt.legend(loc='center left',bbox_to_anchor=(1, 0.5))
    plt.xlabel(xlabel)

plt.ylabel(ylabel)
    plt.title(title)
    plt.grid()
    plt.show()

def df_lineplot(df,figsize=[15,5],xlabel="",ylabel="",title="):

```

```
df = df.round(2)
df = df.reindex_axis(df.mean().sort_values(ascending=False).index, axis=1)
df = df.loc[:, (df != 0).any(axis=0)]
df.plot(figsize=figsize)
plt.legend(loc='center left',bbox_to_anchor=(1, 0.5))
plt.xlabel(xlabel)
plt.ylabel(ylabel)
plt.title(title)
plt.grid()
plt.show()
```

```
def build_Param(index, values):
    dic = dict(zip(index, values))
    return Param(dic.keys(), initialize=dic)
```

Parsing input data in .dat files

```
from openpyxl import load_workbook

import numpy as np

# Readme:

# Change filename below to the name of your Excel workbook. From the terminal, make sure both
this file and
# your workbook are in the same directory, and run "python ParseData.py"

wb1 = load_workbook(filename = "InputData.xlsx", data_only=True)
ws1 = wb1["Potential and Cost"]

#Defining hours of each day to be sampled
#hours = [1, 5, 9, 13, 17, 21]
hours = [0, 4, 8, 12, 16, 20]

open_file = open("samplingfile.dat", 'w')
#Setting number of resources
open_file.write("param m := 15 ;")
open_file.write("\n")
#Add capital costs to file
resource = 0
year = 0

#Parsing minimum (initial) capacity
open_file.write("param min := ")
```

```

for cell in ws1['C3':'C12']:
    resource += 1
    open_file.write(" ")
    open_file.write(str(resource))
    open_file.write(" ")
    open_file.write(str(cell[0].value))
#Adding minimum capacity for unused future resources
for i in range(0, 5):
    resource += 1
    open_file.write(" ")
    open_file.write(str(resource))
    open_file.write(" ")
    open_file.write(" ")
    open_file.write("0")
    open_file.write(" ")
resource = 0
open_file.write("\n" + ";" + '\n')

#Parsing maximum capacity
open_file.write("param max := ")

for cell in ws1['B3':'B12']:
    resource += 1
    open_file.write(" ")
    open_file.write(str(resource))
    open_file.write(" ")
    open_file.write(str(cell[0].value))

```

```

open_file.write(" ")
for i in range(0, 5):
    resource += 1
    open_file.write(str(resource))
    open_file.write(" ")
    open_file.write(" ")
    open_file.write("0")
    open_file.write(" ")
resource = 0
open_file.write("\n" + ";" + '\n')

#Parsing capital costs
open_file.write("param cap := ")

for col in ws1.iter_cols(min_row = 45, min_col = 8, max_row = 54):
    year += 1
    for cell in col:
        resource += 1
        open_file.write(str(resource))
        open_file.write(" ")
        open_file.write(str(year))
        open_file.write(" ")
        val = str(cell.value or 0)
        open_file.write(val)
        open_file.write(" ")
    for i in range(0, 5):
        resource += 1

```

```

        open_file.write(str(resource))
        open_file.write(" ")
        open_file.write(str(year))
        open_file.write(" ")
        open_file.write("0")
        open_file.write(" ")

    resource = 0
open_file.write("\n" + ";" + '\n')
open_file.write("")

#Parsing capital costs
open_file.write("param om := ")

year = 0

for col in ws1.iter_cols(min_row = 71, min_col = 8, max_row = 80):
    year += 1
    for cell in col:
        resource += 1
        open_file.write(str(resource))
        open_file.write(" ")
        open_file.write(str(year))
        open_file.write(" ")
        val = str(cell.value or 0)
        open_file.write(val)
        open_file.write(" ")
    for i in range(0, 5):
        resource += 1

```



```

        open_file.write(str(resource))
        open_file.write(" ")
        open_file.write(str(year))
        open_file.write(" ")
        open_file.write("0")
        open_file.write(" ")

    resource = 0
open_file.write("\n" + ";" + '\n')
open_file.write("")

#Setting number of years (previously counted by keeping track using year variable)
resource = 0
num_years = 16
open_file.write("param n := " + str(num_years))
open_file.write("\n" + ";" + '\n')

#Setting variable costs for each resource in each year
open_file.write("param var := ")
open_file.write(" ")
year = 0
for col in ws1.iter_cols(min_row = 58, min_col = 8, max_row = 67):
    year += 1
    for cell in col:
        resource += 1
        open_file.write(str(resource))
        open_file.write(" ")
        open_file.write(str(year))
        open_file.write(" ")

```

```

        val = str(cell.value)
        open_file.write(val)
        open_file.write(" ")

    for i in range(0, 5):
        resource += 1
        open_file.write(str(resource))
        open_file.write(" ")
        open_file.write(str(year))
        open_file.write(" ")
        open_file.write("0")
        open_file.write(" ")
    resource = 0

#Opening next page in workbook
ws2 = wb1["SWITCH load for a day"]
open_file.write("\n" + ";" + "\n")

ws4 = wb1["RE profiles"]

#Setting capacity factors
open_file.write("param hourly_cf := ")
open_file.write('\n')
count = 0
hours1 = ws4["F2":"F25"]
hours2 = ws4["G2":"G25"]
i = 0
for count in hours:

```

```

pass
i += 1
open_file.write("1 ")
open_file.write(str(i) + " ")
open_file.write(str((hours2[count - 1])[0].value / (547 * 1.0)))
open_file.write(" 2 ")
open_file.write(str(i) + " ")
open_file.write(str((hours1[count - 1])[0].value * 2 / (10293 * 1.0)))
open_file.write(" ")
open_file.write(" 4 ")
open_file.write(str(i) + " ")
open_file.write(str((hours1[count - 1])[0].value * 2 / (10293 * 1.0)))
open_file.write(" ")
open_file.write("9 ")
open_file.write(str(i) + " ")
open_file.write("0.5 ")
for j in range(3, 16):
    if j != 4 and j != 9:
        open_file.write(str(j) + " ")
        open_file.write(str(i) + " ")
        open_file.write("1 ")

open_file.write("\n" + ";" + "\n")

#Setting hourly load for both average and peak day
open_file.write("param hourly_load := \n")

increases = ws2["D2" : "X2"]

```

```

real_increases = increases[0]

year = 0
loads = ws2["B5":"B28"]
multipliers = ws2["G5":"G25"]

for year in range(1, num_years + 1):
    for day in range(12):
        i = 1
        for hour in hours:
            open_file.write(str(year) + " ")
            open_file.write(str(day + 1) + " ")
            open_file.write(str(i) + " ")
            open_file.write(str(loads[hour][0].value * multipliers[year - 1][0].value))
            open_file.write(" ")
            i += 1

peaksws = wb1["SWITCH Peak Day"]
peak_loads = peaksws["C2": "C25"]
peak_multipliers = peaksws["H2": "H22"]
for year in range(1, num_years + 1):
    for day in range(12, 24):
        i = 1
        for hour in hours:
            open_file.write(str(year) + " ")
            open_file.write(str(day + 1) + " ")
            open_file.write(str(i) + " ")
            open_file.write(str(peak_loads[hour][0].value * peak_multipliers[year -
1][0].value))

```

```
        open_file.write(" ")
        i += 1

open_file.write("\n" + ";" + "\n")
open_file.write("param set_use := \n")
for i in range(1, 11):
    open_file.write(str(i) + " ")
    open_file.write("1" + " ")
for i in range(11, 16):
    open_file.write(str(i) + " ")
    open_file.write("0" + " ")
open_file.write("\n" + ";" + "\n")

open_file.close()
```

Table A 7: The python script for the PROGRESS model