Energy and Power Engineering, 2026, 18(11), 777-806
https://www.scirp.org/journal/epe
ISSN Online: 1947-3818
ISSN Print: 1949-243X

Electricity Demand Growth and Security of Supply in Côte d'Ivoire: Statistical Analysis for 2014-2025 and Scenarios to 2030

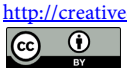
Kone Gbah*, N'Guetta Akpagni Rene, N'Guessan Konan Felix Renato

Laboratoire d'Ingénierie Electronique, d'Electricité et des Systèmes Embarqués (LIEESE), Institut National Polytechnique Félix Houphouët-Boigny (INPHB), Yamoussoukro, Côte d'Ivoire
Email: *gbah.kone@inphb.ci

How to cite this paper: Gbah, K., Rene, N.A. and Renato, N.K.F. (2026) Electricity Demand Growth and Security of Supply in Côte d'Ivoire: Statistical Analysis for 2014-2025 and Scenarios to 2030. *Energy and Power Engineering*, **18**, 777-806.
https://doi.org/10.4236/epe.2026.1811036

Received: September 28, 2026
Accepted: November 2, 2026
Published: November 5, 2026

Copyright © 2026 by author(s) and Scientific Research Publishing Inc.
This work is licensed under the Creative Commons Attribution International License (CC BY 4.0).
http://creativecommons.org/licenses/by/4.0/



Open Access

Abstract

Electricity demand is increasing rapidly in Côte d'Ivoire due to population growth, economic development, urbanization, and expanded access to power. While this growth supports the country's development, it also puts additional pressure on generation capacity, transmission and distribution networks, and regional electricity exchanges. This work examines progress in electricity demand from 2014 to 2025 and provides projections through 2030. The study begins by assessing trends in the main indicators (electricity consumption, domestic generation, imports, export balance, customers number, distribution efficiency and average outage duration) by using three complementary methods: linear regression, the Mann-Kendall test, and Sen's slope. Pearson, Spearman and partial correlations controlling for time are then used to give additional insight into the relationship among these variables. The results show that domestic electricity consumption nearly doubled between 2014 and 2025, increasing from 7333 to 14,635 GWh. This growth trend was statistically established, with a coefficient of determination of $R^2 = 0.956$, a p-value below 0.001 and a Sen slope of 625 GWh/year. Furthermore, imports also increased significantly, while the net export balance decreased by approximately 101 GWh/year. The relationship between electricity consumption and imports remained strong and positive after controlling for the effect of time, with a partial correlation coefficient of $r = 0.782$ and a p-value of 0.0044, confirming that this association is statistically significant. In 2025, these imports reached 708 GWh, while total plant availability dropped to 79 percent, with a net balance of only about 90 GWh. Finally, three main scenarios project consumption between 18.7 and 21.5 TWh by 2030. Consequently, generation capacity, network infrastructure, and plant availability need to improve in line with growing electricity demand to reduce the risk of supply shortages and greater de-

pendence on electricity imports. Although these findings do not represent a probabilistic adequacy assessment, they reveal consistent signs of a tightening supply demand balance and support the need of integration planning generation, transmission and distribution infrastructure, losses reduction, and regional interconnections.

Keywords

Electricity Demand, Security of Supply, Ivorian Power System, Trend Analysis, Energy Scenarios

1. Introduction

Electricity has become a key indicator of a country's economic and social development. It supports industry, services, communications, healthcare, education and better living conditions. Across Africa electricity demand grew by 3.4% in 2024, compared with slightly than 2% in 2023 [1]. Consequently, ensuring a reliable, stable and less expensive power supply in the context of population growth, rapid urbanization, and climate change creates new challenges.

Côte d'Ivoire is distinguished for the dynamism and resilience of its economy. In 2024, its gross domestic product (GDP) was about 6%, compared with an average of 3.2% for sub-Saharan Africa. Between 2011 and 2024, the country recorded average annual economic growth of 6.1%, supported mainly by investment, infrastructure, agriculture, industry, and services. This performance gives it a central role within the West African Economic and Monetary Union (UEMOA). Although it accounts for about 21% of the Union's population, the country generates nearly 40% of its nominal GDP and approximately 42% of its exports [2]. Côte d'Ivoire power system supports an expanding economy and contributes to electricity exchanges within the West African Power Pool (WAPP). The country has historically exported electricity to several regional countries, including Burkina Faso, Mali, Liberia, Sierra Leone, and Guinea. Maintaining this role requires additional generation capacity and modernizing transmission and distribution networks to meet domestic demand and honor export contracts. Interconnections provide valuable flexibility, but they cannot replace reliable generation capacity or a strong power grid [3]-[5].

The 2025 data reveal a mixed picture. Installed capacity reached 3224 MW, while net domestic generation increased to 14,563 GWh. During same year, domestic electricity consumption totaled 14,635 GWh, and the availability of generation facilities fell to 79%. In addition, electricity imports nearly doubled compared with 2024. Gas supply shortages, changes in hydropower availability and aging generation, transmission, and distribution equipment increase the risk of severe system constraints during peak demand period [6]-[8]. However, recent studies in Côte d'Ivoire have focused mainly on long-term energy planning, generation mix, political economy of the power sector and the factors driving demand

[9]-[12]. Other research has examined regional planning and the benefits of cross border electricity trade [4] [5] [13]. In contrast, few studies have examined how recent demand growth relates to actual availability of power facilities, changes in network losses, service quality, and reduction in the net export balance.

Consequently, this research project makes three main contributions: First, it analyses together indicators of demand, supply, network performance, service continuity and electricity trade, which are generally examined separately. Second, it statistically verifies the observed trends using parametric and nonparametric methods suited to a small annual dataset. Third, it distinguishes early signs of system stress from a full probabilistic adequacy assessment, which requires hourly data and detailed outages records. The analysis is guided by three questions: Which trends were statistically significant between 2014 and 2025? Did imports continue to increase after controlling for the effect of time? Finally, how much electricity will be needed by 230 under annual growth rates of 5%, 6.5%, and 8%, with a 10% sensitivity case? The goal is to produce a transparent and reproducible assessment that can serve as a foundation for more detailed studies.

2. Conceptual Framework and Literature Review

2.1. Security of Supply and Resource Adequacy

Resource adequacy refers to a power system's ability to meet demand using available production capacity, energy storage, electricity exchanges and other flexibility [14]. A high-level installed capacity alone does not guarantee adequacy. Forced outages, scheduled maintenance, fuel supply constraints, hydrological conditions, network limitations, and the availability of imports must also be considered. Modern approach therefore recommended using several indicators that measure the frequency, duration and severity of supply shortfalls rather than relying on a single reserve margin [14]-[16].

Probabilistic indicators such as Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP), and Expected Energy Not Served (EENS) remained the standard tools for assessing resource adequacy. However, calculating these indicators requires hourly demand data, unit level outage rates, maintenance schedules, hydrological profiles and electricity exchanges. When such data are unavailable, an annual analysis can identify potential supply risks but cannot provide a full probabilistic adequacy assessment.

2.2. Electricity Demand Growth and Access

Electricity consumption depends on household income, urbanization, industrialization, electricity prices, and access to the power grid. A study covering Côte d'Ivoire, Ghana, Nigeria, and Senegal confirm the importance of income and demographic factors in driving demand [11]. Prosumers should be considered in demand forecast, as their consumption patterns could significantly affect the future electricity needs of newly connected households [17].

In Côte d'Ivoire, the Electricity for All Program (Programme Électricité Pour

Tous: PEPT) has significantly accelerated access to the grid. The total number of customers increased from 1.32 million in 2014 to 5.28 million in 2025, including 2.72 million customers connected through the PEPT program [17]. While this represents major social progress, it also creates new obligation: ensuring a reliable electricity supply for these new customers.

2.3. Power Interconnections and Regional Vulnerability

Electric interconnections allow countries to share reserves, combine different energy resources and reduce costs. In West Africa, they offer considerable potential, particularly by combining the use of hydropower, thermal generation, and solar energy [3] [4] [18]. However, their effectiveness depends on the availability of transmission and distribution infrastructure, consistent electricity trading rules and generation surplus that can be mobilized [4] [19] [20]. An increase in imports may simply reflect efficient system operation. However, they become a warning sign when they occur alongside declining domestic generation availability, rapid growth in electricity demand and a sustained reduction in the net export balance.

3. Data and Methodology

3.1. Data Source and Scope

Table 1. Main variables used to analyze Côte d'Ivoire's power system.

Dimension	Variable	Unit	Period	Purpose
Demand	Gross demand for electricity consumption	GWh	2014-2025	Measure electricity demand
Supply	Net domestic generation	GWh	2014-2025	Tracks change in domestic electricity supply
Cacacity	Thermal, hydropower and solar capacity	MW	2020-2025	Describes the generation mix
Availability	Total plant availability	%	2020-2025	Measure the capacity available for operation
Electricity trade	Imports and exports	GWh	2014-2025	Assesses the country's position in regional electricity trade
Networks	Transmission and distribution efficiency	%	2014-2025	Evaluates network performance
Service continuty	Average outage duration (TMC), SAIDI, SAIFI and energy not supply (ENS)	H, number and MWh	Depending on data availability	Assesses of service quality
Access	Custumers and PEPT beneficiaries	Number	2014-2025	Measure the expansion of electricity access

The complete annual data supplied by the Ivorian Electricity Company (CIE), including the units and definitions of all indicators used in this study is presented in the **Appendix**. it compiles technical, commercial, and financial indicators for the Ivorian electricity sector. The data source covers the period from 2014 to 2025.

The variables include net domestic generation, gross domestic electricity consumption, transmission and distribution efficiency, average outage duration, energy not supplied and the numbers of customers. The dataset also contains installed capacity by generation and total plant availability. Table 1 presents the main variables used to analyze changes in the Ivorian power system, together with their observation period and their role in the study.

3.2. Calculated Indicators

The average growth rate over a given period is measured using the compound annual growth rate (CAGR) as expressed in Equation (1).

$$\text{CAGR} = \left[\left(\frac{X_f}{X_i} \right)^{1/n} - 1 \right] \times 100 \tag{1}$$

where X_i *and* X_f *are the initial and final values, respectively and* n *is the number of annual intervals.*

The net electricity trade balance is calculated using Equation (2)

$$NTB_t = Exports_t - Imports_t \tag{2}$$

where NTB_t *is the net electricity trade balance,* $Exports_t$ *is the amount of electricity exported,* $Imports_t$ *is the amount of electricity imported and* t *represents the year under consideration.*

The annual import dependence rate is calculated relative gross domestic electricity consumption using Equation (3)

$$IDR_t = \left(\frac{Imports_t}{Domestic\ consumption_t} \right) \times 100 \tag{3}$$

where IDR_t *is the import dependence rate,* $Imports_t$ *is the amount of electricity imported,* $Domestic\ consumption_t$ *is the gross domestic electricity consumption and* t *represents the year under consideration.*

Finally, the apparent losses associated with network efficiency are estimated using Equation (4)

$$Losses_t = 100 - R_t \tag{4}$$

where $Losses_t$ *represents the apparent network losses,* R_t *is the transmission or distribution network efficiency and* t *represents the year under consideration.*

These indicators are descriptive. The import dependence rate alone does not measure the risk of an electricity shortage, since imports may result from economic dispatch decisions. It should therefore be interpreted together with domestic generation availability and the net electricity trade balance.

3.3. Statistical Analysis of Trends and Relationships

Linear regression is used to estimate the average annual change in each indicator and how well the trend fits the data. The Mann-Kendall test and Sen's slope are also applied to limit the influence of extreme values and avoid relying solely on

the assumption of normally distributed data [21]-[23]. The significance level is set at 5%.

The linear trend is estimated using Equation (5):

$$X_t = \alpha + \beta t + \varepsilon_t \tag{5}$$

where X_t *is the value of indicator in year* t, α *is the intercept or estimated value of the indicator when* $t = 0$, β *is the regression slope which represents the average annual change in indicator,* ε_t *is the error term which captures the variation not explained by the linear trend.*

Sen's slope is calculated using Equation (6):

$$\beta_{Sen} = median\left(\frac{X_j - X_i}{j - i}\right), \quad j > i \tag{6}$$

where β_{Sen} *is the Sen's slope,* X_j *and* X_i *are the values at time* i *and* j *respectively.*

Because the Mann-Kendall test assumes that successive observations are independent, each series was checked for fist-order correlation. The trend was first removed using Sen's slope, as shown in Equation (7)

$$X_t' = X_t - \beta_{Sen} t \tag{7}$$

where X_t' *is the detrended value in year t.*

Lag-1 correlation was then calculated from the ranks of the detrended observations. Its significance was assessed using the approximate 95% limits given by Equation (8).

$$r_{1,crit} = \pm\frac{1.96}{\sqrt{n}} \tag{8}$$

where $r_{1,crit}$ *represents the critical autocorrelation limits and n is the sample size.*

For the 12 annual observations used in this study, the limits were approximatively ±0.566. An autocorrelation coefficient outside these limits was considered statistically significant.

When significant serial correlation was detected, the Hamed-Rao modified Mann-Kendall test was applied. This method adjusts the variance of the Mann-Kendall statistic using Equation (9):

$$Var^*(S) = Var(S)\left[1 + \frac{2}{n(n-1)(n-2)}\sum_{k=1}^{m}(n-k)(n-k-1)(n-k-2)\rho_k\right] \tag{9}$$

where $Var^*(S)$ *is the corrected variance,* $Var(S)$ *is the original Mann-Kendall variance and* ρ_k *is the significant autocorrelation at lag k and m the maximum lag considered.*

For the original Mann-Kendall test, exact two-sided p-values were used for series without tied observations. For series containing ties, the variance was adjusted for tied values and p-values were calculated using the normal approximation with continuity correction.

Relationship between pairs of variables are measured using Pearson and Spearman correlations coefficients. Because two variables may appear strongly, partial

correlation is also calculated after removing the linear effect of the year. These coefficients describe statistical associations and should not be interpreted as evidence causality.

3.4. Development of the 2026-2030 Scenarios

Three main demand scenarios are developed using 2025 as the base year. The moderate scenario assumes an annual growth rate of 5%, representing a slowdown in electricity demand. The trend scenario uses 6.5%, which is close to the arithmetic mean of the annual growth rates observed over the study period. The accelerated scenario assumes 8%, a rate consistent with the recent growth reported in the annual review. A 10% growth rate is included only as a high-growth sensitivity case.

Electricity consumption for each year is projected using Equation (10)

$$C_t = C_{2025}\left(1+g\right)^{t-2025} \tag{10}$$

where C_t *is the projected electricity consumption in year t,* C_{2025} *is the electricity consumption recorded in the base 2025,* g *is the assumed annual growth rate.*

A linear extrapolation is also provided as a benchmark, together with a 95% prediction interval. The difference between the linear projection and the compound-growth scenarios reflects uncertainty related to the choice of the mathematical model. In other words, the results depend on whether future demand is assumed to increase by a constant amount of energy each year or by a constant annual percentage.

3.5. Validation Checks and Methodological Limitations

Since only 12 annual observations were available, ARIMA modeling was not considered reliable. The lack of hourly load, generation, outages, hydrology, and electricity trade data also prevented a probabilistic adequacy assessment using indicators such as LOLE and EENS [14] [24]-[26].

4. Results and Discussion

4.1. Demand Is Growing Faster than Domestic Generation

Gross domestic electricity consumption nearly doubled between 2014 and 2025, rising from 7333 to 14,635 GWh, with a compound annual growth rate (CAGR) of 6.48%. On the same period, net domestic generation increased from 8166 to 14,563 GWh, corresponding to a CAGR of 5.40%. As shown in **Figure 1**, gross demand grew slightly faster than generation, gradually reducing the margin between domestic supply and consumption.

The number of customers quadrupled from 1.32 million to 5.28 million, with a CAGR of 13.47%. This suggests that many new customers are still consuming relatively little electricity. However, demand could continue to rise as households acquire more electrical appliances and productive uses expand. **Table 2** summa-

rizes these changes, including the strong growth in consumption, customers number, and imports between 2014 and 2025. Gross domestic consumption and net domestic production are based on different accounting scopes. Gross domestic consumption is calculated based on gross production before deducting auxiliary consumption by power plants, whereas net production excludes this internal use.

Table 2. Trends in the main ındicators of Côte d'Ivoire's power system, 2014-2025.

Indicator	2014	2020	2024	2025	Main change
Net domestic generation (GWh)	8166	11,031	13,733	14,563	+72% since 2014
Gross Domestic electricity consumption (GWh)	7333	10,029	13,572	14,635	+99.6% since 2014
Customers (millions)	1.32	2.92	4.59	5.28	4 times since 2014
Electricity exports (GWh)	902	1333	730	797	−11.6% since 2014
Electricity imports (GWh)	20	149	382	708	35.4 times since 2014
Network efficiency (%)	78.59	82.54	84.56	84.54	+7.57 percentage points

4.2. Statistical Significance of the Trends

As shown in Figure 2 and Table 3, electricity consumption increased steadily between 2014 and 2025. The linear trend explains 95% of its annual variation ($R^2 = 0.956$). Significant serial dependence was detected after removing the trend ($r_1 = 0.698$). However, the increase remained statistically significant after the Hamed Rao correction ($p = 0.001$). Sen's Slope indicates that consumption increased by approximately 625 GWh per year.

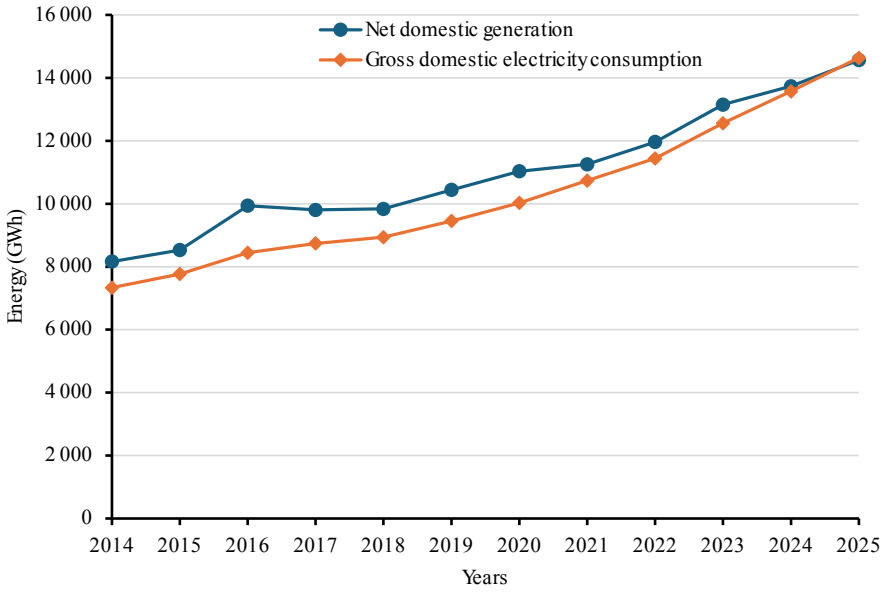


Figure 1. Trends in net domestic generation and domestic electricity consumption, 2014-2025.

Domestic generation also increased significantly by approximately 555 GWh

per year. No significant serial dependance was found in this series ($r_1 = 0.698$) and its adjusted p-value remained below 0.001. Because consumption increased faster than domestic generation, the margin between national supply and demand gradually narrowed.

Table 3. Trend analysis results for the main ındicators of Côte d'Ivoire's power system, 2014-2025.

Variable	OLS slope/Year	R^2	Kendall's τ	Original p_{MK}	Detrended r_1	Hamed-Rao p	Sen's Slope/Year	Sen's 95% CI
Electricity consumption	632.4	0.956	1.000	<0.001	0.638	0.001	625.2	[494.8, 725.0]
Domestic generation	543.1	0.956	0.939	<0.001	0.397	<0.001	555.2	[455.0, 658.4]
Electricity imports	50.2	0774	0.879	<0.001	0.297	<0.001	40.9	[30.0, 59.0]
Net trade balance	−80.8	0.487	−0.515	0.021	0.082	0.024	−101.4	[−157.0, −14.0]
Numbers of costumers	353990.9	0.972	1.000	<0.001	0.324	0.001	351661.2	[303698.2, 384950.4}
Distribution efficiency	0.8	0.872	0.779	<0.001	0.184	<0.001	0.8	[0.6, 1.0]
Average outage duration	−1.3	0.295	−0.321	0.149	0.617	0.322	−1.5	[−3.0, 0.3]

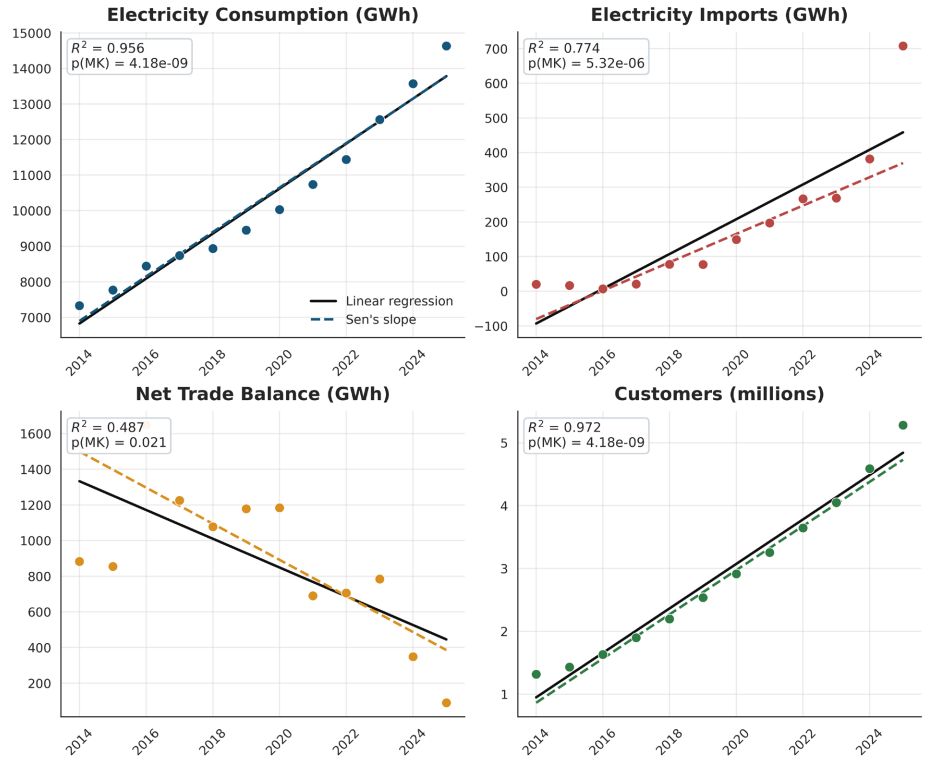


Figure 2. Statistical trends in electricity consumption, imports, net trade balance, and customer numbers, 2014-2025.

The number of customers rose from 1.32 million in 2014 to 5.28 million in 2025 and remained on a significant upward trend after correction ($p = 0.001$).

Electricity imports, increasing by approximately 41 GWh per year ($p < 0.001$), while the net trade balance declined by approximately 101 GWh annually ($p = 0.024$). Côte d'Ivoire remained a net exporter of electricity, but the gap between exports and imports gradually narrowed.

Distribution efficiency improved by about 0.8 percentage point per year over the full period ($p < 0.001$), despite a slight decline after 2022. Average outage duration also decreased, but this trend was not statistically significant after correction ($p = 0.322$).

4.3. Relationships among Demand, Imports, and the Net Trade Balance

As shown in **Figure 3**, electricity consumption, domestic generation, imports and customers numbers generally increased together between 2014 and 2025. The particularly strong correlation between consumption and costumer growth reflects the effect of expanded electricity access on domestic demand. Domestic generation also increased with consumption, but at a slightly slower rate, which gradually reduced the margin between supply and demand.

Electricity consumption showed a strong correlation with imports (Pearson, $r = 0.939$, $p < 0.001$); Spearman ($\rho = 0.965$). This relationship remained positive and statistically significant after controlling for the common time trend (partial $r = 0.782$, $p = 0.0044$). Thus, years with unusually high consumption were generally associated with higher electricity imports. This finding highlights the growing role of regional trade in meeting domestic demand. However, imports also depend on the availability of production capacity, hydrological conditions, gas supplies, and regional electricity prices.

The net trade balance showed a negative correlation with both consumption and imports. After controlling for the time effect, the relationship between consumption and the net balance remained negative but was not statistically significant (partial $r = -0.545$, $p = 0.083$). In contrast, the relationship between imports and the net balance remained significant (partial $r = -0.678$, $p = 0.022$). However, this result should be interpreted with caution, because the net trade balance is defined as exports minus imports. The negative association with imports is therefore partly mechanical and does not establish a causal link.

Distribution losses, expressed as a percentage, generally decreased as consumption, generation, imports, and customer numbers increased, reflecting improvement in network performance over much of the period. However, the slight decline in distribution efficiency observed after 2022 suggests that this improvement has not continued consistently in recent years. The average duration of outages showed only a weak to moderate correlation with the other indicators, confirming that service interruptions also depend on equipment failures, maintenance, network configuration, and the effectiveness of restoration efforts.

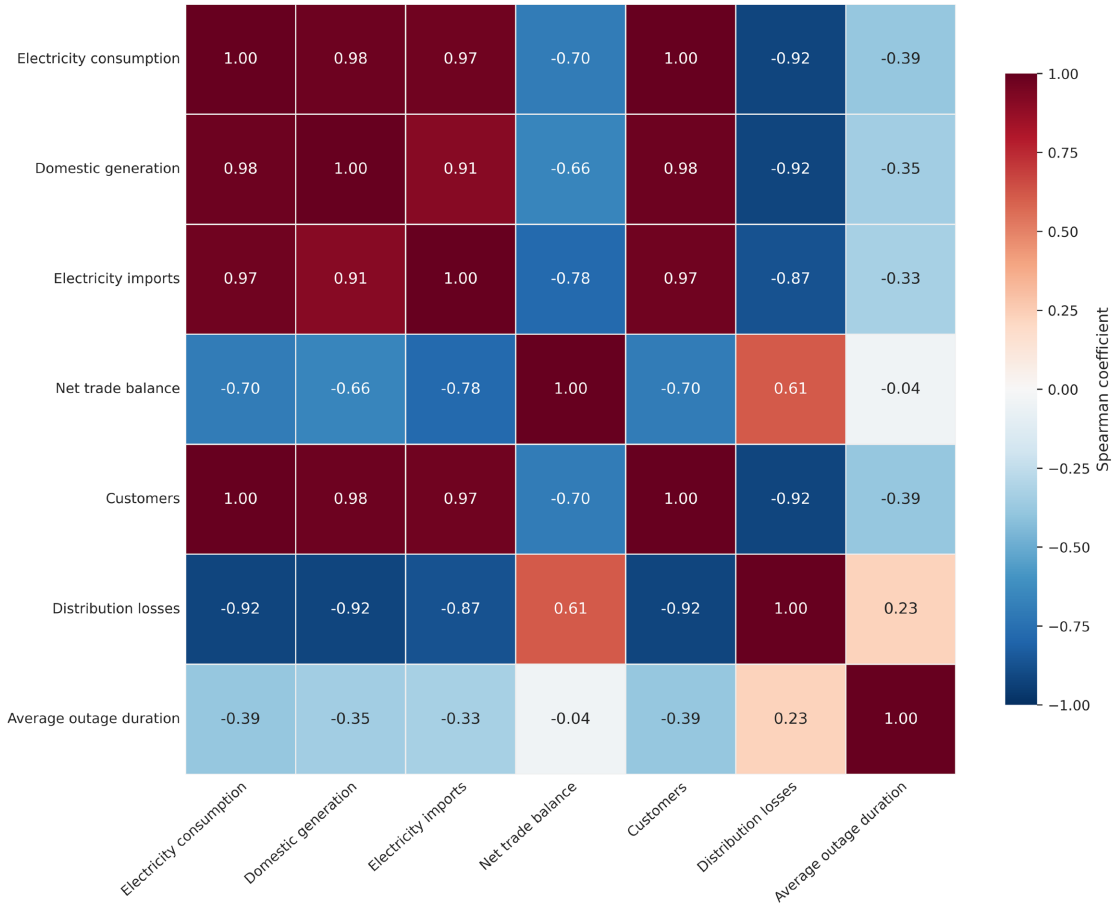


Figure 3. Spearman correlation matrix for the main indicators of Côte d'Ivoire's power system, 2014-2025.

4.4. Rising Installed Capacity but Declining Availability

As shown in **Figure 4** and **Table 4**, Côte d'Ivoire's installed generation capacity increased from 2229 MW in 2020 to 3224 MW in 2025, a gain of 995 MW, or 44.6%. This expansion was driven mainly by thermal power generation, which rose from 1350 to 2166 MW following the commissioning of new units, the expansion of the Atinkou power plant, and additional Aggreko capacity. Hydropower increased more modestly from 879 to 991 MW, while solar entered the generation mix in 2023 and reached 67 MW in 2025, supports by the Boundiali solar power plant.

In 2025, thermal plants accounted for 67.2% of installed capacity, compared with 30.7% for hydropower and 2.1% for solar power. Although thermal generation offers adjustable capacity, this structure makes the power grid vulnerable to constraints on natural gas supply, fuel costs, and power plant outages.

Despite the expansion of the generation fleet, the total availability of power plants fell from 98% in 2021 to 79% in 2025. A simplified estimate based on multiplying installed capacity by the annual availability rate gives an indicative value available capacity decreased approximately from 2645 MW in 2023 to 2547 MW in 2025, even as nominal capacity increased by 317 MW. This simplified calcula-

tion does not constitute an estimate of available capacity during peak periods, as annual availability does not take into account the timing or simultaneous occurrence of power plant outages. It simply illustrates how lower availability can reduce the expected benefits of new generation capacity.

Aging hydropower facilities, prolonged outages, maintenance needs, gas supply constraints, and the unavailability of thermal power plants may explain this deterioration. These findings show that creating new capacity alone is not enough to guarantee supply security. Refurbishing existing assets, shorter outage periods, effective maintenance, and reliable fuel supply are equally important. System adequacy should therefore be assessed using the capacity that can be delivered during peak demand rather than on installed capacity alone.

Table 4. Installed capacity by generation technology and total plant availability, 2020-2025.

Year	Thermal (MW)	Hydropower (MW)	Solar (MW)	Total (MW)	Plant availability (%)
2020	1350	879	0	2229	86
2021	1390	879	0	2269	98
2022	1669	879	0	2548	95
2023	1998	879	30	2907	91
2024	1998	991	30	3019	81
2025	2166	991	67	3224	79

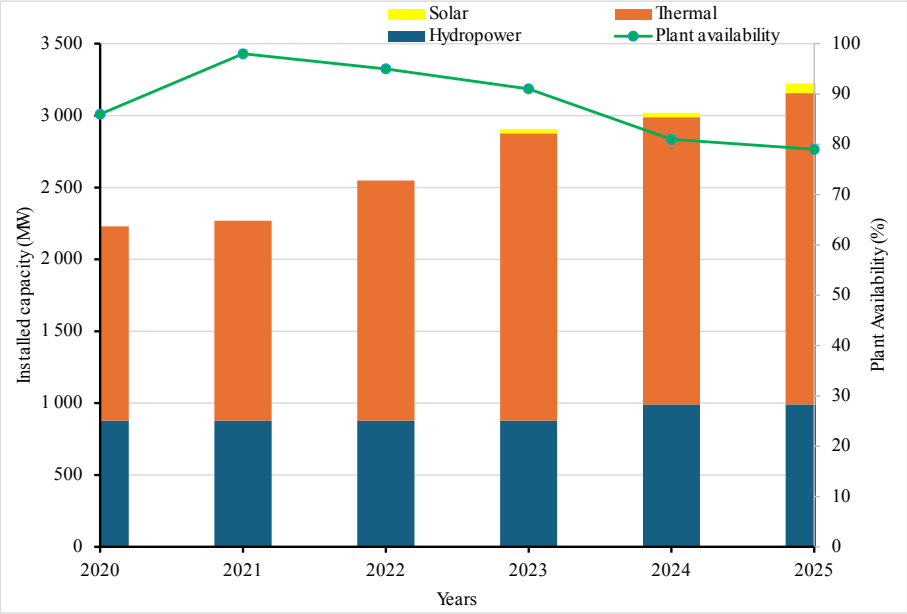


Figure 4. Installed generation capacity by technology and total plant availability, 2020-2025.

4.5. Declining Net Exports

As shown in **Figure 5**, Côte d'Ivoire's cross-border electricity trade changed sig-

nificantly between 2014 and 2025. Exports peaked at 1655 GWh in 2016 and remained relatively high through 2020, when they reached 1333 GWh. They then declined to 730 GWh in 2024 before recovering slightly to 797 GWh in 2025.

Imports followed the opposite pattern. After remaining below 100 GWh per year through 2019, they rose from 149 GWh in 2020 to 267 GWh in 2022, 382 GWh in 2024, and finally to 708 GWh in 2025, an increase of nearly 4.8 times over five years. Although these purchases represented only 4.84% of domestic electricity consumption in 2025, their rapid growth is an important signal of supply security.

Consequently, the net trade balance fell from 1184 GWh in 2020 to 706 GWh in 2022, 348 GWh in 2024 and only 90 GWh in 2025. Côte d'Ivoire therefore remained a net exporter, but with a very narrow margin. Imports accounted for nearly 89% of exports in 2025, compared with just 11% in 2020.

Regional interconnections offer valuable flexibility by supplying electricity during power plant outages, peak demand periods, or when lower-cost energy is available from neighboring countries. However, the simultaneous increase in imports, the decline in the export surplus, reduction in domestic plant availability and sustained demand growth suggest that the grid's internal margins are tightening. If this trend continues, Côte d'Ivoire could temporarily become a net importer during years of high consumption or in the event of major production constraints.

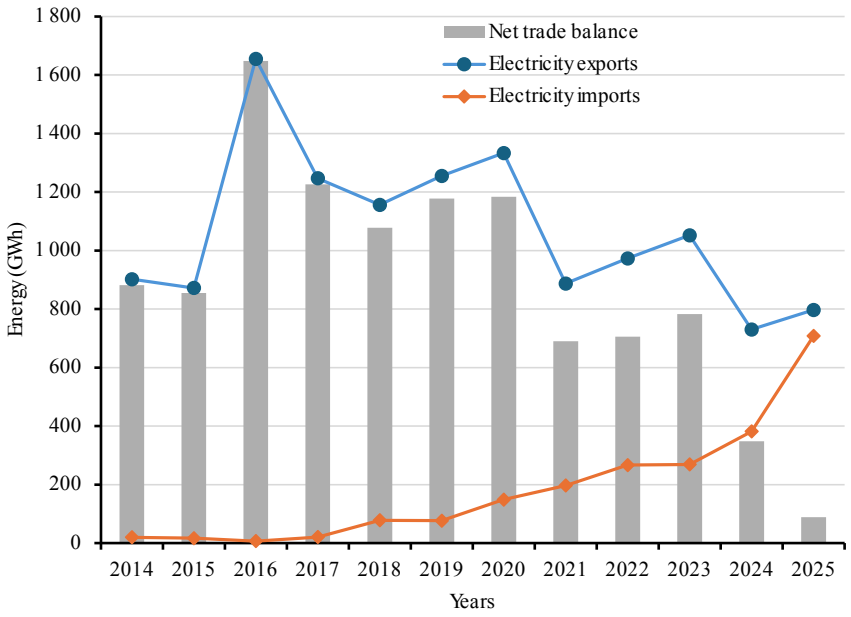


Figure 5. Trends in electricity exports, imports, and the net trade balance, 2014-2025.

As shown in **Figure 6**, plant availability and electricity imports generally moved in opposite directions between 2020 and 2025. The Pearson correlation was moderately strong and negative ($r = -0.695$), indicating that lower availability tended to coincide with greater reliance on external supply. For example, imports totaled approximately 195 GWh when availability reached 98% in 2021 but increased to

382 GWh in 2024 and 708 GWh in 2025 as availability fell to 81% and 79%, respectively. However, this relationship was not statistically significant at the 5% level ($p = 0.125$), largely because the analysis covered only six annual observations. The result should therefore be viewed as a preliminary signal rather than solid evidence of a systematic relationship. The data also reveal some variability: availability was relatively low in 2020, at 86%, but imports nevertheless remained limited to 149 GWh. In addition, the sharp rise recorded in 2025 likely had a strong influence on the estimated correlation.

From an operational perspective, electricity purchases can compensate for unavailability of domestic generation when local resources are insufficient to fully meet demand. Nevertheless, their level also depends on consumption growth, regional electricity prices, the generation capacity of neighboring countries, interconnection constraints, and grid operation strategies. An increase in imports cannot therefore be attributed solely to declining plant availability.

A more reliable assessment would require monthly, daily, or hourly data. Such information would help determine whether imports increase during generating unit outages or peak demand periods while accounting for domestic production, market prices, and contractual exchanges.

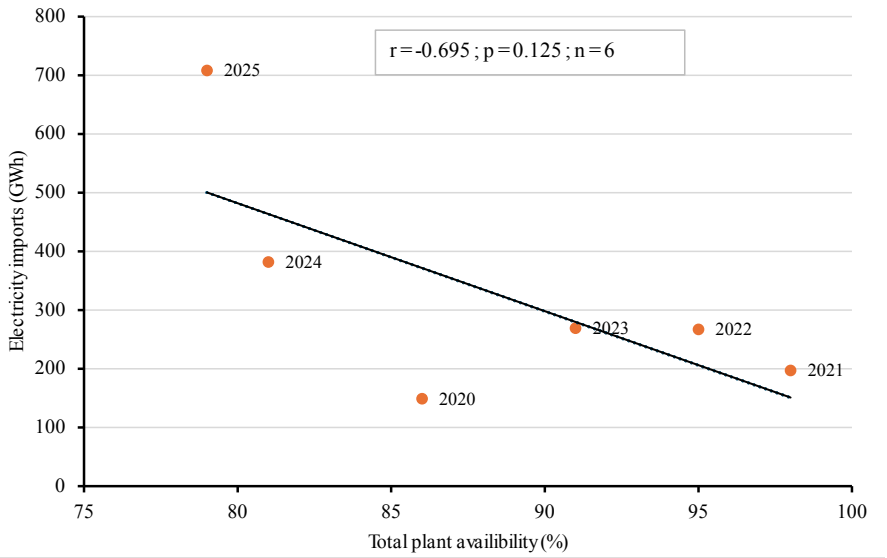


Figure 6. Relationship between total plant availability and electricity imports, 2020-2025.

4.6. Recent Reliability but Persistent Network Losses

As shown in **Figure 7**, transmission losses remained relatively low and stable, generally ranging between 5% and 8%. In 2025, they fell to 5%, corresponding to a transmission efficiency of 95%, the highest level recorded since 2019.

Distribution performance improved significantly between 2014 and 2022, with efficiency rising from 82.4% to 91.3% and losses decreasing from 17.6% to 8.7%. However, this progress subsequently slowed: efficiency fell to 89.38% in 2025, while losses increased to 10.62%. This recent deterioration could be attributed to

rapid network expansion, customer growth, overloaded feeders, the length of distribution lines, load imbalance, aging equipment and non-technical losses. The available data does not allow the contribution of each factor to be measured separately.

Table 5 shows that the network's overall efficiency remained nearly unchanged at 84.54% in 2025, meaning that approximately 15.5% of available energy did not reach end users. Improved transmission performance largely offset lower distribution efficiency, showing that loss-reduction efforts should focus on this part of the network.

Service reliability improved in 2025 compared with 2024, but the available data do not establish a statistically significant long-term trend ($p = 0.322$). The average duration of outages fell from 26.2 hours in 2024 to 18.6 hours, a reduction of approximately 29%. During the same period, the SAIDI fell from 17.6 to 10 hours, while the SAIFI decreased from 22 to 18 interruptions. Energy not supplied also dropped 22.5%, from 37,723 to 29,227 MWh. Nevertheless, these values remain above their 2020 levels; therefore, several additional years of data are needed to confirm lasting improvement.

Approximately 59% of the energy not supplied in 2025 was associated with the medium-voltage network. Reinforcing heavily loaded feeders, automating switching operations, improving fault location, strengthening preventive maintenance, and clearing vegetation near power lines could therefore reduce outages duration and accelerate service restoration.

Finally, year-to-year comparisons should be interpreted with caution. The average duration of outages, the SAIDI and SAIFI indices, and energy not supplied values are fully comparable only when calculated for the same service area and according to consistent rules for counting customers and interruptions [27]. The 2025 results indicate significant short-term progress, but a longer and methodically consistent dataset is required to establish a sustained trend.

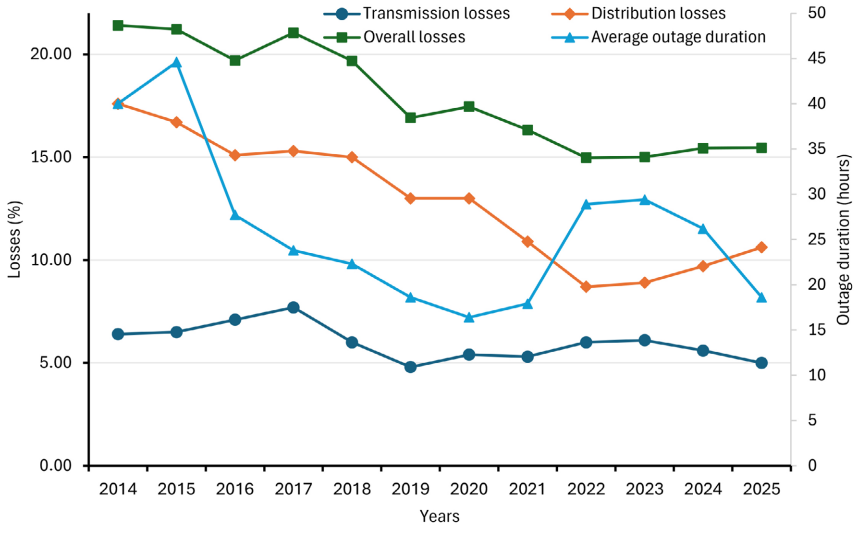


Figure 7. Trends in network losses and average outage duration, 2014-2025.

Table 5. Network efficiency and service reliability ındicators, 2020-2025.

Indicator	2020	2022	2023	2024	2025
Transmission efficiency (%)	94.6	94	93.9	94.4	95.0
Distribution efficiency (%)	87.0	91.3	91.1	90.3	89.38
Overall system efficiency (%)	82.54	85.02	84.99	84.56	84.54
Average outation duration (hours)	16.4	28.9	29.4	26.2	18.6
Total energy not supplied (MWh)	17,231	34,820	38,828	37,723	29,227
SAIDI (hours)	10.8	19.06	19.5	17.6	10
SAIFI (number of interruptions)	20	23	22	22	18

4.7. Electricity Demand Scenarios to 2030

Figure 8 and Table 6 present historical domestic electricity consumption through 2025 and three possible growth scenarios for 2026-2030. Demand increases under every scenario, while the gap between projections becomes larger over time.

In the moderate scenario, consumption grows by 5% per year and reaches 18,678 GWh in 2030, 4043 GWh or 27.6% above the 2025 level. The trend scenario extends the historical average growth rate of 6.5%, resulting in 20,051 GW, a 37% increase. This trajectory may serve as a reference to planning if customer connections, household electricity use, industrial activity and electrification continue to develop at rates like those observed recently.

The accelerated scenario assumes 8% annual growth and brings demand to 21,504 GWh by 2030, nearly 47% higher than in 2025. Such a trajectory could result from faster industrialization, the expansion of mining, wider electrification, or higher consumption among newly connected households. A 10% sensitivity case produces 23,570 GWh, representing an increase of more than 61%. Although this is not considered a central projection, it provides a useful stress case for assessing system resilience under stronger growth.

The difference between the moderate and accelerated scenarios increases from 439 GWh in 2026 to 2826 GWh in 2030. Including the high-growth sensitivity case increases the gap to 4892 GWh at the end of the projection period. This uncertainty underscores the need for flexible decision-making regarding generation, network expansion, and energy procurement.

A linear extrapolation gives a lower 2030 estimate of 16,944 GWh, with a 95% prediction interval of 15,379 to 18,510 GWh. This value is 3107 GWh below the 6.5% trend scenario. This difference reflects the modeling approach: the linear model adds an approximately constant amount each year, whereas compound growth applies a fixed percentage to an increasingly larger consumption base.

These results should be interpreted as planning scenarios rather than precise forecasts. Economic conditions, energy efficiency, electricity prices, industrial projects, air conditioning use, electric mobility, and production activities could affect future demand. Moreover, the values represent annual energy requirements, not the additional generation capacity needed. System planning must also account

for network losses, plant auxiliary consumption, outages, regional exchanges, peak demand, load profile, and reserve margins.

Table 6. Projected electricity consumption by scenario, 2026-2030 (GWh).

Year	Moderate scenario (5%)	Trend scenario (6.5%)	Accelerate scenario (8%)	Sensitivity scenario (10%)
2026	15,367	15,586	15,806	16,099
2027	16,135	16,599	17,070	17,708
2028	16,942	17,678	18,436	19,479
2029	17,789	18,827	19,911	21,427
2030	18,678	20,051	21,504	23,570

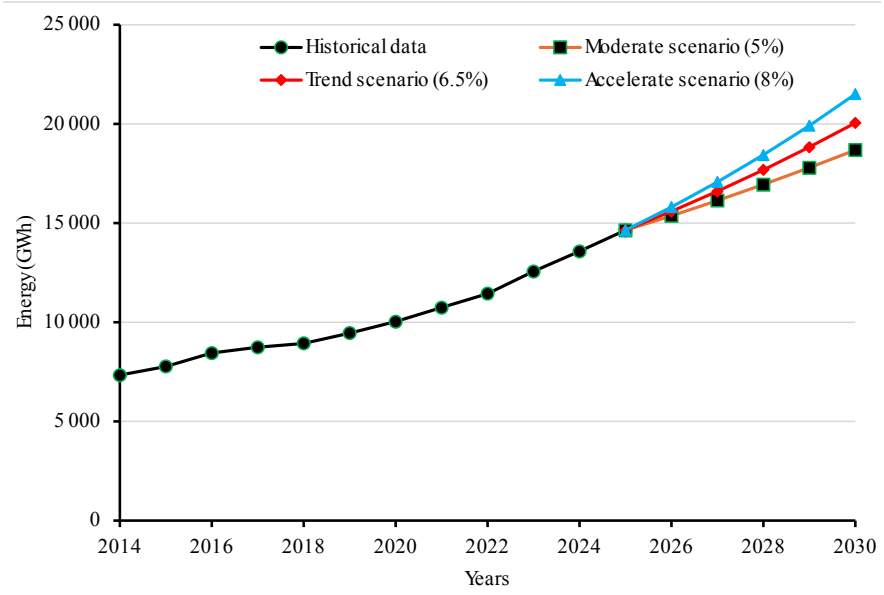


Figure 8. Historical electricity consumption and demand scenarios to 2030.

5. Discussion

5.1. The Main Risk Is the Gap between Installed and Available Capacity

The first major finding is that an increase in installed capacity does not necessarily an equivalent improvement in security of supply. Between 2020 and 2025, Côte d'Ivoire added nearly 1000 MW of generation capacity, while the total plant availability decline by seven percentage points. A generation unit that is out of service, constrained by fuel shortages or affect by network limitations contributes little or nothing to meeting demand. Modern methods for assessing resource adequacy therefore consider outages, weather conditions, energy constraints, and the actual availability of interconnections, rather than relying solely on nominal capacity [14] [15].

Côte d'Ivoire should combine investments in new energy sources with better use of its existing infrastructure. Rehabilitating aging hydropower facilities, re-

ducing thermal plants outages, securing natural gas supplies, and improving maintenance coordination could deliver benefits more quickly than building another large power plant.

5.2. Diversification Is Progressing but Remains Limited

Solar generation doubled in 2025 but still accounted for only 1% of net national generation and about 2% of installed capacity. Thermal plants remained dominant, supplying 73% of the country's electricity. Although these facilities offer dispatchable output, their importance increases vulnerability to natural gas supply constraints and fuel price volatility. Hydropower offers a flexible domestic resource, but its contribution depends on hydrological conditions and plant availability.

Long-term studies suggest that Côte d'Ivoire can expand its solar photovoltaic generation while continuing to pursue its economic and climate goals [7]. Better coordination and electricity exchanges within the West African Power Pool could also support the integration of variable renewable energy [5]-[8]. However, further diversification will require flexible reserves, economically justified storage, better weather forecasting, modernized distribution systems, and stronger transmission infrastructure. In practice, the contribution of solar capacity supply security depends not only on its nominal rating but also on its location and production profile.

5.3. Distribution Loss Reduction as a Hidden Resource

Reducing distribution losses provides an indirect but immediately available source of energy. Every percentage point avoided represents electricity that no longer needs to be generated, imported, or transmitted. With annual consumption above 14 TWh, a one-point improvement could save more than 140 GWh, depending on the parameters of the calculation. The decline in distribution efficiency observed since 2022 therefore requires a detailed assessment to distinguish between technical losses and non-technical causes, such as unauthorized connections, metering errors, and billing issues.

Technical measures may include upgrading overloaded conductors, improving phase balance, locating transformers closer to load centers, and installing reactive power compensation devices. Commercial actions should focus on detecting irregular connections, improving metering accuracy and deploying smart meters in priority areas.

These measures should be guided by detailed loss mapping at substations, transformers and medium- or low-voltage feeder level. This approach would focus investments on areas with the greatest energy and financial benefits and make it easier to track long-term results. In many cases, reducing losses can generate equivalent energy savings more quickly and at a lower cost than building new generation capacity.

5.4. Interconnections Should Remain a Source of Flexibility

The sharp increase in imports in 2025 could be explained by the normal use of

regional interconnections to address temporary supply constraints. It demonstrates the practical value of the West African Power Pool (WAPP) in supplementing domestic generation, reducing the risk of shortages, and providing access to lower-cost electricity. Regional power exchanges can therefore help balance the system without requiring immediate investment in new capacity.

However, total import capacity cannot be considered permanently available. Its contribution depends on surplus generation in neighboring countries, interconnections availability, and transmission constraints along regional corridors. Dry conditions, peak demand, or major equipment failures can affect several countries simultaneously, reducing their ability to support one another.

System planning must therefore consider at least two operating conditions: a normal interconnection scenario, in which imports are available within contractual and technical limits and a stress scenario in which regional exchanges are partially or completely unavailable. Intermediate cases could include the loss of a major interconnection or simultaneous generation shortages in several countries.

This approach would provide a more realistic estimate of how regional trade contributes to security of supply and would help determine the export volumes that Côte d'Ivoire can maintain without compromising domestic demand. Interconnections should complement sufficient and reliable domestic production rather than permanently replace it.

5.5. Implications of the Demand Scenarios

According to the trend scenario, domestic electricity consumption reaches 20.1 TWh by 2030, approximately 37% above 2025 level. To meet this demand, simply adding a few generation units will not be enough. Planning must coordinate investments in generation, transmission lines, substations, distribution networks, system control, and flexibility resources. Without an integrated approach, new plants could be constraints by network limitations or fail to support peak demand effectively.

The accelerated scenario reaches 21.5 TWh, while 10% growth sensitivity case approaches 23.6 TWh. Although the latter is not considered the most likely outcome, it provides a useful stress test for the power system. Even the moderate scenario rises to 18.7 TWh, requiring more than 4 TWh of additional energy within five years. Each trajectory therefore requires significant and timely investments, given the long construction periods for power plants, power transmission lines and substations.

The lower linear extrapolation also shows that these projections are uncertain. Future consumption will depend on the select modeling approach and changes in economic activity, industrial development, electricity rates and final consumption patterns. These results should therefore be treated as a range of possible scenarios rather than a single forecast.

The projections are consistent with studies anticipating strong electricity demand growth in Côte d'Ivoire [9] [28]. However, this analysis does not determine

an optimal generation mix or minimize total system costs, as TIMES, PyPSA, and regional optimization models generally do. Its purpose is to extend recent trends, quantify the possible scale of future needs and provide a practical basis for testing the robustness of investment decisions.

6. Planning Implications

As summarized in Table 7, supply security requires more than new generation capacity. Immediate priorities should include rehabilitating aging units, improving maintenance coordination, securing fuel supplies and reducing transmission and distribution losses. System performance should be evaluated by considering the actual plant availability, forced outage rates, fuel constraints, and N-1 network loading, rather than nominal capacity alone.

New generation units must also be coordinated with the modernization of transmission networks and substations to prevent congestion. At the distribution level, mapping technical and non-technical losses by substation and feeder would support targeted investments and increase both delivered energy and revenue.

In the medium term, Côte d'Ivoire should develop a diversified portfolio combining adjustable generation, hydropower, solar power, storage and demand response where economically justified. Regional interconnections should remain a source of flexibility, but their availability must be tested under adverse conditions, while export commitments should ensure sufficient margins for domestic demand and reserves.

Finally, access to hourly load profiles, unit-level outage records and network incident data would support more reliable assessments using probabilistic indicators such as LOLE and EENS.

Table 7. Recommended planning priorities, monitoring ındicators, and expected outcomes.

Priority	Proposed action	Monitoring indicator	Expected outcome
Plant availibility	Rehabilitate aging generation units and coordinate maintenance schedules	Plant-level availability and forced-outage rate	Rapid recovery of firm capacity
Fuel supply	Secure natural gas supplies and develop shortage scenarios	Days of fuel inventory and capacity constrained by gas shortages	Reduced fuel supply risk
Transmission network	Reinforce corridors and substations approaching their operating limits	N − 1 loading and transformer load rate	Reduced network congestion
Distribution	Identify and reduce technical and nontechnical losses	Efficiency by substation and feeder	More energy delivered and higher revenue
Flexibility	Improve forecasting, demand response, and targeted energy storage	Reserve requirements, ramp rates, and avoided peak demand	Greater solar integration
Regional trade	Test firm import availability under stress conditions	Firm exchange capacity and simultaneous regional events	More realistic assessment of regional supply security
Data	Publish anonymized hourly load profiles and unit-level outage data	Data completeness and reporting frequency	Reproducible LOLE and EENS calculations

7. Limitations and Future Research

This study has four main limitations. First, annual data do not capture hourly

peaks, ramping requirements, or temporary network congestion. Second, total plant availability cannot replace unit-level outage rates. Third, annual electricity trade volumes provide no information on import capacity during critical periods. Finally, the scenarios assume constant growth rates without explicitly modeling macroeconomic factors.

Future research should focus on developing an hourly dataset covering at least three to five years, including demand, unit level generation, reserves, outages, hydrological conditions, gas supply, and interconnection flows. Chronological Monte Carlo simulation could then be used to estimate LOLE, LOLH, and EENS values [26]. Capacity expansion models could also compare investment portfolios based on costs, emissions, resilience to drought, and fuel dependency, using tools such as MAED, TIMES, EnergyPLAN, or PyPSA [28]-[30]. Future analysis should also include N-1 network constraints and the location of new generation plants.

8. Conclusions

Côte d'Ivoire's power system expanded significantly between 2014 and 2025. Domestic generation, installed capacity, network infrastructure and the number of customers all increased, thereby promoting broader access to electricity, economic activity, and regional trade. However, available supply has not kept pace with rapidly rising demand.

Domestic electricity consumption nearly doubled, from 7333 to 14,635 GWh, while generation grew more slowly. Despite the addition of almost 1000 MW since 2020, total plan availability fell to 79% in 2025. This confirms that installed capacity alone is not an adequate indicator of supply security.

Regional trade shows a similar tightening. Imports reached a record of 708 GWh in 2025, reducing the net export balance to only 90 GWh. Interconnections have helped offset domestic constraints, but their availability cannot be guaranteed when neighboring countries face simultaneous shortages or peak demand. Network performance was also mixed: transmission efficiency reached 95%, while distribution losses remained high at 10.62%. Recent improvements in outage duration and frequency, as well as in energy not supplied, are encouraging but need to be confirmed over a longer period.

By 2030, the three main scenarios project annual consumption between 18.7 and 21.5 TWh, with the high-growth sensitivity case reaching 23.6 TWh. Even the moderate trajectory requires more than 4 TWh of additional energy within five years. To meet this need, coordinated investments will be required in available generation capacity, fuel supply security, grid reinforcement, renewable energy, flexible reserves, demand response, storage where economically justified, and the reduction of distribution losses.

However, this study has certain limitations, as it is based on annual data that do not capture hourly peaks, short outages, or seasonal constraints. Future work should use hourly demand, generation, outages, and electricity exchanges data to facilitate integrated planning and probabilistic assessments using indicators such

as LOLE and EENS.

In general, Côte d'Ivoire has strong assets, including a diversified generation fleet, regional export experience and a growing domestic market. Preserving these advantages will depend on converting installed capacity into reliable output, improving network efficiency, and anticipating future demand through coordinated, transparent, and regularly updated planning.

Author Contributions

Kone Gbah: Conceptualization; methodology; validation; formal analysis; investigation; resources; data curation; writing; original draft; preparation; writing review and editing; vizualisation; supervision; N'Guetta Akpagni Rene: Investigation; resources; vizualisation; N'Guessan Konan Felix Renato: Investigation; resources; vizualisation.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

References

[1] International Energy Agency (2025) Electricity 2025: Analysis and Forecast to 2027. IEA. https://www.iea.org/reports/electricity-2025

[2] Direction Générale du Trésor (2025) Situation économique et financière de la Côte d'Ivoire. Ministère de l'Économie, des Finances et de la Souveraineté industrielle et numérique. https://www.tresor.economie.gouv.fr/Pays/CI/situation-economique-et-financiere

[3] West African Power Pool (2019) ECOWAS Master Plan for the Development of Regional Power Generation and Transmission Infrastructure 2019-2033: Synthesis. WAPP. https://www.ecowapp.org/sites/default/files/volume_0.pdf

[4] Elabbas, M.A.E., de Vries, L. and Correljé, A. (2023) African Power Pools and Regional Electricity Market Design: Taking Stock of Regional Integration in Energy Sectors. *Energy Research & Social Science*, **105**, Article ID: 103291. https://doi.org/10.1016/j.erss.2023.103291

[5] Bissiri, M., Moura, P., Perez, R.C., Figueiredo, N.C. and da Silva, P.P. (2024) Generation Capacity Expansion Planning with Spatially-Resolved Electricity Demand and Increasing Variable Renewable Energy Supply: Perspectives from Power Pooling in West Africa. *Applied Energy*, **364**, Article ID: 123115. https://doi.org/10.1016/j.apenergy.2024.123115

[6] Correa-Posada, C.M. and Sanchez-Martin, P. (2014) Security-Constrained Optimal Power and Natural-Gas Flow. *IEEE Transactions on Power Systems*, **29**, 1780-1787. https://doi.org/10.1109/tpwrs.2014.2299714

[7] Falchetta, G., Gernaat, D.E.H.J., Hunt, J. and Sterl, S. (2019) Hydropower Dependency and Climate Change in Sub-Saharan Africa: A Nexus Framework and Evidence-Based Review. *Journal of Cleaner Production*, **231**, 1399-1417. https://doi.org/10.1016/j.jclepro.2019.05.263

[8] Kanyako, F., Lamontagne, J., Baker, E., Turner, S. and Wild, T. (2023) Seasonality and Trade in Hydro-Heavy Electricity Markets: A Case Study with the West Africa Power Pool (WAPP). *Applied Energy*, **329**, Article ID: 120214.

https://doi.org/10.1016/j.apenergy.2022.120214

[9] Assoumou, E. and McIsaac, F. (2022) Côte D'ivoire's Electricity Challenge in 2050: Reconciling Economic Development and Climate Commitments. *Energy Policy*, **160**, Article ID: 112681. https://doi.org/10.1016/j.enpol.2021.112681

[10] Yeo, W.M. (2024) A Political Economy Analysis of the Electricity Sector in Côte d'Ivoire. *Energy Research & Social Science*, **118**, Article ID: 103833. https://doi.org/10.1016/j.erss.2024.103833

[11] Koranteng Nkansah, H., Suleman, S., Ackah, I., Amarh, B.A., Eduah, D. and Jinapor, J.A. (2022) Determinants of Electricity Demand in Cote d'Ivoire, Ghana, Nigeria and Senegal. *Energies*, **15**, Article No. 4998. https://doi.org/10.3390/en15144998

[12] Asantewaa, A., Jamasb, T. and Llorca, M. (2022) Electricity Sector Reform Performance in Sub-Saharan Africa: A Parametric Distance Function Approach. *Energies*, **15**, Article No. 2047. https://doi.org/10.3390/en15062047

[13] Bissiri, M., Moura, P., Figueiredo, N.C. and Silva, P.P. (2020) Towards a Renewables-Based Future for West African States: A Review of Power Systems Planning Approaches. *Renewable and Sustainable Energy Reviews*, **134**, Article ID: 110019. https://doi.org/10.1016/j.rser.2020.110019

[14] Carvallo, J.P., Zhang, N., Leibowicz, B.D., Carr, T., Baik, S. and Larsen, P.H. (2023) A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions. Lawrence Berkeley National Laboratory.

[15] Mantegna, G., Huang, Z., Van Caelenberg, G., Frew, B., Lynch, M. and O'Malley, M. (2026) Electric Grid Reliability in an Era of Unprecedented Uncertainty: A Review of Advances in Electric Sector Resource Adequacy Assessment and Planning. *IEEE Transactions on Energy Markets, Policy and Regulation*, **4**, 1-9. https://doi.org/10.1109/tempr.2025.3640116

[16] Dagnachew, A.G., Choi, S. and Falchetta, G. (2023) Energy Planning in Sub-Saharan African Countries Needs to Explicitly Consider Productive Uses of Electricity. *Scientific Reports*, **13**, Article No. 13007. https://doi.org/10.1038/s41598-023-40021-y

[17] International Finance Corporation (2023) IFC Invests in PEPT's First Securitization to Support Access to Electricity in Côte d'Ivoire. https://www.ifc.org/en/pressroom/2023/ifc-invests-in-pepts-first-securitization-to-support-access-to-e

[18] McCluskey, A., Strzepek, K.M. and Rose, A. (2022) Electricity Trade Impacts on Regional Power Pools in Sub-Saharan Africa. *Renewable Energy Focus*, **41**, 33-54. https://doi.org/10.1016/j.ref.2022.01.001

[19] Bissiri, M., Pereira da Silva, P., Moura, P. and Figueiredo, N.C. (2024) Are West Africa's Policy, Planning, and Regulatory Frameworks Missing the Harmonization Piece of the Power Pooling-Renewable Energy Puzzle? *Energy Policy*, **190**, Article ID: 114161. https://doi.org/10.1016/j.enpol.2024.114161

[20] Odetayo, B. and Walsh, M. (2021) A Policy Perspective for an Integrated Regional Power Pool within the Africa Continental Free Trade Area. *Energy Policy*, **156**, Article ID: 112436. https://doi.org/10.1016/j.enpol.2021.112436

[21] Amorim, R. and Villarini, G. (2024) Assessing the Performance of Parametric and Non-Parametric Tests for Trend Detection in Partial Duration Time Series. *Journal of Flood Risk Management*, **17**, e12957. https://doi.org/10.1111/jfr3.12957

[22] Zhou, J., Deitch, M.J., Grunwald, S. and Screaton, E. (2023) Do the Mann-Kendall Test and Theil-Sen Slope Fail to Inform Trend Significance and Magnitude in Hydrology? *Hydrological Sciences Journal*, **68**, 1241-1249. https://doi.org/10.1080/02626667.2023.2212166

[23] Frimpong, B.F., Koranteng, A. and Molkenthin, F. (2022) Analysis of Temperature Variability Utilising Mann-Kendall and Sen's Slope Estimator Tests in the Accra and Kumasi Metropolises in Ghana. *Environmental Systems Research*, **11**, Article No. 24. https://doi.org/10.1186/s40068-022-00269-1

[24] Nafil, A., Bouzi, M., Anoune, K. and Ettalabi, N. (2020) Comparative Study of Forecasting Methods for Energy Demand in Morocco. *Energy Reports*, **6**, 523-536. https://doi.org/10.1016/j.egyr.2020.09.030

[25] Petropoulos, F., Apiletti, D., Assimakopoulos, V., Babai, M.Z., Barrow, D.K., Ben Taieb, S., *et al.* (2022) Forecasting: Theory and Practice. *International Journal of Forecasting*, **38**, 705-871. https://doi.org/10.1016/j.ijforecast.2021.11.001

[26] Tillmanns, M., Schöttler, J. and Praktiknjo, A. (2026) A Review of Probabilistic Resource Adequacy Assessments in Power Systems: Methods, Applications, and Future Challenges. *Energy Policy*, **209**, Article ID: 114924. https://doi.org/10.1016/j.enpol.2025.114924

[27] IEEE Std 1366-2022 (2022) IEEE Guide for Electric Power Distribution Reliability Indices. Technical Report, IEEE.

[28] Toukam, D.O., Meyer, J., Adam, M. and Alsmeyer, F. (2026) Scenario Modelling of Sustainable Electricity Pathways in Côte d'Ivoire: An Open-Source System Framework. *International Journal of Sustainable Energy Planning and Management*, **48**, 107-123. https://doi.org/10.54337/ijsepm.11265

[29] Akpahou, R., Mensah, L.D., Quansah, D.A. and Kemausuor, F. (2024) Energy Planning and Modeling Tools for Sustainable Development: A Systematic Literature Review. *Energy Reports*, **11**, 830-845. https://doi.org/10.1016/j.egyr.2023.11.043

[30] Fields, N., Collier, W., Kiley, F., Caulker, D., Blyth, W., Howells, M., *et al.* (2024) Long-Term Forecasting: A MAED Application for Sierra Leone's Electricity Demand (2023-2050). *Energies*, **17**, Article No. 2878. https://doi.org/10.3390/en17122878

Appendix

Table A1. Installed capacity (MW).

Power plants	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
hydropower												
CIE hydropower												
Ayame 1	20	20	20	20	20	20	20	20	20	20	20	20
Ayame 2	30	30	30	30	30	30	30	30	30	30	30	30
Kossou	174	174	174	174	174	174	174	174	174	174	174	174
Taabo	210	210	210	210	210	210	210	210	210	210	210	210
Buyo	165	165	165	165	165	165	165	165	165	165	165	165
Faye	5	5	5	5	5	5	5	5	5	5	5	5
Total CIE Hydropower	604	604	604	604	604	604	604	604	604	604	604	604
Soubre				275	275	275	275	275	275	275	275	275
Gribo popoli											112	112
Total Hydropower	604	604	604	879	879	879	879	879	879	879	991	991
Change (%)	0.0%	0.0%	0.0%	45.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.7%	0.0%
Solar												
Boundiali solar										30	30	67
Total solar										30	30	67
Change (%)											0.0%	123.3%
Thermal												
Vridi	100	100	100	100	100	100	100	100	100	100	100	100
Ciprel	432	432	543	569	569	569	569	569	569	569	569	569
Azito	296	436	436	441	441	441	471	471	650	724	724	724
Aggreko	200	200	200	210	210	210	210	250	250	250	250	283
Karpower									100	100	100	100
Atinkou										255	255	390
Total thermal	1028	1168	1279	1320	1320	1320	1350	1390	1669	1998	1998	2166
Change (%)	12%	14%	10%	3%	0%	0%	2%	3%	20%	20%	20%	20%
Total hydropower + solar + Thermal	1632	1772	1883	2199	2199	2199	2229	2269	2548	2907	3019	3224
Change (%)	7.3%	8.6%	6.3%	16.8%	0.0%	0.0%	1.4%	1.8%	12.3%	14.1%	3.9%	6.8%

Table A2. Net generation trend (GWh).

Power plants	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
hydropower												
CIE hydropower												
Ayame 1	113	63	75	73	101	117	83	72	78	84	86	58
Ayame 2	135	99	111	102	114	110	101	91	97	44	49	2

Continued

Kossou	81	47	49	77	81	194	229	114	92	157	139	196
Taabo	473	388	453	404	609	779	803	590	603	836	756	799
Buyo	1093	736	822	747	727	663	671	594	617	596	655	724
Faye	5	7	8	1	00	0	0	0	0	0	0	0
Total CIE Hydropower	1901	1340	1517	1404	1633	1863	1886	1461	1488	1717	1685	1779
Soubre hydropower												
MV	0	0	0	3	28	32	39	41	41	42	24	25
HV				623	1277	1559	1429	1107	1316	1422	1413	1380
Total Soubre hydropower	0	0	0	626	1306	1591	1467	1148	1358	1464	1437	1405
Grobo-popoli hydropower												
Gribo-popoli											269	631
Total Gribo-popoli hydropoer											269	631
Total Hydropower	1901	1340	1517	2030	2938	3455	3354	2609	2846	3180	3391	3815
Change (%)	19.3%	−29.5%	13.2%	33.9%	44.7%	17.6%	−2.9%	−22.2%	9.1%	11.8%	6.6%	12.5%
Solar												
Boundiali solar										24	50	101
Total solar										24	50	101
Change (%)											110.5%	101.1%
Thermal												
Vridi	335	295	236	184	111	80	207	403	380	264	357	407
Ciprel	2902	2502	3504	3199	2939	3196	3382	3546	3247	3010	3198	2700
Azito	1382	2696	2994	3069	2833	2744	3140	3261	3738	4003	2882	3819
Aggreko	1632	1685	1680	1313	1009	959	941	1432	1403	1300	1083	1257
Karpower									345	637	1030	815
Atinkou										730	1740	1637
Biovea												7
Total thermal	6251	7177	8414	7766	6893	9679	7670	8642	9113	9944	10,290	10,643
Change (%)	5.6%	14.8%	17.2%	−7.7%	−11.2%	1.3%	9.9%	12.7%	5.5%	9.1%	3.5%	3.4%
Self producers												
SIR outpout	0.6	0.2	0.2	0.3	0.7	0.3	0.3	1.9	0.2	0.3	0.7	1.0
Total self producers	0.6	0.2	0.2	0.3	0.7	0.3	0.3	1.9	0.2	0.3	0.7	1.0
Total interconected grid	8152	8518	9931	9796	9831	10,434	11,024	11,252	11,959	13,149	13,731	14,560
Change (%)	8.4%	4.5%	16.6%	−1.4%	0.4%	6.1%	5.9%	2.1%	6.3%	9.9%		
Isolated and automatic plants												
Conventional isolated plants	0	4	2	2	2	2						
Automatic isolated plants	13	7	6	5	6	6	6	5	3	2	2	3
Total Isolated and Automatic Plants	13	11	8	7	8	8	6	5	3	2	2	3
Total national grid	8166	8529	9939	9803	9840	10,442	11,031	11,257	11,962	13,150	13,733	14,563
Change (%)	8.4%	4.4%	16.5%	−1.4%	0.45	6.1%	5.6%	2.1%	6.3%	9.9%	4.4%	6.0%

Table A3. Net generation mix.

Power plants	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
hydropower	23%	16%	15%	21%	30%	33%	30%	23%	24%	24%	25%	26%
CIE hydropower	23%	16%	15%	14%	17%	18%	17%	13%	12%	13%	12%	12%
Soubre	0%	0%	0%	6%	13%	15%	13%	10%	11%	11%	10%	10%
Gribo popoli											2%	4%
Solar										0.2%	0.4%	0.7%
Boundiali solar										0.2%	0.4%	0.7%
Thermal	77%	84%	85%	79%	70%	67%	70%	77%	76%	76%	75%	73%
Vridi	4%	3%	2%	2%	1%	1%	2%	4%	3%	2%	3%	3%
Ciprel	36%	29%	35%	33%	30%	31%	31%	31%	27%	23%	23%	19%
Azito	17%	32%	30%	31%	29%	26%	28%	29%	31%	30%	21%	26%
Aggreko	20%	20%	17%	13%	10%	9%	9%	13%	12%	10%	8%	9%
Karpower									3%	5%	7%	6%
Atinkou										6%	13%	11%
Self-Producers	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Isolated and automatic plants	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%

Table A4. Domestic electricity consumption (GWh).

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GROSS GENERATION (hydro + solar + thermal)	8202	8608	10,072	9941	9990	10,605	11,204	11,420	12,145	13,343	13,917	14,720
SIR Output (HV)	0.6	0.2	0.2	0.3	0.7	0.3	0.3	1.9	0.2	0.3	0.7	1.0
Imports from VRA/SONABEL/EDM/CLSG (Unscheduled and Emergency)	20	17	7	21	78	77	149	197	267	269	382	708
Exports to VRA/CEB/SONABEL/EDM/LEC/CLSG	902	872	1655	1247	1156	1255	1333	887	973	1052	730	797
Exports-Imports	883	855	1648	1225	1078	1179	1184	690	706	784	349	90
Gross Domestic Consumption (Interconnected Grid)	7319	7753	8424	8716	8913	9427	10,020	10,732	11,439	12,559	13,570	14,631
Change (%)	8.0%	5.9%	8.7%	3.5%	2.3%	5.8%	6.3%	7.1%	6.6%	9.8%	8.0%	7.8%
Gross Generation-Isolated Plants	13	10	8	7	7	7	6	5	3	2	2	1
Imports from NEDCo	0	6	12	14	16	17	3	1	0	0	0	0
Gross Domestic Consumption (Including Isolated Grids)	7333	7769	8444	8738	8936	9451	10,029	10,738	11,442	12,561	13,572	14,635
Change (%)	8.0%	5.9%	8.7%	3.5%	2.3%	5.8%	6.1%	7.1%	6.6%	9.8%	8.0%	7.8%

Table A5. Cross-border electricity flows.

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Exports (GWh)												
GRIDCo (VRA)	52	227	575	242	141	127	58	43	36	80	57	11
CEB	119	13	222	73	0	0	0	0	0	0	0	0

Continued

SONABEL	434	382	571	583	561	506	489	412	281	297	202	338
EDM HTB	291	244	276	333	437	602	762	403	489	256	111	102
EDM HTA	4	4	5	6	7	7	7	7	8	9	10	11
LEC	2	2	7	8	10	13	18	21	26	28	37	37
CLSG								1	134	383	313	299
Total Exports	902	872	1655	1247	1156	1255	1333	887	973	1052	730	797
Imports (GWh)												
GRIDCo (VRA, GENSER)	19.6	17.2	604	21.2	77.5	76.4	149.4	197.0	265.6	264.7	376.7	691.3
SONABEL	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.2	1.1	0.5	1.1	0.4
EDM	0.1	0.1	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.0
CLSG								0.0	0.1	2.4	4.0	16.0
Total Imports	20	17	7	21	78	77	149	197	267	269	382	708

Table A6. Cross-border electricity sales and purchases.

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cross-Border Electricity Sales (GWh)												
VRA	46	210	568	221	63	51	0	0	36	0	0	0
CEB	119	13	222	73	0	0	0	0	0	0	0	0
SONABEL	434	382	571	583	561	505	489	412	280	296	201	338
EDM HTB	291	244	276	333	437	602	762	403	488	255	111	102
EDM HTA	4.4	4.4	4.7	6.3	6.8	7.5	6.5	8.4	8.2	9.3	9.8	10.6
LEC	1.8	2.1	6.5	8.5	10.2	13.3	18.0	20.7	25.7	28.2	36.8	37.1
CLSG								1.4	133.6	387.9	311.4	298.9
Total Cross-Border Sales	897	855	1648	1225	1078	1179	1275	845	971	977	670	787
Change (%)	9.4%	−4.6%	92.8%	−25.7%	−12.0%	9.3%	8.2%	−33.7%	15.0%	0.5%	−31.4%	17.4%
Cross-Border Electricity Purchases (GWh)												
VRA	13.9	0.0	0.0	0.0	0.0	0.0	91.2	153.7	265.6	245.4	42.7	75.3
NEDCO	0.0	5.8	12.2	14.5	16.0	16.9	2.6	1.3	0.0	0.0	0.0	0.0
GENSER											334.1	615.2
Total Cross-Border Purchases	13.9	5.8	12.2	14.5	16.0	16.9	93.8	154.9	265.6	245.4	376.8	690.5
Change (%)	−47.5%	−58.2%	110.0%	18.3%	10.7%	5.5%	454.4%	65.1%	71.4%	−7.6%	53.6%	83.3%

Table A7. Grid efficiency.

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Transmission Efficiency	93.6%	93.5%	92.9%	92.3%	94.0%	95.2%	94.6%	94.7%	94.0%	93.9%	94.4%	95.00%
Distribution Efficiency	82.4%	83.3%	84.9%	84.7%	85.0%	87.0%	87.0%	89.1%	91.3%	91.1%	90.3%	89.38%
Generation-to-Transmission Efficiency	93.0%	92.5%	91.6%	90.9%	92.5%	93.7%	93.1%	93.0%	92.6%	92.5%	93.2%	94.0%
Transmission-to-Distribution Efficiency	79.1%	79.6%	81.4%	80.1%	81.6%	84.4%	83.9%	84.9%	86.5%	86.2%	85.7%	85.4%
Overall Efficiency	78.59%	78.78%	80.30%	78.95%	80.32%	83.08%	82.54%	83.67%	85.02%	84.99%	84.56%	84.54%

Table A8. Quality of supply.

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy Not Supplied (MWh)												
HV			8153	6594	8029	6800	5732	19,167	15,619	20,080	13,656	10,851
MV			13,571	10,995	90,078	9569	9683	13,520	12,253	14,289	15,265	17,308
Other			2208	3702	3739	2180	1816	9308	6948	4459	8801	1068
Total Energy Not Supplied			23,932	21,290	20,847	18,549	17,231	41,995	34,820	38,828	37,723	29,227
Energy Not Supplied by Network Level (%)												
HV			34%	31%	39%	37%	33%	46%	45%	52%	36%	37%
MV			57%	52%	44%	52%	56%	32%	35%	37%	40%	59%
Other			9%	17%	18%	12%	11%	22%	20%	11%	23%	4%
Average Outage Duration (hours)	40.0	44.6	27.7	23.8	22.3	18.6	16.4	17.9	29.9	29.4	26.2	18.6
System Average Interruption Duration Index (SAIDI), hour		58.1	14.6	16.4	14.7	12.5	10.8	ND	19.6	19.5	17.6	10.0
System Average Interruption Frequency Index (SAIFI)		42	24	21	18	18	20	ND	23	22	22	18

Table A9. Customer growth.

Number of Customers	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Low Voltage	1,311,741	1,428,317	1,626,653	1,892,711	2,191,290	2,532,418	2,909,633	3,248,556	3,639,780	4,040,965	4,580,256	5,271,162
Including PEPT	196	31,808	175,561	359,508	565,039	768,030	1,022,856	1,225,646	1,476,779	1,738,457	2,157,047	2,118,649
High Voltage	4096	4462	4790	5115	5435	5736	6055	6412	6939	7594	7696	8121
National	1,315,837	1,432,779	1,631,443	1,897,826	2,196,725	2,538,154	2,915,688	3,254,968	3,646,619	4,048,259	4,587,952	5,282,283
Change (%)	7.5%	8.9%	13.9%	16.3%	157%	15.5%	14.9%	11.6%	12.0%	11.0%	13.3%	15.1%
PEPT Contribution to Growth in the Number of Low-Voltage Customers (%)		2.4%	10.1%	11.3%	10.9%	9.3%	10.1%	7.0%	7.7%	7.2%	10.4%	12.3%

Table A10. Number of customers by tariff category.

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Low Voltage												
Social Residential	519,146	543,926	592,189	714,685	833,744	1,060,860	1,285,308	1,539,531	1,857,410	2,058,971	2475,655	3,040,093
General Residential 5A	363,513	414,647	475,543	516,513	553,560	586,998	617,603	604,040	581,166	55,644	521,222	467,479
General Residential	276,528	306,661	389,766	482,621	609,665	682,826	781,102	866,854	962,282	1,181,846	1,329,831	1,503,878
General Business	138,083	147,500	152,777	161,897	176,528	182,564	205,181	212,401	215,351	218,730	226,952	234,283

Continued

Contract Tariff	5062	5386	5506	5654	5820	5965	6865	5973	6025	6136	6296	6442
Public Lighting	8104	8822	9446	9807	10,369	11,557	12,787	14,044	15,831	17,158	18,621	20,200
Free Service	1306	1375	1426	1434	1604	1648	787	1713	1715	1680	1679	1787
Total Low Voltage	1,311,741	1,428,317	1,626,653	1,892,711	2,191,290	2,532,418	2,909,633	3,248,556	3,639,780	4,040,965	4,580,256	5,274,262
High Voltage												
Short Use	62	67	66	61	58	60	59	57	62	57	52	54
General Use	3780	4138	4458	4788	5110	5346	5644	5992	6402	6861	7260	7684
Long Use	199	206	214	208	207	268	293	300	310	309	312	312
Free Service	48	49	49	56	58	59	55	59	61	61	65	64
High Voltage	2	2	2	2	2	3	4	4	4	6	7	7
Special Textile Complex	5	0	1	0	0	0	0	0	0	0	0	0
Total High Voltage	4096	4462	4790	5115	5435	5736	6055	6412	6839	7294	7696	8121

Table A11. Number of customers by regional directorate (RD).

Items	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Abidjan												
DRAS	122,349	128,571	175,918	248,901	306,538	333,820	347,491	359,893	375,152	393,902	409,709	420,660
DRYOP	182,898	197,959	232,361	276,302	329,484	367,765	383,579	402,878	422,508	442,869	458,916	480,564
DRAN	166,305	182,620	223,667	251,780	288,683	327,797	348,360	374,490	404,258	434,480	466,121	495,218
DRABO	118,021	153,666	173,956	203,360	235,829	290,470	314,831	345,343	373,824	406,237	434,231	470,861
Total Abidjan	589,573	662,816	805,902	980,343	1,160,354	1,319,852	1,394,261	1,482,604	1,575,742	1,677,488	1,768,977	1,867,303
Inland Regions												
DRE	84,455	95,736	102,306	115,774	129,995	153,570	193,311	212,381	233,399	256,932	295,552	356,014
DRSO	130,489	140,587	116,624	128,794	140,699	161,432	196,948	237,353	280,788	312,193	362,828	431,788
DRLO			33,951	36,906	39,691	57,259	85,928	104,590	117,426	156,950	161,946	205,438
DRBC	84,597	64,278	67,069	69,980	81,089	91,799	113,766	124,237	136,819	186,703	195,538	234,306
DRSE	59,763	64,002	68,965	74,196	82,317	95,789	120,543	138,491	162,462	133,178	217,182	251,986
DRC	80,142	87,909	90,202	98,091	105,493	120,690	158,271	189,284	22,921	256,428	302,519	357,376
DRCO	76,601	84,670	94,562	104,916	114,750	130,819	161,085	204,004	254,409	290,941	342,360	415,699
DRN	69,562	76,094	81,543	98,525	121,661	151,475	187,494	218,321	260,445	307,740	373,157	457,263
DRO	58,518	64,075	67,525	75,636	86,733	99,866	113,834	139,110	180,654	211,977	258,059	340,974
DRCS	82,518	92,612	102,794	114,665	133,763	155,603	190,347	204,593	221,554	257,729	309,834	364,136
Total Inland Regions	726,264	769,963	825,541	917,483	1,036,191	1,218,302	1,521,427	1,772,364	2,070,877	2,370,771	2,818,975	3,414,980
National	1,315,837	1,432,779	1,631,443	1,897,826	2,196,725	2,538,154	2,915,688	3,254,968	3,646,619	4,048,259	4,587,952	5,282,283