

Côte d'Ivoire's Electricity Challenge in 2050: Reconciling Economic Development and Climate Commitments

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Côte d'Ivoire's Electricity Challenge in 2050: Reconciling Economic Development and Climate Commitments

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Résumé

En comblant son écart économique avec les marchés émergents, la Côte d'Ivoire sera confrontée à une augmentation substantielle de la demande d'électricité au cours des trois prochaines décennies. La Côte d'Ivoire a signé l'Accord de Paris qui vise à atteindre un équilibre entre les émissions anthropiques par les sources, dont l'électricité, et l'absorption par les puits de gaz à effet de serre dans la seconde moitié du siècle. Cet article développe un outil prospectif pour explorer les chemins d'investissement dans les technologies de l'électricité compatibles à la fois avec une demande d'électricité en croissance rapide et avec l'Accord de Paris. Nous construisons un modèle TIMES pour la Côte d'Ivoire et exécutons des scénarios avec deux ensembles d'hypothèses raisonnables qui représentent deux visions concurrentes et probables des coûts futurs des technologies du charbon et du photovoltaïque. Les résultats montrent qu'une taxe carbone d'environ 21 dollars américains en 2035 et 82 dollars américains en 2050 sur la production d'électricité garantira une production d'électricité à faible émission de carbone conforme à l'accord de Paris. Bien qu'un mix énergétique à faible émission de carbone

permette de créer beaucoup plus d'emplois, les deux principaux défis à relever pour parvenir à ce mix énergétique seront d'installer jusqu'à 24 GW d'énergie photovoltaïque d'ici 2050 ou de parvenir à une taxe carbone socialement acceptée.

Mots-clés: Prix du carbone ; électricité ; Côte d'Ivoire ; Accord de Paris ; solaire ; charbon.

Abstract

In closing its economic gap with emerging markets, Côte d'Ivoire will face a substantial increase in electricity demand over the next three decades. Côte d'Ivoire has signed the Paris Agreement that aims to achieve a balance between anthropogenic emissions by sources, including electricity, and absorption by sinks of greenhouse gases in the second half of the century. This paper develops a forward-looking tool to explore electricity technology investment paths compatible with both rapidly increasing electricity demand and the Paris Agreement. We build a TIMES model for Côte d'Ivoire and run scenarios with two sets of reasonable assumptions that represent two competing and probable visions of the future costs of coal and photovoltaic technologies. The results show that a carbon tax of about US\$21 in 2035 and US\$82 in 2050 on electricity generation will ensure low-carbon electricity gener-

ation in line with the Paris Agreement. Although a low-carbon energy mix would create significantly more jobs, the two main challenges in achieving this energy mix will be to install as much as 24 GW of photovoltaic power by 2050 or to achieve a socially accepted carbon tax.

Keywords: Climate finance regulation; capital requirements; Green Supporting Factor; climate adaptation.

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1. Introduction

Like many developing countries, Côte d'Ivoire suffers from a lack of electricity infrastructure. The development of this sector is one of the country's main priorities in order to achieve political objectives such as universal access to electricity and economic development. Between 2000 and 2018, the installed electrical capacity almost doubled from 1.2 GW (50% hydropower and 50% thermal energy) to 2.2 GW (40% hydropower and 60% thermal energy). In the same period, annual consumption *per capita* went from 174 KWh to 277 KWh (AIE, 2014; ANARE-CI, 2017). However, as of 2014, *per capita* consumption in Côte d'Ivoire is 43% lower than the average for sub-Saharan Africa and 91% lower than the world average.

Frequently updated ten-year electricity sector master plans (WAPP, 2011, 2018; ANARE-CI, 2017) and available forecast (IRENA, 2013, 2018) focus on a 2030–2035 time horizon. IEA (2019) provides two electricity mixes up to 2040 but with few details. According to WAPP (2018), the planned capacity is expected to increase by 1,880 MW in 2030, of which 37% would be coal-fired power plants and only 5.3% would be photovoltaic solar power plants. This development mimics China's emerging strategy in the early 2000s. However, the current context is different in four respects. First, Côte d'Ivoire's natural endowment of inputs for coal-fired power plants is negligible, making the country dependent on imported resources. Second, as highlighted in Diallo and Moussa (2020), Côte d'Ivoire's high natural endowment of solar radiation enables the country to reduce the cost of solar technology compared to the rest of the world, including China. Moreover, the authors show that this advantage makes the solar home system a viable option for rural electrification in Côte d'Ivoire. Third, unlike in the 2000s, the current costs of renewable energy and its prospects are competitive. Fourth, the fight against climate change has become a top priority at the international level. For these reasons, this paper will pay particular attention to coal and solar energy technologies.

African Development Bank (2011) projections show that long-term real GDP growth in West Africa, including Côte d'Ivoire, could exceed 4.6% over the period 2020–2050 and reach 8.8% in the 2020s. These high real GDP growth projections are fairly consistent with the International Monetary Fund (2019)'s short-term projections, which range from 7.3% in 2020 to 6.4% in 2023.¹ In addition, the population size will almost double from 26 million to 51 million according to the medium fertility variant of the United Nations (2019)'s projections. Both real GDP and prospects for population growth will significantly boost electricity demand over the next three decades, and beyond.

In 2015, the African Union Commission (AUC), of which Côte d'Ivoire is a member state, issued Agenda 2063 (2015). This publication calls on AUC member states to act with a sense of urgency on climate change and the environment by participating in global efforts to mitigate climate change. In addition, Côte d'Ivoire ratified the Paris Agreement in 2015, which crystallized its commitment to climate action. According to its National Determined Contribution (NDC) of 2015, the share of green energy in the electricity mix is expected to reach 42% and greenhouse gas (GHG) emissions from this sector are not expected to

¹In the midst of the Covid-19 crisis, Côte d'Ivoire's latest real GDP growth projection, according to the IMF's World Economic Outlook at the time of writing this paper, is 1.8 percent. For the remainder, we are ignoring the long-term economic consequences of this crisis because they are uncertain.

exceed 9.2 Gt of CO₂eq in 2030.² To date, Côte d'Ivoire has not made any other quantitative commitment beyond 2030. This document aims to highlight public policy actions to align the two challenges: a substantial long-term increase in electricity demand and a low-carbon economy.

The set of investment decisions that a public planner faces in a given circumstance is limited by the decisions that previous officials made. This situation of path dependency is particularly true for the electricity sector, where the life of investments can be as long as 35 to 40 years, i.e. a supercritical coal-fired power plants. These sustainable technologies require generations of highly skilled engineers, specialized in the operation of particular technologies. Potential technological and human bottlenecks could be obstacles to achieving specific goals such as climate commitments. Therefore, it becomes essential to balance short-term decisions with a long-term perspective to address the challenges of sustainable development.

In order to reconcile the above-mentioned horizons and challenges, we have built and calibrated *The MARKAL-EFOM integrated system* (TIMES) for Côte d'Ivoire. This energy planning model selects an optimal mix of technologies to meet a given demand at minimum cost. To our knowledge, this is the first time this model has been applied specifically to Côte d'Ivoire. The main arguments for and against our choice of a technology-oriented model are as follow. TIMES is a bottom-up modeling approach of the energy system, and such models have well-known limitations.³ Yet technology choices are critical when it comes to energy systems, and bottom-up models offer unique insights into the articulation and competition between existing and future technologies that cannot be adequately captured by an analysis of past trends. Furthermore, optimization models do not predict the future of a system, but they do offer the ability to evaluate how a given technology pathway can be ideally adapted to meet new constraints.

This paper adopts a scenario approach to assess future transformations of the Côte d'Ivoire's power system. We develop scenarios using two sets of reasonable assumptions that represent two competing visions of future costs, particularly for coal and photovoltaic technologies. We also apply environmental restrictions to assess the socio-economic challenges of the power sector in Côte d'Ivoire to meet the long-term climate commitment. We then complete our forward-looking assessment with a sensitivity analysis for selected parameters.

The rest of this paper is organized as follows. Section 2 presents the model and its assumptions, Section 3 discusses the scenarios and the results, Section 4 presents a sensitivity analysis of our results, and Section 5 concludes.

²In 2012, the CO₂eq emissions from electricity generation in Côte d'Ivoire were 3.5 Gt CO₂eq.

³For example, they do not model the global macroeconomic environment, they only partially capture the international context and financial mechanisms (through import prices and discount rates), and they assume a globally optimized system.

2. Model and Assumptions

The objective of our analysis is to assess the conditions under which an energy system meets both a fast-growing demand and a low-carbon electricity mix in Côte d'Ivoire. To achieve this objective, we build a bottom-up TIMES model for the country's electricity system, hereafter called TIMES-CI-ELC.

The TIMES-CI-ELC modeling paradigm describes a family of energy systems models that has been developed under the Energy Technology Systems Analysis Programme (ETSAP) agreement of the International Energy Agency (IEA). TIMES models constitute a family of bottom-up energy system optimization models that have been widely used to assess future energy transition pathways for various geographical scales (Ortega et al., 2020; Assoumou and Maïzi, 2011; Amorim et al., 2020; Rehman et al., 2019; Dioha and Kumar, 2020; Millot et al., 2020). All TIMES models share two fundamental and common characteristics: first, a representation of the energy system as a linear combination of process and product candidates; and second, a minimization of the total discounted costs of the described system (topology and constraints) to define a least cost investment and operation path.

A detailed documentation presenting the structure and equations of the TIMES model generator is available in Loulou et al. (2016). We briefly present the main principles in this paper.

A simplified description of the objective function is given by eqs (1) and (2), as follows:

$$\min z = \sum_{y \in Years} \sum_{c \in Commodities} \sum_{p \in Processus} \frac{AnnCost(y, c, p)}{(1 + drate)^{y - startyear}}; \quad (1)$$

with

$$\begin{aligned} AnnCost(y, c, p) = & InvCost(y, p) + FixCost(y, p) + VarCost(y, p) + TaxSub(y, c, p) \\ & + ElasCost(y, c) + CostDecom(y, p) - Salvage(y, p). \end{aligned} \quad (2)$$

Where $drate$ is the discount rate; $InvCost(y, p)$ is the investment cost function for the process p in the year y ; $FixCost(y, p)$ is the fixed operation and maintenance cost function for the process p in the year y ; $VarCost(y, p)$ is the variable cost and maintenance cost function for the process p in the year y ; $TaxSub(y, p, c)$ is the taxes paid or subsidies received for the production of a commodity c or for an investment of a process p in the year y ; $ElasCost(y, c)$ is the economic loss associated to endogenous adjustment of demand commodities c in the year y when price elasticities of demands are provided;⁴ $CostDecom(y, p)$ if the cost function of dismantling the process p in the year y ; $Salvage(y, p)$ is the residual operative investments beyond the stopping time of the study of process p in the year y .

The output of the model then yields the optimal set of processes and products that minimizes the discounted intertemporal cost of the modeled energy system subject to demand satisfaction and user-defined constraints. In this paper, we use the TIMES-CI-ELC model to evaluate potential future power supply choices for Côte d'Ivoire and to highlight the

⁴The current version of the model does not include this feature as it requires specific studies on the price elasticities of electricity demand in Côte d'Ivoire. These aspects are left for further research.

interactions between technical choices and emission targets up to 2050 with a time step of five years.

The TIMES-CI-ELC model is organized around three interconnected modules (Figure 1) that successively describe the candidate paths for the supply of primary energy sources, the competition between electricity supply options, and the final electricity demands that must be met.

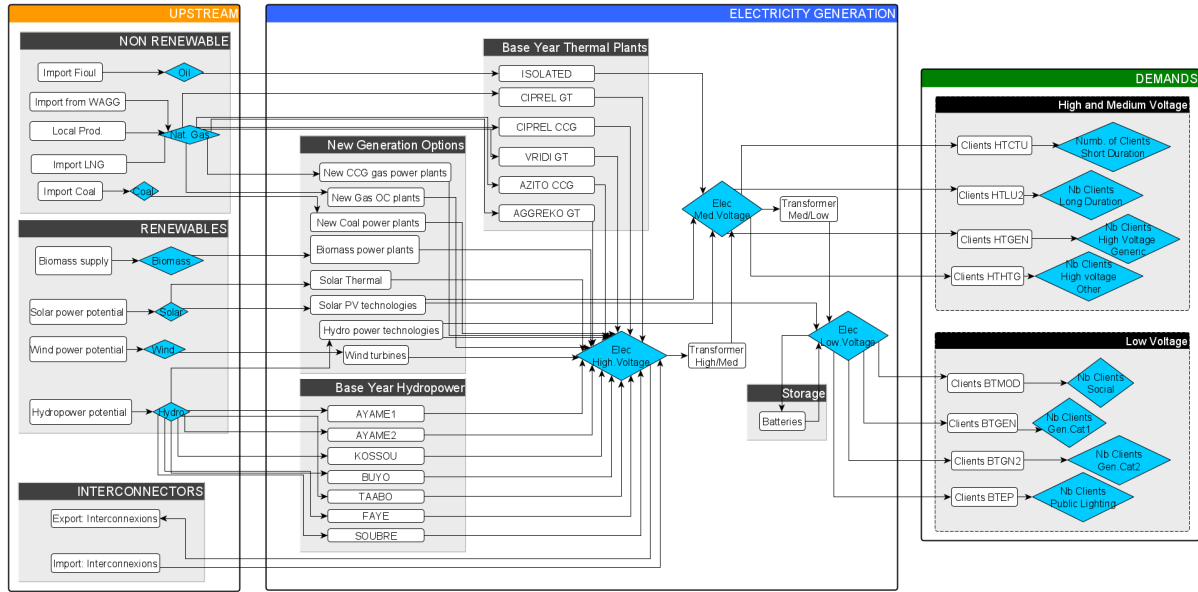


Fig. 1. Topology of the TIMES-CI-ELC model

In this paper, we are analyzing the future power system of Côte d'Ivoire for the period 2016–2050, divided into five-year periods to account for the decommissioning rate and the inertia associated with the lifetime of each technology. In addition, the temporal resolution for each period is refined by considering four typical days with a resolution of 24 hours. We consider an average day and three critical days for which the reduced availability of renewable sources can be simulated. This refinement allows us to obtain a more detailed description of the intraday production models and in particular of the variability of the intraday solar radiation (see Section 2.2.4 for further details). Finally, we use a 10% discount rate, which is standard for this literature.

2.1. Upstream module: primary energy sources and their costs

2.1.1. Topology of modelled energy technologies

As natural gas is the main source of electricity production in Côte d'Ivoire to date, we pay particular attention to its modeling. Its supply comes either from national gas reserves, via the West Africa Sub-Regional Gas Pipeline (WAGP), or from international gas reserves in the form of liquefied natural gas (LNG). According to CIA (2020); Foxtrot international (2007); IEA (2020), Côte d'Ivoire has 28.32 billion cubic meters of remaining gas reserves located in the southern part of the country. Most of this gas is used by the electricity sector. However, at the current

rate of exploitation, the existing gas deposits could be exhausted by 2030. Although Côte d'Ivoire is intensifying its exploration efforts, no new discoveries have been made in recent years. We assume that there will be no new local discoveries in the coming decades.

In addition to local resources, the upstream module includes a possible supply of natural gas through the WAGP. The WAGP is a 678 km long transnational natural gas infrastructure that links Nigeria to Ghana and supplies natural gas to power plants in Togo, Benin, and Ghana. An extension of this pipeline to Côte d'Ivoire is being discussed within the framework of regional integration initiatives (WAPP, 2018). Natural gas import from the WAGP is therefore included in the model.

Finally, natural gas can also be supplied by LNG carriers and regasification facilities. Paradoxically, the development of the WAGP and the difficulties observed in supplying the contractually agreed quantity of gas have favored the development of LNG to mitigate the supply risk. Kumi (2017); Fulwood and Bros (2018) discuss this supply risk for Ghana. Plans for future LNG supply to Côte d'Ivoire are materialized by the creation of the Côte d'Ivoire LNG consortium led by Total, which has been awarded a 3 million tons regasification project in 2016. In the model, primary supply of natural gas can then be extended if needed using LNG imports as a technical option.

Additionally to natural gas, other import processes to Côte d'Ivoire from international markets include oil and eventually coal. Indeed, to reduce its dependence on natural gas, Côte d'Ivoire is exploring the option of coal as an energy source (WAPP, 2018). The country's natural endowment of coal is scarce, forcing its coal supply strategy to rely on dedicated maritime infrastructure. To date, a project for a coal import terminal located in San-Pedro is underway, which aims to expand the existing port. Coal import is also included as an additional supply option for the future power mix.

Moreover, the upstream module also distinctly describes the primary supply potential of four renewable resources: hydropower, solar, wind, and biomass. In the case of these supply technologies, the model sets the maximum production potential provided by (IRENA, 2018).

Finally, options for electricity transfers with neighbouring countries are included in the model as import and export options at exogenous specified prices. Côte d'Ivoire is the third largest electricity market in West Africa and has historically been a net exporter of electricity with 11.8% of its total electricity generation sold to Mali, Burkina Faso, and Ghana in 2019 (ANARE-CI, 2020).

2.1.2. Future cost assumptions

Figure 2 presents the long-term cost assumption for our analysis. For the long-term evolution of oil, coal, and local natural gas sources, we retain the assumptions made for the 2018 update of the West African Power Pool (WAPP) master plan, WAPP (2018). These supply costs are kept constant beyond 2030. For natural gas imports from WAGP or supplied by LNG facilities, we use the long-term value estimated by Santley et al. (2014) for several areas of the African natural gas market. For Côte d'Ivoire, the cost of delivered gas has been estimated at between \$9 and \$11/MMBtu if supplied by the WAGP extension and between \$10 and \$12.7/MMBtu for

LNG based on assumptions on the degree of international price convergence. We assume an evolution of \$9 to \$10/MMBtu for WAGP and a constant value of \$12/MMBtu for LNG.

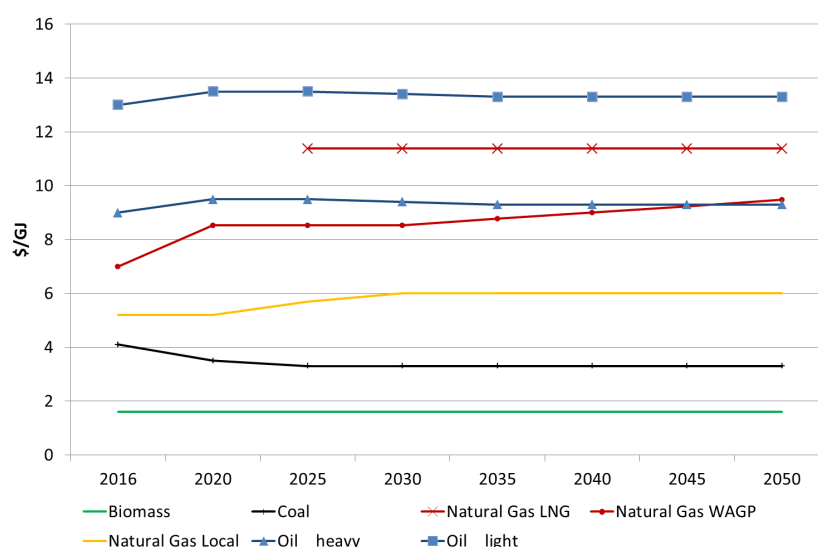


Fig. 2. Future fuel price projection in constant \$ per GJ for the period 2016–2050

One of the main challenges faced by the WAGP has been the recurring shortfall in the supply of contracted volumes of natural gas. Ghana has been WAGP’s main buyer of natural gas and its past delivery problems are reported in Kumi (2017); Fulwood and Bros (2018). For our analysis, the supply from Nigeria to Côte d’Ivoire after the extension of the WAGP has an upper limit. We assume that delivery to Côte d’Ivoire will not exceed the current contract volume with Ghana until 2035, at 133MMscf per day. For the second half of our simulation horizon, we assume as an upper limit a doubling of this level by 2050 (233MMscf per day). A linear interpolation between these target years is presented in Table 1. Additionally, WAPP (2018)

Upper bound MMscf per day	2025	2030	2035	2040	2045	2050
WAGP extension Takoradi–Abidjan	67	100	133	177	222	266

Table 1: Future upper bound for gas supply from WAGP

uses a biomass mobilization cost (default assumption) of less than \$2/GJ and a price of the fuel delivered of \$3.5/GJ. This order of magnitude is consistent with the value of \$1.6/GJ retained by IRENA (2018) for the update of its 2030 scenario for West Africa. We retain a default value of 1.6\$/GJ for resource mobilization and an additional cost of 1.9\$/GJ for delivery. For coal we assume a representative delivery cost of 50\$/t based on Bove et al. (2018).

2.2. Power generation module: competing power generation options and their costs

2.2.1. Topology: Competing power generation landscape

Planning to meet demand will require investment decisions at specific points in time. TIMES-CI-ELC is an intertemporal optimization model whose strength is to calculate coherent investment portfolios over several periods. Competing power generation options in Côte d'Ivoire are modeled in the "Power Generation Module".

The path dependency, i.e. the composition of the electrical mix at a given date, is the sum of past choices, and the inertia of the system is taken into account via the commissioning date and the lifetime of each plant. Electrical losses when the electricity produced is transmitted to the consumption sectors via the transmission and distribution networks are modeled using the transmission efficiencies. For each network level, the overall transmission efficiency calibrated for TIMES-CI-ELC, is 78.9% with 98.5% efficiency for high voltage, 92.3% for medium voltage, and 86.8% for low voltage (ANARE-CI, 2017).

The current production options are represented by the blocks titled Reference Year with existing thermal power plants (CIPREL GT, CIPREL CCG, VRIDI GT, AZITO CCG, AGGREKO GT, and Isolated) as well as hydroelectric power plants (AYAME 1, AYAME 2, KOSSOU, BUYO, TAABO, FAYE, and SOUBRE). Future technology options are listed by type of fuel input into the basket of technology options (gas, coal, biomass, solar, storage). Finally, high-voltage electricity can be exchanged via interconnections.

2.2.2. Projected future capacities

Table 2 presents the expansion plans that have been decided for the 2018 update of the WAPP Master Plan. Although the project timelines are not the same, these plants have already undergone a preliminary assessment of political, technological, and financial feasibility. It can be observed that for the near future, very few solar energy projects have been appraised, and that natural gas and hydropower plants constitute the majority of the projects decided upon. To take into account these projected plants, they are incorporated in the model as a lower bound for new investment.

2.2.3. New supply options

New investment decisions can then be made if necessary to compensate for the de-commissioning of existing plants and to meet future demand. Figure 3 reports the long-term investment cost assumptions adjusted using WAPP (2018); Cole and A. Will (2019). The uncertainties surrounding the long-term development of CAPEX of solar photovoltaic technologies, batteries, and supercritical coal, for which Côte d'Ivoire still has little experience, are taken into account by making two sets of cost projections.

2.2.4. Renewable capacity factors

In addition, the annual capacity factors estimated by IRENA (2018) were used to characterize the generations of hydroelectric and wind power. In the case of photovoltaic solar energy, the

Technology	Name of the plant (location)	Inst. Cap. [MW]	Date
CC-GT (NG)	Azito IV - TAG	161	2020
CC-GT (NG)	Azito IV - TAV	81	2021
CC-GT (NG)	Ciprel V - 1er Tranche TAG	255	2020
CC-GT (NG)	Ciprel V - 1er Tranche TAV	135	2021
HYDRO	Gribopopoli	112	2021-2
HYDRO	Singrobo	44	2022
PV	Korhogo Solar (RECA)	20	2019
PV	Poro Power	50	2020
PV	BOUNDIALI (KFW)	30	2020
BIOMASS	BIOKALA	46	2023
COAL	Centrale à charbon (S-Energie)	350	2026
COAL	Centrale à charbon (S-Energie)	350	2029
HYDRO	Louga I	120	2024
HYDRO	Louga II	126	2026

Table 2: Planned power plants until 2030–Source: WAPP (2018)

estimates of the selected capacity factors are based on historical time series from 2006 to 2016 obtained from the Photovoltaic Geographic Information System (PVGIS) (Huld et al., 2012). TIMES-CI-ELC considers the PV solar power plants of ten large cities located in the northern part of Côte d’Ivoire for which the average hourly factors are derived from the ten-year range shown in Figure 4. Further, to account for periods of low solar radiation, i.e. critical days, we consider three historical days with low solar capacity factors displayed in Figure 5 are considered.

By differentiating the capacity factors of solar PV panels, the model captures the effect of low solar production days. For each hour of a representative average day, the least-cost solution is calculated by assuming that each GW of solar will produce electricity according to the average diurnal capacity factor of Figure 4. On critical days, however, generation may differ significantly from the average profile. This is taken into account by balancing the system with capacity factors of Figure 5 on three days of the year when PV generation is particularly low. These three critical days represent only 0.82% of the year. Therefore, the cost minimization solution will reflect the average PV capacity factor for 99.18% of the time, but install sufficient backup capacity to meet the demand on days of low solar production.

2.3. Final electricity demands

TIMES evaluates the least expensive energy system that satisfies the demands of electrical services over time. These demands are the main drivers of the level of investments over the 2016–2050 projection period. TIMES-CI-ELC’s electricity demands are the product of a useful service (in number of subscribers per rate band) and a specific consumption level (in kWh per subscriber). The useful service to be satisfied is expressed in number of customers per tariff class.

The right panel of Table 3 shows the distribution of final demand by voltage level and tariff categories. This choice makes it possible to specify differentiated changes in consumption

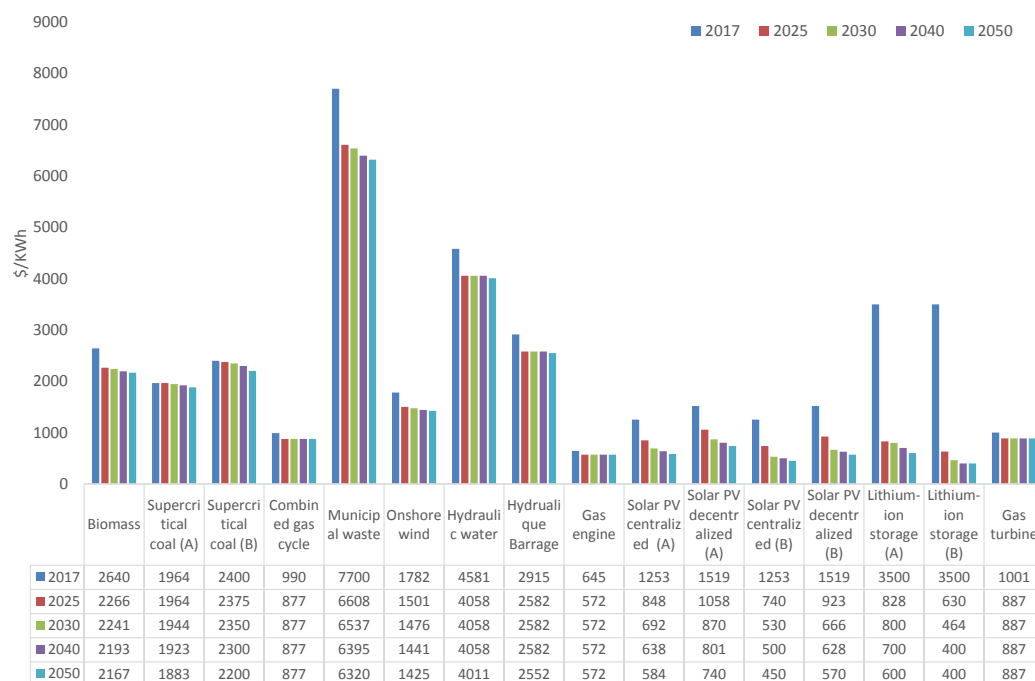


Fig. 3. Investment cost assumption–Compilation of several in constant \$ per GJ for the period 2016–2050–Source: WAPP (2018)

by type of subscriber. We consider three categories of consumers on the low-voltage (LV) network and four categories for the medium- and high-voltage level (MV-HV).

The causal chain starts from the evolution of the number of subscribers for each tranche using GDP as an explanatory variable (see Figure 6). Specific consumption by type of subscribers, as well as their proportions for each voltage level, have been calibrated from historical series available in ANARE-CI (2017); ANARE (2020).

LV			HV-MV		
Tariffs	Subscribers	Cons. (GWh)	Tariffs	Subscribers	Cons.(GWh)
Social dom.	714,685	323	Short util.	61	17
General dom.	999,134	1790	General util.	4788	2,007
General prof.	161,897	855	Long util.	208	947
Others	16,995	506	HV	2	53
			Free	56	25

Table 3: (left) Consumption of LV subscribers; and (right) Consumption of MV-HV subscribers–Source: ANARE-CI (2017)

Using GDP projections from African Development Bank (2011), Figure 7 shows the projected demand for LVs and MT-HTs. Between 2016 and 2050, the level of final electricity demand is about six times higher. To put things into perspective, the projected per capita consumption increases from 0.36 MWh in 2020 to 1.09 MWh in 2050. The projected *per capita* consumption

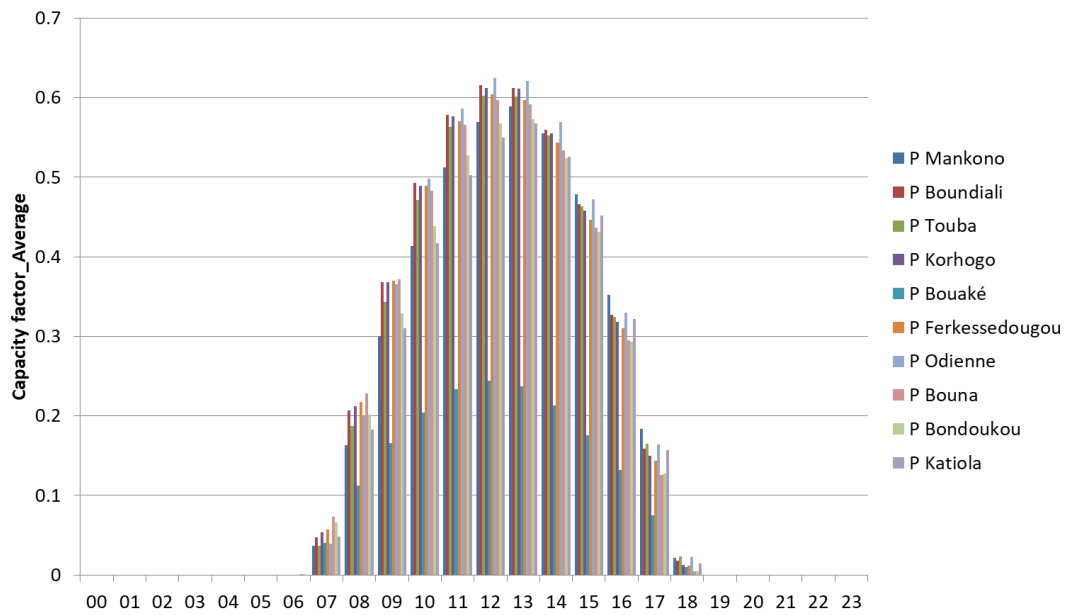


Fig. 4. Average capacity factors of solar PV in various locations in Côte d'Ivoire—Source: Huld et al. (2012)

level in 2050 is about the same as the world average in 1970 or China's average in 2000. At the time of writing this paper, the short- and long-term consequences of the COVID-19 crisis are unknown. Therefore, we deliberately ignore its impacts on the socio-economic variables considered in this prospective analysis. However, our results may be affected by this crisis.

2.4. Modelling direct jobs creation

To connect the results of the model to other socio-economic indicators beyond costs, we chose to calculate the employment content of each scenario in order to compare their potential for job creation and thus social cohesion.

In this section, we describe our assumptions to quantify the impact of alternative energy systems in terms of job creation in TIMES-CI-ELC. We use explicit direct job creation factors from the literature to describe the employment effects over the different life cycle phases for each group of power plants. Five types of jobs are differentiated in the model: (i) manufacturing jobs in importing countries, (ii) fuel processing jobs in importing countries, (iii) construction jobs in Côte d'Ivoire, (iv) operation and maintenance jobs in Côte d'Ivoire, and (v) fuel processing jobs in Côte d'Ivoire. The first two categories refer to jobs outside Côte d'Ivoire.

The methodology used for our analysis builds on the work of Rutovitz and Atherton (2009) and its update Rutovitz et al. (2015). This analysis has recently been extended by Ram et al. (2020) to provide a comprehensive and consolidated source of direct employment factors. However, we do not use the proposed generic regional multiplier factor, calculated on the basis of labor productivity, as a substitute. Although this approach is a good approximation to consistently reflect higher labor factors for some regions, the resulting multiplier for sub-Saharan Africa as a whole ranges from seven to four, which could lead to an overestimate of the number of

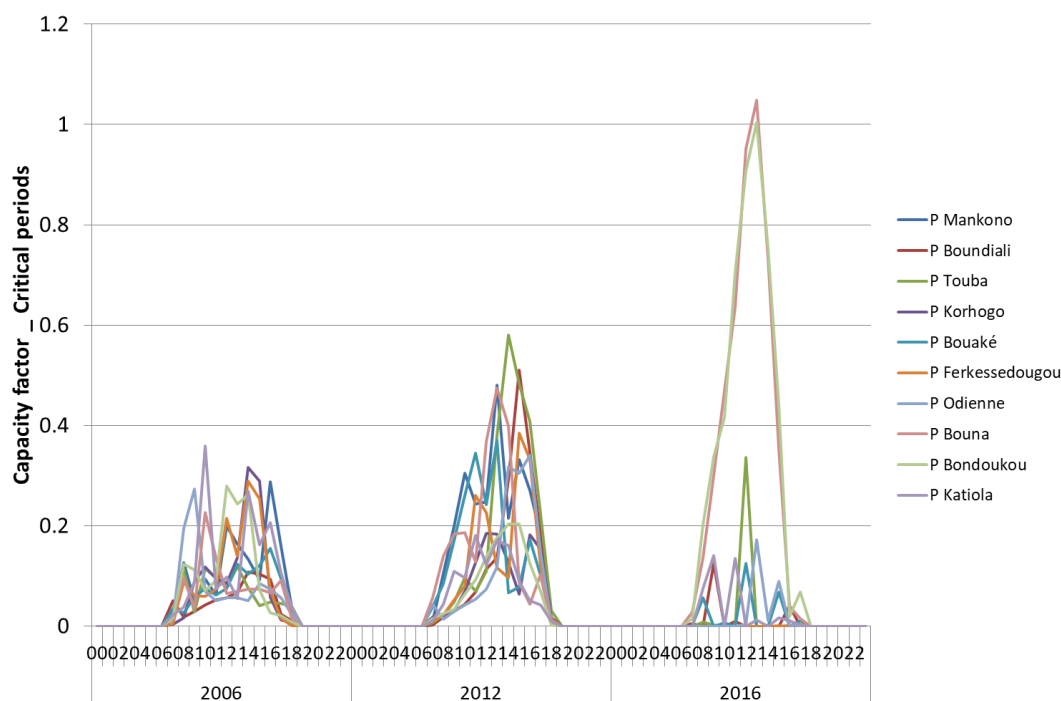


Fig. 5. Capacity factors of solar PV for critical days
–Source: Huld et al. (2012)

jobs for Côte d'Ivoire in 2030 and 2050. We therefore adjust the employment factors using data from specific projects when available.

For thermal power plants, the adjustment is based on a report describing the capacity extension of the AZITO thermal power plant in Côte d'Ivoire (Belrhadoria and Kweku, 2018). 400 people were needed on average during 27 months for a capacity increase from 250 to 335 MW. Compared to the baseline database, this gives a lower regional multiplier of 2.3 assuming a capacity increase of 302MW. The case of the AZITO plant expansion also highlights the difficulty of combining employment factors from multiple sources when the scope is not fully described because the project was expected to mobilize up to 1000 workers at peak activity but only 400 on average.

Employment factors for hydropower plants were adjusted based on the 200 MW Bui Dam in Ghana Tang and Shen (2020), the 44 MW Singrobo-Ahouaty plant in Côte d'Ivoire AFDB (2017), and the 14 MW Bugoye plant in Uganda Scott et al. (2017). Job creation is estimated at 13 direct jobs/MW for the Bui plant and 11.36 jobs/MW for the Singrobo plant. Assuming that these values refer to average employment over the construction period and that a 4-year construction period results in an employment factor of 48 person-years/MW. The data for the Bugoye plant are comparatively more detailed, with a breakdown between work done by contractors and peak and off-peak employment. Taking into account only jobs directly related to the construction of the plant, the employment factor is 42.5 person-years/MW. We retain an adjusted factor of 45 person-years/MW.

It should also be noted that the sources covered a wider range of socio-economic impacts such as water available for irrigation, fishing opportunities or loss of income insufficiently

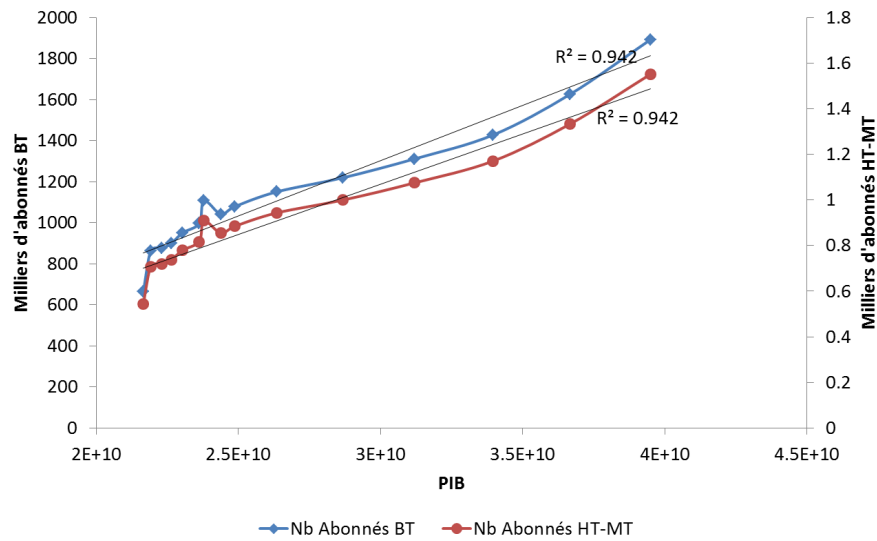


Fig. 6. Evolution of the GDP relative to the evolution of the number of LV subscribers (in blue) and the number of MV-HV subscribers (in red)–Sources: ANARE-CI (2017); ANARE (2020)

compensated for local populations.

For utility-scale solar power plants, we base our adjustment on Lecoufle (2018) that briefly reviews three recent 20–30 MW plants in Senegal. The reported value of 350 jobs for a 30 MW plant is slightly lower than the reference value of 13 job-years per MW proposed by Rutovitz et al. (2015). Although there is not much detail on the methodology used to calculate the employment factors in Lecoufle (2018), this result suggests that the regional multiplier is close to 1 and may indicate that for very competitive bids, the project is optimized and that the construction of a utility-scale solar power plant will not generate 2–3 times more jobs in Côte d’Ivoire. For plant operations, a range of 25 to 50 jobs for 75 MW is mentioned. However, it is unclear whether these are full- or part-time jobs. In the sequel, we use a value of 25 jobs (corresponding to a multiplier of 1.49).

Finally, for wind and ocean energy technologies, we assume a default regional multiplier factor of 3, which is higher than all factors adjusted to imperfectly reflect their lower level of maturity in Côte d’Ivoire.

Table 4 summarizes the assumptions used on both job contents.

3. Scenarios and results

3.1. Scenarios

Today, natural gas is the cornerstone of Côte d’Ivoire’s electrical system. As of 2019, it supplied 67% of the electricity produced, and new capacity is planned in the coming years to meet growing demand. Natural gas has the advantage of a well-structured and familiar decision-making process and value chain. It is a distributable source of electricity, and gas-fired plants are also located close to the largest demand centres in the South of Côte d’Ivoire. However,

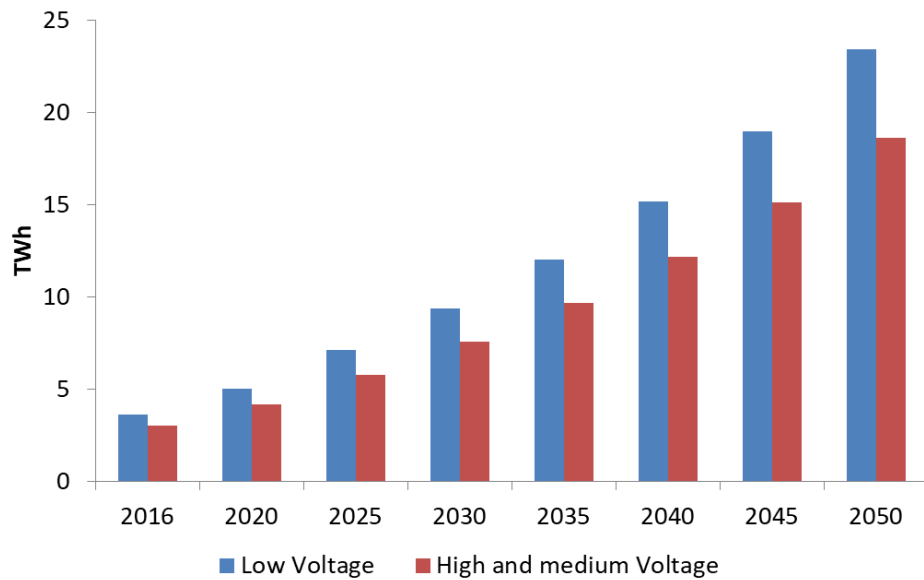


Fig. 7. Evolution of the demand for LV and MV-HV in TWh

	Manuf. j./MW/y	Const. j./MW/y	Operation j./MW/y	Decommiss. j./MW/y	Fuel j./PJ
Gas	0.93	2.98	0.32	0.48	15.1
Coal	5.4	25.63	0.32	3.78	39.7
Fuel oil	0.93	2.98	0.48	1	15.1
Biomass	2.9	34.04	3.43	0.73	387.2
Hydraulics	8.75	45	1.23	13.66	
Cent. Solar	6.7	13	1.04	0.8	
Dec. Solar	6.7	26	2.08	1.21	
Wind turbine	4.7	7.32	0.3	1.65	
Marine	15.6	24	0.6	8.97	
Batteries	16.9	10.8	0.4	0.8	

Table 4: Assumption on the number of jobs

in the coming decades, the depletion of national resources, the saturation of potential hydropower sites, the falling cost of renewable energy and the ratification of international agreements to reduce the world's carbon intensity call for a renewed strategy. For these reasons, this paper pays particular attention to the development of the coal-based process and solar technology. As we have already mentioned, their importance for the development of the electric power mix in Côte d'Ivoire by 2050 motivates our choice.

For the scenario analysis, we consider two sets of competing assumptions, namely: *Favourable to Greener Electricity Mix* (FGEM) and *Unfavourable to Greener Electricity Mix* (UGEM). These two sets have a very large common core of assumptions. They differ on the possible trajectories of future coal prices and solar technologies. The differences are as follows: first, UGEM imposes the deployment of 700MW of coal technology (see Section 2.2.3), whereas FGEM does not have this constraint. Second, the capital costs for coal start in 2017 at US\$2,400/kW for FGEM, which is based on the total costs observed for the supercritical coal-fired power plant of

San-Pédro in Côte d'Ivoire by 2017.⁵ The UGEM takes into account a lower value of US\$1964. The investment cost of centralized and decentralized solar photovoltaics is set at US\$530 in 2030 for the UGEM. In other words, we assume that the average investment costs of solar in 2030 are similar to the average investment costs of large-scale solar projects in West Africa in 2019. On the other hand, UGEM is built on a more pessimistic projection where in 2030, only 40% of the projects reach the 2019 Scaling Solar Level. Finally, the investment cost of lithium-ion storage is also differentiated. The FGEM is based on the lower part of the projections of Cole and A. Will (2019), which is consistent with the projections of WAPP (2018), while the UGEM is based on the average projection of Cole and A. Will (2019).

Scenarios	Solar		Coal		Climate
	Inv costs	Lithium	700MW	Inv costs	100g CO ₂
FGEM	low	low	no	high	no
UGEM	high	high	yes	low	no
UGEM _{100g}	high	high	yes	low	in 2050

Table 5: Summary of the three scenarios

Table 5 presents three scenarios. Two scenarios are derived from the two categories of assumptions: FGEM and UGEM. A third scenario is tested: UGEM with a constraint of 100g of CO₂ per MWh produced in 2050, after UGEM_{100g}. In 2008, according to IAE (2010), the average CO₂ emissions per MWh of electricity produced in Côte d'Ivoire was 449g, while the world average was close to 500g. To be compatible with the long-term objective of the Paris Agreement – to limit the temperature increase to “well below 2C” by 2100 and to continue efforts towards +1.5C–, Allen et al. (2018) calculated that the penetration of renewable energies in electricity production should be between 70–85% in 2050. In addition, Olhoff and Christensen (2019) recommended that this penetration should be 85%. Applying these ratios to the world average as an anchor for a common global target, being as close as possible to +1.5C if it would correspond to having a limit of 100g of CO₂ emissions per MWh in 2050.

All three scenario investigate future expansion plans where the future demand can be met without imports. At the end of this paper, we present 18 additional scenarios that expand the range of possible future conditions covered by the three basic sets of assumptions mentioned above. For each set, we make two new assumptions for three classes of parameters that can influence the optimal technology choice: industry readiness, alternative primary supply conditions, and alternative demands. Although these scenarios do not cover all possible combinations, we argue that exploring them provides a comprehensive overview of the sensitivity of our results. Section 4 will discuss the assumptions of the sensitivity analysis in more detail.

3.2. Evolution of the power mix between 2030–2050

Figure 8 shows the power mix by technology for the three scenarios that satisfy final electricity demands up to 2050, and other technological constraints. The optimal cost combination of the UGEM set of assumptions shows that coal is gradually overtaking natural gas as the preferred supply option, from 23.6% of the mix in 2030 to 44% in 2050. Natural gas remains at

⁵This coal-fired power plant is expected to be the first ever built in Côte d'Ivoire.

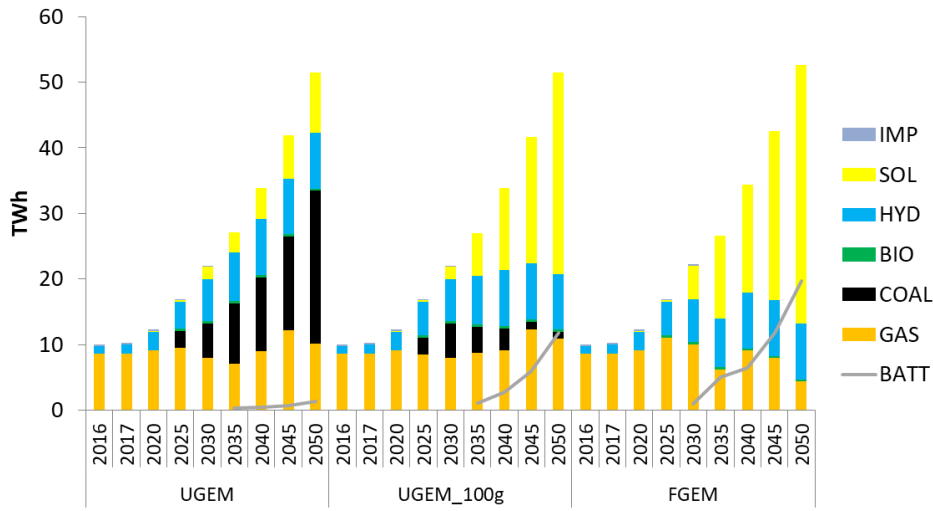


Fig. 8. Power mix by technology to meet demand between 2030 and 2050

levels comparable to those of today, but the increase in demand reduces its share to 19.7%. This scenario also includes an expansion of renewable energy sources, which account for 34.4% of total production in 2050, in other words solar energy represents 1.8 TWh in 2030, 4.7 in 2040, and 9.2 in 2050. The UGEM_{100g} indicates the offset that is necessary to be on a trajectory compatible with the Paris Agreement. In this scenario, coal only becomes a transition fuel. The system reaches 37.4% renewable energy in 2030 and up to 76.2% in 2050. The main source of electricity becomes solar with 30.7 TWh while fossils represents 23.1% (mainly gas). To balance the electricity demand, 11.8 TWh of demand is supplied by a battery storage system.

3.3. Load balancing

Figure 9 shows the evolution of the energy mix that minimizes costs at every hour of the day. For example, on the left side of the graph, the first 24 divisions represent the different hours of an average day from midnight for the UGEM scenario in 2030. In 2030, the UGEM and UGEM_{100g} scenarios show the same trajectories, in particular the gas technology that modulates the variability related to the availability of solar radiation. This pattern is exacerbated in the UGEM scenario, which also highlights the use of batteries during the night. This last scenario shows how solar-based systems start affecting the residual load curve and operation of dispatchable plants. In 2050, even in the UGEM scenario, the higher solar penetration results in virtually no gas during the day. Renewable energies account for 60 to 72% of production between 10 am and 2 pm. UGEM_{100g} and FGEM are almost carbon free and load balancing requires the daily use of batteries as a key element of the system. In the most favourable case, they become the main source of flexibility of the system between day and night.

Figure 10 shows the evolution of the energy mix that minimizes costs at every hour of the day for a critical day. Figure 10 is constructed in the same way as Figure 9. Critical days have been introduced to ensure that the planned system has the capacity to withstand days of low solar production. As shown in Figure 10, the calculated optimal planning must then use the existing thermal power plants to their full capacity.

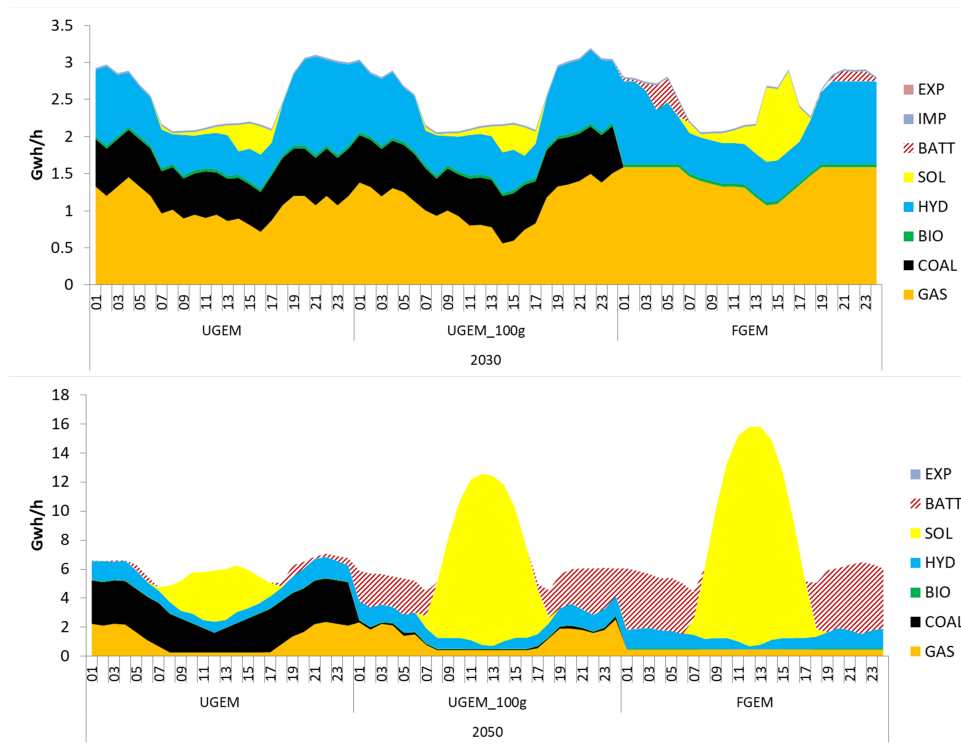


Fig. 9. Load curves for an average day of the three scenarios in 2030 and 2050

3.4. Installed capacity between 2030–2050

Figure 11 shows the installed capacities by technology for the three scenarios that satisfy final electricity demands between 2030 and 2050. The UGEM scenario shows a partial replacement of gas-fired power plants by coal-fired (3.3 GW of coal in 2050) and solar power plants. However, solar has the largest share in terms of installed capacity with 5.6 GW in 2050. This higher share is due to the technology's lower capacity factor. The UGEM_{100g}, to be in line with the Paris Agreement, scenario does not generate any coal capacity in addition to the 0.7 GW prescribed in the model at the beginning of the simulation. If gas production remains relatively low if the climate constraint is added, this scenario offers a different perspective in terms of installed capacity, i.e. 4.2 GW in 2050. More remarkably, solar capacity shows a rapid increase from 1.1 GW in 2030 to 7.7 GW in 2040, and 18.9 GW in 2050. In addition, the storage capacity of batteries also increases sharply to 8.1 GW in 2050.

Finally, assuming a rapid decline in the cost of solar and batteries, the FGEM scenario does not foresee the emergence of coal in the energy mix, even when costs are minimized. This scenario has the highest total installed capacity, 44.7 GW. The installed solar capacity increases from 3.1 to 24.3 GW between 2030 and 2050. In addition, the storage capacity of the batteries reaches a total capacity of 13.5 GW in 2050.

Moreover, among the scenarios, the degree of dependence on international commodity markets, and its price volatility, is not similar. While UGEM shows a very limited dependence on OPEX imports, limited to gas, UGEM's installed capacity suggests a strong exposure to international commodity markets.

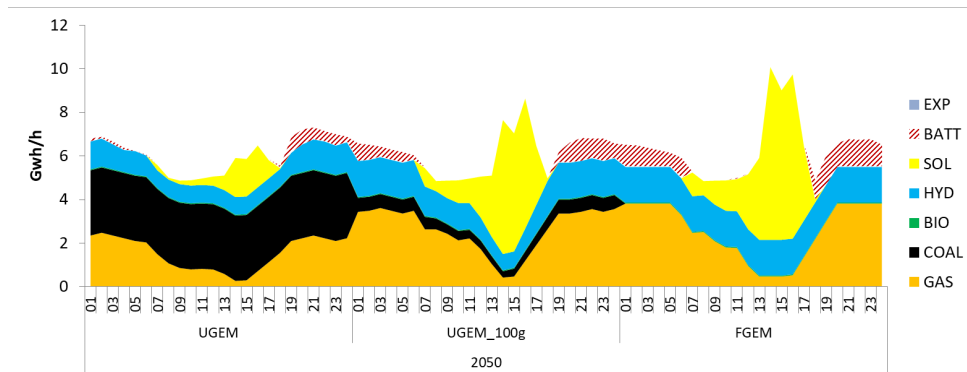


Fig. 10. Load curves for a critical day for the three scenarios in 2050

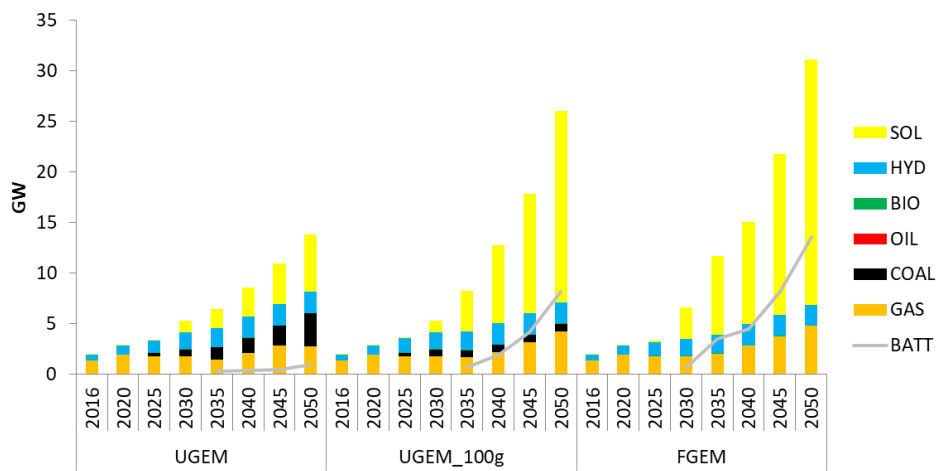


Fig. 11. Capacities installed by technology to meet demand between 2030 and 2050

3.5. CO₂ emissions

Figure 12 presents the CO₂ emissions of the scenarios from 2020 to 2050. While the UGEM scenario is less challenging in terms of installation capacity, its subsequent emissions are not compatible with the Paris Agreement and continue to increase at least until 2050, showing a fivefold increase over the period. The UGEM_{100g} scenario shows a peak in emissions in 2030 at 8.4 Mt before decreasing to 5.1 Mt at the end of the simulation horizon. In the FGEM scenario, emissions peak in 2025 at 5 Mt before decreasing steadily to reach in 2050 38.6% below their current level.

Most of the national commitments are proposed today for 2030. Figure 12 also argues in favor of the need to plan beyond 2030, since UGEM and UGEM_{100g} are close in order of magnitude before 2030 but diverge in the second half of the simulation horizon.

3.6. Average Index of Cost of Production

By construction, the technology path that minimizes total discounted cost also provides a consistent stream of CAPEX and OPEX that are required to meet the set of constraints for a

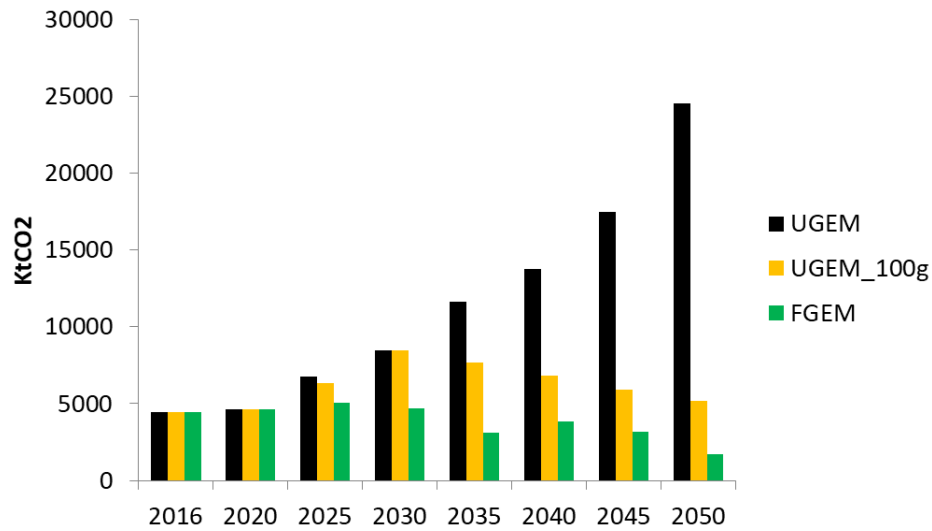


Fig. 12. CO₂ emissions of the three scenarios between 2016–2050

given scenario. Figure 13 shows the evolution of the average costs of electricity production, which is calculated as the ratio between the total annual cost associated with the supply of fuel and the investment and operation of power plants and the quantity of electricity produced corrected for storage efficiency losses.

The average cost of the UGEM_{100g} in 2050 is \$83/MWh, which is 8.6% more than the cost of the UGEM. Moreover, the lowest average cost of electricity is obtained for the FGEM case with \$69.4/MWh in 2050.

The evolution of these costs is explained in more detail in Figure 14, which shows the components of the annual cost of electricity generation. A new scenario is added to the Figure, namely UGEM_{60gas}. This scenario aims to mimic an energy mix in 2050 similar to that of today, where gas represents roughly two-third of the total supply. As previously states, natural gas has the advantage of a well-structured and familiar decision-making process and value chain in Côte d'Ivoire. As suggested by Figure 14, if we compare the UGEM to the UGEM_{60gas}, gas would take the place of solar and partly of coal, which would further reduce the total capacity to install. Consequently, load balancing would be easier, requiring less modulation and batteries. However, CO₂ emissions would be comparable and the cost of production would be higher than that of the UGEM. Indeed, in the UGEM_{60gas} scenario, fuel costs represent the main part of the annual cost and the major part of the cost increase corresponds to the replacement of domestic gas reserves by gas imported from WAGP and then LNG. UGEM then reduces the cost by replacing expensive LNG with coal. The move towards a cleaner mix implies the substitution of OPEX by CAPEX. In UGEM_{100g}, the lower fuel cost is compensated by higher investment levels. The lowest cost in FGEM is then the effect of a greater decrease in fuel costs with a moderate increase in the cost of power plants and batteries.

3.7. Carbon Price

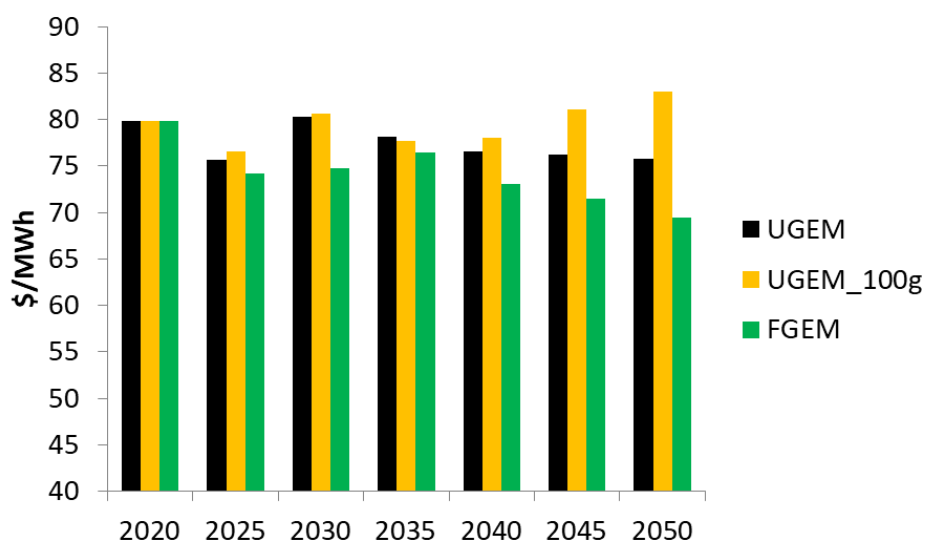


Fig. 13. Average production costs of the three scenarios and a gas scenario between 2016–2050

The implicit carbon value of the UGEM_{100g} scenario is estimated by running the model with a CO₂ target. Due to the linear formulation of TIMES, the value of this constraint can be interpreted as the marginal value of CO₂. In other words, this price is a proxy of the implicit cost of CO₂ to move from UGEM to UGEM_{100g}.

\$/tCO ₂	2030	2035	2040	2045	2050
UGEM _{100g}	0.0	20.8	42.2	61.4	82.5

Table 6: Implicit carbon price of scenario UGEM_{100g} in constant USD between 2030 and 2050

Table 6 shows the implicit price of carbon that ensures 100g of CO₂ emissions per kWh produced in 2050.⁶ It is interesting to note that this price remains relatively low in the 2020s due to the inertia of the current system. In the 2030s, however, this price is expected to increase at a very fast pace, especially at the beginning of the decade. As shown in figures 11, 12, and 13, this decade is crucial to achieve the objectives of the Paris Agreement because it is a turning point in determining the way forward for the electricity mix. In the aftermath of the 2030s, the increase in the implicit price of carbon is relatively slower, reaching nearly US\$75 in 2050.

It is worth noting that according to the NDC and World Bank (2019), policymakers in Côte d'Ivoire are considering a carbon tax for climate action. Indeed, unlike most taxation systems, the carbon tax has a lower evasion potential by nature because it can cover both formal and informal markets if applied upstream of the value-added chain (here at the primary energy level). This feature is particularly relevant, and with high potentially beneficial, for developing economies, in particular Côte d'Ivoire, that currently have large informal sectors Pigato (2019).

To be successfully implemented, public acceptance of the carbon tax may be the key aspect.

⁶Note that the implicit price of carbon for the other scenarios is not worth studying because they show CO₂ emissions in 2050 below the Paris Agreement target.

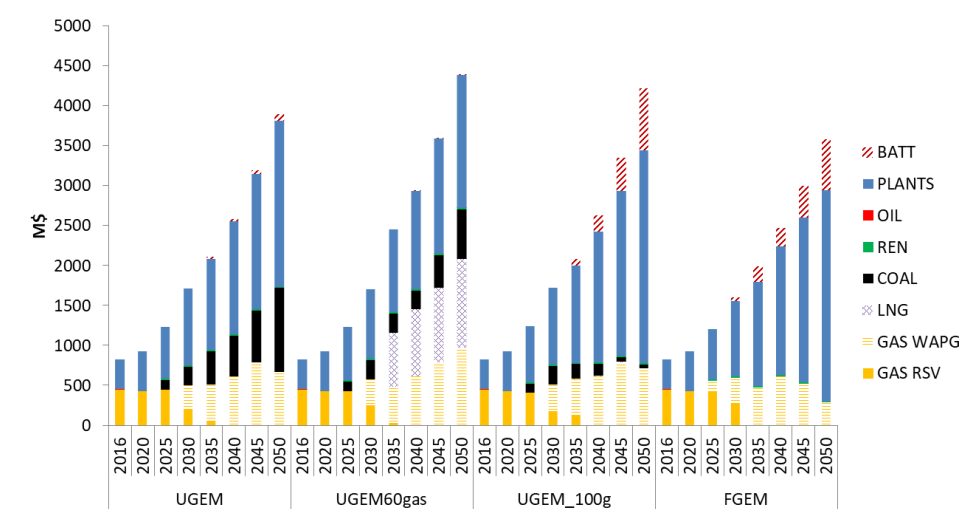


Fig. 14. Components of the annual cost of electricity generation for the three scenarios between 2020 and 2050

World Bank (2019) summarized key practices for successful implementation, among which revenues should be clearly linked to a specific target, as this allows the public to see more clearly what the revenues are financing (Klenert et al., 2018). Specific targets may take the form of further tax reductions, or addressing issues of high public concern. The study of these objectives is beyond the scope of this paper, as it would require a comprehensive macroeconomic framework.

3.8. Employment contents

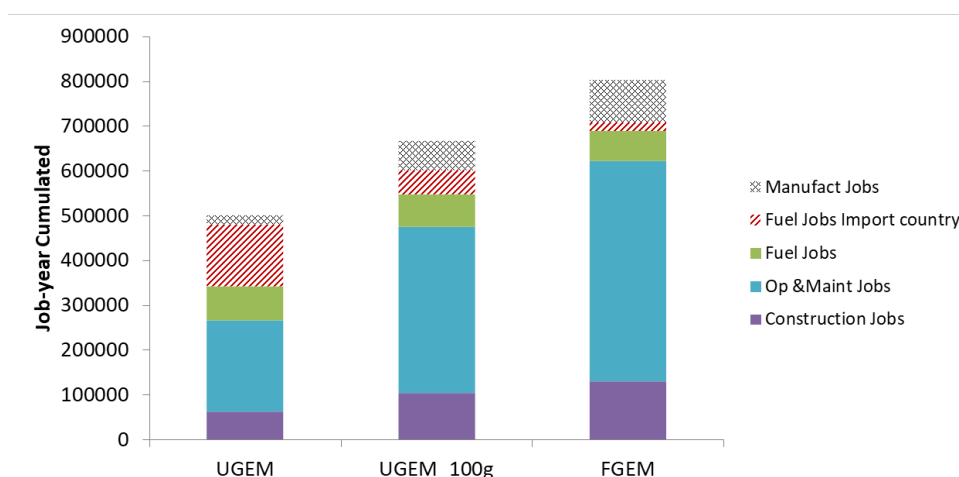


Fig. 15. Comparison of total annual full-time equivalent employment between 2016 and 2050

Figure 15 shows that job levels do not evolve in the same way across scenarios. Indeed, UGEM_{100g} scenario generates 27% more employment than the UGEM scenario while FGEM scenario generates 61% more. Furthermore, UGEM_{100g} and FGEM scenarios generate a 39.4% and 67.5% decline in fuel supply employment respectively. Finally, UGEM_{100g} and

FGEM scenarios generate increases of 82% and 168% for the stages related to the means of production (manufacturing, construction and operation). It should be noted that two categories of jobs (hatched, approximately 100,000) will not be carried out in Côte d'Ivoire: those related to imported fuels, and those related to technology manufacturing.

4. Sensitivity analysis

As mentioned earlier, we now evaluate the sensitivity of our results for three classes of assumptions: industry readiness, alternative primary supply, and alternative demands. For each class, we formulate two hypotheses to describe alternative decision-making contexts. In total, 18 new variants are introduced to test the behavior of the model and explore the effect of uncertainties on its results.

First, we explore the effects of two alternative cases of industry readiness. The "GAS based" case simulates a stated preference for natural gas which has been the mainstay of the supply strategy until now. It is implemented by imposing a minimum share of 60% of installed capacity for natural gas-fired power plants.

Alternatively, we consider a case of a sluggish solar industry where the bottleneck is the maximum expansion rate of the local solar industry. The solar industry in West Africa is still in an early stage of development and average annual installation rates are typically below 150 MW. The case for slow solar development is therefore modeled by considering a maximum of 750 MW of new capacity added for each five-year period. This limit then increases linearly to 5 GW in 2050 (1 GW per year).

Second, we test two primary supply alternatives. The first alternative supply case explores the effect of greater import dependence. It is implemented by allowing up to 1 GW of imported electricity at a cost of \$100/MWh. The second alternative supply scenario then assumes that several significant new gas discoveries are made.⁷ We model such a development by arbitrarily testing the case of a five-fold increase in the remaining natural gas potential.

Finally, we consider two alternative demand scenarios to recognize the inherent uncertainty associated with projecting future electricity demands. This is particularly the case in a developing economy context where the structure of the economy changes rapidly, distributional effects can evolve very quickly, and the electricity intensity of future growth with increasing service sector value added is uncertain. We simply test here a weaker demand case where demand is assumed to lag the projected electricity demand in Figure 7 by 5 years. The alternative case then reflects a higher demand case where future electricity demand grows faster than expected and exceeds its level in Figure 7 by 5 years.

At an aggregate level indicated by Table 7, the observed effects are consistent with the changes in assumptions. An increased contribution from gas with the "gas-based case" and the "optimistic discovery cases" leads to a greater reliance on natural gas. A sluggish solar industry increases emissions, while the lower and higher demand cases respectively reduce

⁷At the time of finalizing this paper, new offshore gas reserves have been discovered in Côte d'Ivoire. This scenario allows us to shed light on the potential implications of this discovery

or increase the contribution of all options except hydro. We highlight a few notable effects here.

The UGEM cases show that imposing a preference for natural gas with a constraint or assuming optimistic discoveries leads to very different substitution mechanisms. When a minimum share of installed natural gas capacity is imposed, higher natural gas generation displaces solar (-98%) much more than coal (-41%). This is because coal-based generation remains cost-competitive, while the additional capacity required for solar is heavily penalized. With more optimistic gas discoveries, absolute solar generation increases by 29%, while coal's contribution decreases by nearly 80%. This indicates that coal assets are at greater risk of failure with optimistic gas discoveries, while solar may benefit from this substitution. As a result, the level of emissions is 39% lower when coal is replaced with more gas. It can also be noted that the UGEM cases show, as expected, that in the absence of specific policies, an increase in demand could lead to a larger market share for solar, but an absolute increase in CO₂ emissions.

The UGEM_{100g} variant analyses show comparatively less variability, as the power system must transition to a lower carbon future. The most notable change here is the effect of a sluggish solar industry environment. In this condition, solar's contribution is limited to 44%, but the constraint can be met by expanding biomass electricity. This result shows that, although bioelectricity is not as cost-effective as solar, it can be a consistent choice to mitigate the impact of a slower effective expansion of the solar industry.

These results are confirmed by the FGEM variants where, despite a more optimistic reduction in capital costs, a slowly expanding solar industry will still require the commissioning of additional coal and gas generation. As a result, emission levels rise sharply. The FGEM cases also show that with an optimistic gas discovery assumption, hydro and solar still contribute 50% of the generation mix. However, this assumption strongly affects the competitiveness of batteries as a balancing solution, with an absolute decrease of 83.4%, and leads to an increase in CO₂ emissions.

Figure 16 provides an overview of the evolution of annualized costs for all scenarios considered in this paper. By 2050, annual system costs could range from a minimum of \$3.2 billion to a maximum of \$6.2 billion. The minimum is observed for low electricity demand, optimistic assumptions related to new natural gas discoveries, and favorable solar and battery capital cost reductions. The maximum corresponds to high demand and an explicit CO₂ constraint. However, the total cost only provides an aggregate indicator of the uncertainties in the financial impact of the future power system.

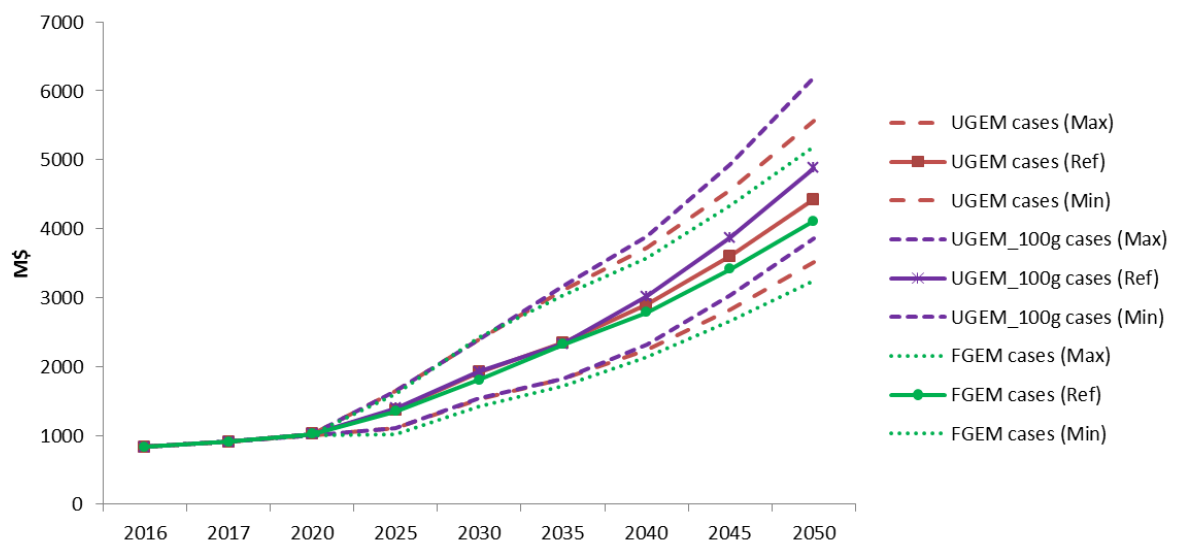


Fig. 16. Maximum, minimum, and reference future cost of each class of scenarios

EXPLORED SCENARIOS		POWER GENERATION TWh (market share)							Emissions MT CO ₂
		BATT	BIO	COAL	GAS	HYD	IMP	SOL	
UGEM	Industry readiness	0.00	0.37 (0.7%)	13.61 (26.5%)	28.74 (55.9%)	8.54 (16.6%)	0.00	0.16 (0.3%)	23.31
	Slow Solar Dev.	1.32	0.33 (0.6%)	23.26 (45.2%)	10.18 (19.8%)	8.54 (16.6%)	0.00	9.19 (17.9%)	24.56
	Alternative primary supply	1.34	0.32 (0.6%)	22.61 (43.9%)	9.99 (19.4%)	8.54 (16.6%)	0.46 (0.9%)	9.57 (18.6%)	23.93
	Optimistic GAS Discovery	0.54	0.34 (0.7%)	4.69 (9.1%)	26 (50.5%)	8.54 (16.6%)	0.00	11.89 (23.1%)	14.26
	Alternative demands	0.88	0.33 (0.8%)	17.96 (42.5%)	8.28 (19.6%)	8.54 (20.2%)	0.00	7.14 (16.9%)	19.15
UGEM_100g	High Demand	2.06	0.33 (0.5%)	26.05 (41.6%)	14.47 (23.1%)	8.54 (13.6%)	0.00	13.27 (21.2%)	28.7
	Industry readiness	-	-	-	-	-	-	-	-
	Slow Solar Dev.	8.27	8.00 (16%)	1.02 (2%)	10.5 (21.0%)	8.54 (17.1%)	0.00	21.88 (43.8%)	5.00
	+IGW import	11.47	0.33 (0.6%)	1.02 (2%)	10.83 (20.8%)	8.54 (16.4%)	0.88 (1.7%)	30.55 (58.5%)	5.12
	Optimistic GAS Discovery	12.36	0.33 (0.6%)	1.02 (2%)	11.08 (21.2%)	8.54 (16.4%)	0.00	31.21 (59.8%)	5.22
FGEM	Alternative demands	8.83	0.33 (0.8%)	1.02 (2.4%)	8.49 (20.2%)	8.54 (20.3%)	0.00	23.74 (56.4%)	4.21
	High Demand	15.71	0.92 (1.5%)	1.02 (1.7%)	13.47 (21.9%)	8.54 (13.9%)	0.00	37.55 (61.1%)	6.15
	Industry readiness	0.01	0.37 (0.7%)	0 (0%)	39.06 (76%)	8.54 (16.6%)	0.00	3.45 (6.7%)	15.20
	Slow Solar Dev.	7.27	0.33 (0.6%)	5.65 (10.9%)	15.46 (29.8%)	8.54 (16.5%)	0.00	21.88 (42.2%)	11.28
	+IGW import	19.49	0.30 (0.6%)	0 (0%)	3.49 (6.6%)	8.54 (16.2%)	0.88 (1.7%)	39.41 (74.9%)	1.37
FGEM	Optimistic GAS Discovery	3.26	0.30 (0.6%)	0 (0%)	25.47 (49.3%)	8.54 (16.5%)	0.00	17.31 (33.5%)	9.95
	Alternative demands	15.50	0.30 (0.7%)	0 (0%)	3.36 (7.8%)	8.54 (19.8%)	0.00	30.94 (71.7%)	1.32
	High Demand	22.44	0.30 (0.5%)	3.97 (6.2%)	5.05 (7.9%)	8.54 (13.4%)	0.00	46.03 (72.1%)	5.57

Table 7: Sensitivity analysis of electricity generation that minimizes costs for the scenarios and policy environment described in the paper under various baseline assumption variations: industry readiness, alternative primary supply, and demand variations– The results show the electricity production in 2050 and its CO₂ emissions counterpart

The observed technology adjustment has implications in terms of trade-offs between capital and operating costs. Figure 17 illustrates these substitutions in more detail for the FGEM versus FGEM variants. While the high demand case shows the largest increase in annualized cost, imposing a minimum share of natural gas generates larger CAPEX and OPEX changes. The preference for gas here creates a situation of imperfect competition where only 40% of the installed capacity can be optimized. This reduces CAPEX requirements for solar and coal but increases OPEX. Similarly, the cost reduction with an optimistic gas discovery assumption is the combined effect of a decrease in CAPEX due to lower investment in solar and batteries and a more limited increase in OPEX due to the availability of cheaper domestic supply. These massive shifts between CAPEX and OPEX indicate possible impacts on Côte d'Ivoire's balance of payments that are, however, beyond the scope of the quantitative insights that a model like TIMES can provide.

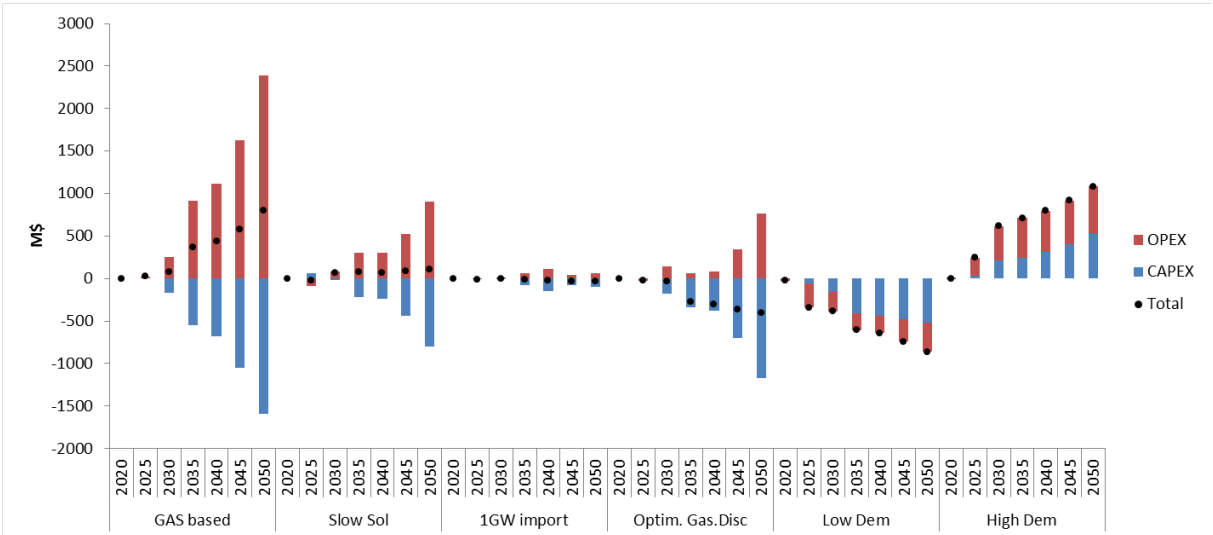


Fig. 17. Changes in CAPEX and OPEX for each scenario compared to FGEM

5. Conclusion and Policy Implications

Over the next four decades, increasing access to electricity in order to improve the living conditions of the population and support the development of industrial activities and productive services will be one of the main energy and economic development challenges for many developing countries. This paper provides a prospective analysis of possible future technology paths for the power sector in Côte d'Ivoire. The challenges of a fast-growing economy are vast and include the future primary supply chain, the choice between competing transformation stages, and the final demand to be met. In line with Côte d'Ivoire's international commitments to aim for a low-carbon trajectory, challenges also involve the corresponding environmental and job creation externalities. Moreover, challenges imply a strong intertemporal dimension that requires a long-term horizon. This paper demonstrates the applicability of a long-term energy system model for the case of Côte d'Ivoire and proposes a model that can highlight several strategic implications of contrasting decision

contexts. We develop and use a TIMES cost minimization model for the energy sector in Côte d'Ivoire to explore these challenges in a systemic manner.

Our estimates show that the demand for electricity could be multiplied by 4.5 by 2050 and reach 42 TWh in 2050. This rapid growth will bring per capita electricity consumption to 824 kWh, which is still less than a third of the world average in 2017. Applying a scenario approach allows us to quantify the optimal transition path for several contrasting futures. While these optimal transitions are not predictions, we argue that they provide useful insights for decision makers by highlighting the implications of alternative choices. Our first three scenarios show that solar photovoltaic energy could provide at least 18% of total electricity generation by 2050. However, this share of solar could also be compatible with a fivefold increase in CO₂ emissions if coal is massively used as a solution to the depletion of national gas resources. Adopting a cleaner energy mix is technically feasible and could increase electricity generation costs by around 10% with our reference cost assumptions for renewable sources. In the same vein, results show that cleaner electricity mix could be achieved through climate policies, such as a carbon price of about US\$21 in 2035 to US\$82 in 2050. However, the assumption of a more ambitious future reduction in the cost of solar panels represents an opportunity to simultaneously satisfy demand, reduce the average cost of electricity, and reduce CO₂ emissions. This strategy will require the rapid commissioning of a considerable amount of photovoltaic and storage capacity between 2030 and 2050. By simulating 18 alternative contexts, we broaden the scope of our assessment to account for potentially more limited development of solar or natural endowment, different assumptions about primary supply, and possible under- or overestimation of long-term demand.

The more sustainable future will indeed require more CAPEX than OPEX. It will also be necessary a need to strengthen the solar PV value chain through capacity building strategies to develop a skilled and sufficient workforce to benefit from a positive employment dividend. Although implementation of such measures is beyond the scope of the model, the cases explored show that the industrial readiness of the solar industry could suffer from a major bottleneck. Massive CAPEX to OPEX transfers could also have significant socio-economic and financial implications. Indeed, the combined effect of reduced imports and increased investment could also have broader macroeconomic impacts that go beyond our current work but could be studied in future research.

Additionally, current limitations in the level of disaggregation of the model offer interesting perspectives for future work. Our results indicate that bioelectricity could be a relevant solution in case of limited solar development. Since the agricultural sector plays a major role in the economy of Côte d'Ivoire, it could be interesting to further explore the competitiveness and co-benefits of a bioelectricity supply chain. The geographical dimension could also be strengthened by regionalizing and distinguishing between urban and rural demands. Finally, extending the model to neighboring countries could help quantifying the benefits of regional integration.

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