Reducing Energy Shortages and External Dependence in Tunisia: A Renewable Hybrid Energy Framework Through 2040

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***Abstract*—Tunisia's power system faces increasing exposure to declining domestic hydrocarbon production, imported natural gas, and regional electricity purchases. Official statistics show that primary-energy resources decreased from 4.436 Mtoe in 2023 to 3.378 Mtoe in 2025, while energy independence fell from 49% to 35%. This study updates the national baseline through May 2026 and develops a transparent screening framework for renewable-based hybrid-system development through 2040. Electricity demand is expressed on a consistent supplied-energy basis. Under the reference growth case and a 12% system-loss target, 2040 end-use demand is estimated at 25.83 TWh and the corresponding supplied-energy requirement at 29.35 TWh, with a peak load of 7.46 GW. The observed 2023 wind-fleet capacity factor of approximately 16.9% is adopted as the conservative onshore-wind assumption, with 25% and 32% examined as sensitivities. Under a common 8% integration allowance, the business-as-usual, balanced, and accelerated scenarios provide approximately 28.4%, 60.0%, and 80.1% renewable electricity, respectively. A duration-constrained firm-capacity screen shows that the balanced configuration does not provide a positive evening reserve margin under the reference and high-demand cases without additional dependable flexibility. The results support renewable hybridization as a promising energy-security pathway but show that annual energy sufficiency alone is insufficient to demonstrate resource adequacy. Chronological dispatch, network-constrained reliability, and full techno-economic optimization remain necessary before investment decisions.**

Keywords*—Battery energy storage; capacity adequacy; ELMED; energy security; hybrid energy system; renewable integration; Tunisia; wind capacity factor

I. Introduction

Tunisia's electricity system faces declining domestic hydrocarbon production, persistent natural-gas dependence, regional electricity purchases, and growing demand. Official energy statistics indicate that primary-energy resources declined from 4.436 Mtoe in 2023 to 3.378 Mtoe in 2025, while demand increased from 9.148 to 9.684 Mtoe. The corresponding energy-independence rate fell from 49% to 35% [1]–[3]. During January–May 2026, energy independence remained only 34%, although renewable electricity increased to 9.0% of generation and residential rooftop photovoltaic capacity reached 485 MW [4].

The electricity system remains dominated by natural gas. STEG reported 5,982 MW of national installed capacity in 2023, mostly combined-cycle and open-cycle gas generation [5], [6]. Cross-border purchases from Algeria and Libya supplied 11% of domestic requirements in 2023, 14% in 2024, and 11% in 2025 [1]–[3]. The planned 600 MW Tunisia–Italy ELMED interconnector is intended to strengthen trade, resilience, and renewable integration [7], [8]. These developments create an opportunity to reassess how domestic solar, wind, storage, demand response, retained flexible gas capacity, and interconnection can be combined through 2040.

Tunisia's renewable-energy policy and national strategy to 2035 place energy security, renewable deployment, and low-carbon development at the center of policy [9]–[11]. However, a strategic target alone does not establish the hourly deliverability, firm-capacity contribution, storage requirements, or external-dependence implications of a high-renewable portfolio. This study therefore develops a national screening framework that links the latest 2023–May 2026 official statistics with internally consistent energy-balance, capacity-adequacy, storage, interconnection, and sensitivity calculations for 2040. The framework is not an official STEG expansion plan and is not presented as a bankable investment model.

The framework is built around four methodological principles. First, 2040 electricity requirements are evaluated on a consistent supplied-energy basis that distinguishes end-use consumption from the energy supplied by the system. Second, the central onshore-wind capacity factor is anchored to observed 2023 fleet performance, while higher values are treated as sensitivity cases. Third, scenario outcomes are derived from explicit capacity and capacity-factor assumptions, and chronological curtailment is claimed only when simulated. Fourth, firm-capacity contributions are constrained by storage duration and system-stress conditions rather than by nameplate power alone.

II. Literature Review and Research Gap

A. Energy Security and National Planning

IRENA identifies Tunisia's declining domestic hydrocarbon production and natural-gas-dominated electricity mix as persistent energy-security vulnerabilities [12]. World Bank analyses similarly emphasize renewable investment, network strengthening, and regional integration to improve affordability and security [7], [8], [13]. The national energy strategy to 2035 provides the policy context for renewable scaling and efficiency [10], [11], while STEG and ONEM reports provide the operational and statistical baseline used in this study [1]–[6].

B. Peer-Reviewed Hybrid and Power-System Studies

Peer-reviewed work provides a more detailed technical benchmark than policy documents alone. Dhakouani et al. developed an OSeMOSYS long-term optimization model of the Tunisian power system and showed that explicit national constraints and interconnection representation materially affect expansion results [14]. Fragkos and Zisarou used the MENA-EDS framework to evaluate Tunisia's Nationally Determined Contribution and long-term low-emission transition, emphasizing renewable expansion, electrification, and efficiency [15].

At project scale, El Alimi et al. optimized stand-alone PV, wind, and battery configurations for a Tunisian residential case [16], while Maatallah et al. evaluated PV–wind–diesel systems with storage in Bizerte using HOMER [17]. At system-operation scale, Mansouri et al. examined reserve and frequency response under increasing renewable penetration in the Tunisian grid and demonstrated the importance of primary reserve [18]. Regional TIMES-MAGe modeling indicates that storage and electricity trade can materially influence Maghreb decarbonization pathways and system cost [19]. Most recently, Berriri et al. used a network-constrained openTEPES representation of Tunisia and showed that storage siting, transmission constraints, interconnection availability, demand, and renewable chronology strongly influence curtailment and energy-not-served outcomes [20].

C. Research Gap and Contribution

The literature demonstrates that chronological, economic, and network-constrained optimization is essential for investment-grade planning. Accordingly, this paper contributes a transparent 2040 national screening framework that connects the latest official 2023–May 2026 energy-security indicators with supplied-energy requirements, renewable-resource performance, storage duration, firm capacity, demand response, flexible gas generation, and interconnection. The framework identifies where a proposed hybrid portfolio is internally consistent and where additional chronological or economic analysis remains necessary. This positioning avoids presenting the study as a substitute for detailed capacity-expansion, production-cost, or AC power-flow modeling.

TABLE I. ENERGY AND ELECTRICITY INDICATORS, 2023–2026

Indicator	2023	2024	2025	Jan 2026–May 2026
Primary resources (Mtoe)	4.436	3.738	3.378	1.306
Primary demand (Mtoe)	9.148	9.134	9.684	3.843
Energy independence	49%	41%	35%	34%
Electricity production (GWh)	19,729*	19,393**	20,535	7,506
Import share of requirements	11%	14%	11%	9%
Renewable generation share	4.3%	5.1%	6.0%	9.0%
Solar generation share	2.5%	3.26%	4.12%	8.18%
Wind generation share	1.7%	1.8%	1.3%	0.8%
Residential rooftop PV (MW)	217	267	420	485

Source: ONEM bulletins [1]–[4]. *2023 includes PV self-generation. **The 2025 ONEM bulletin reports the 2024 comparator as 19,442 GWh. All 2026 values cover January–May only and exclude the summer peak.

Table I shows that primary-energy independence continued to deteriorate even as renewable deployment accelerated. The important planning implication is that solar growth alone has not yet displaced the structural role of gas and imports; complementary wind, storage, flexible demand, and firm-capacity resources therefore remain necessary.

III. DATA AND METHODOLOGY

A. Baseline Boundary and Consistent Energy Balance

The detailed 2023 electricity baseline is taken from the STEG annual report [5], while the multi-year trend uses official ONEM bulletins [1]–[4]. STEG reports 17.842 TWh of billed consumption, 21.744 TWh of net electricity available after system use, and 3.902 TWh of reported transmission and distribution losses in 2023 [5]. Because billed consumption and supplied generation represent different system boundaries, the methodology distinguishes end-use electricity from the energy supplied to the system.

$$E_{\mathrm{end},y} = E_{\mathrm{bill},2023}(1+g_e)^{y-2023} \quad (1)$$

$$E_{\mathrm{sup},y} = \frac{E_{\mathrm{end},y}}{1-L_y} \quad (2)$$

where $E_{end,y}$ is end-use electricity demand, $E_{bill,2023}$ is the 2023 billed-consumption reference, g_e is the annual end-use demand growth rate, and L_y is the combined loss fraction. The 2040 screening uses a 12% loss target as an author-proposed planning objective. This treatment avoids comparing generation at the supply boundary with consumption measured after losses.

Fig. 1 summarizes the methodological workflow adopted in this study. The analysis begins with official baseline data from STEG and ONEM, supported by IRENA, World Bank, and peer-reviewed sources. These inputs define the 2023 baseline and update Tunisia's energy-security trend through May 2026. The methodology then projects end-use electricity demand, supplied-energy requirements, and peak load to 2040 under low, reference, and high growth cases. Renewable and flexibility options are represented through explicit assumptions for solar PV, onshore and offshore wind, hydropower, battery energy storage, pumped storage, demand response, and interconnection support. Three development scenarios are evaluated using renewable-energy balance, firm-capacity, and reserve-margin

screening. Finally, one-at-a-time sensitivity analysis is applied to key uncertain parameters to derive planning implications, implementation priorities, and directions for future chronological and techno-economic analysis.

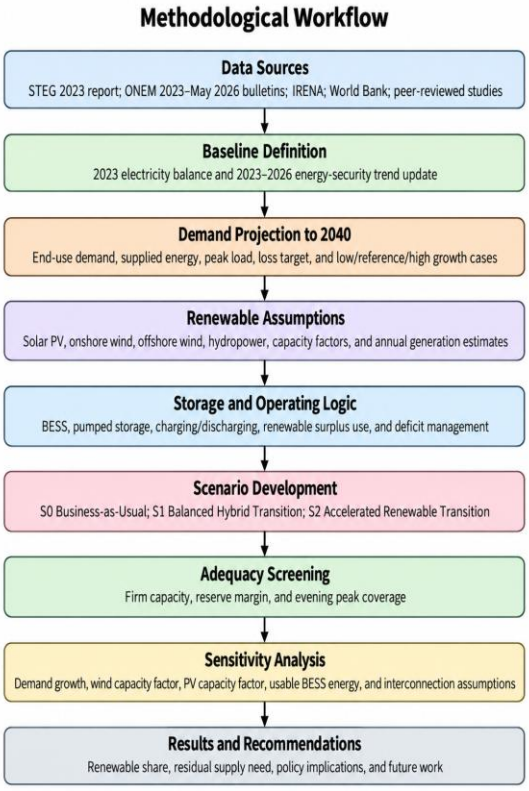

Fig. 1. Methodological workflow for the Tunisia hybrid-energy screening framework.

B. Demand and Peak Projection

where P_{2023} is the estimated unsuppressed 2023 peak of 5.066 GW and g_P is the annual peak-growth rate. Table II defines low, reference, and high growth assumptions and applies them consistently to end-use demand and peak load.

$$P_y = P_{2023}(1 + g_P)^{y-2023} \quad (3)$$

TABLE II. DEMAND-GROWTH ASSUMPTIONS

Case	Energy growth	Peak growth	Purpose
Low	1.5%/yr	1.8%/yr	Efficiency / slower growth
Reference	2.2%/yr	2.3%/yr	Central screening
High	3.0%/yr	3.2%/yr	Stress case

C. Renewable-Generation Assumptions

The 2023 Tunisian wind fleet produced 338 GWh from 229 MW of installed wind capacity [5]. The corresponding observed capacity factor is:

$$CF_{\text{wind},2023} = \frac{338\times10^3}{229\times8760} = 0.169 \quad (4)$$

Accordingly, a 16.9% capacity factor was used as a conservative central value for onshore wind. Onshore-wind capacity factors of 25% and 32% are considered as sensitivity cases representing improved future project performance. Utility-scale PV is screened at 22%, offshore wind at 42%, and existing hydropower at 18%. Annual generation is calculated as:

$$E_i = P_i\, CF_i\, 8760 \quad (5)$$

These values are screening assumptions, not substitutes for site-specific resource assessment. The 42% offshore-wind assumption is particularly uncertain because Tunisia does not yet have a mature operating offshore fleet.

D. Storage and Operating Logic

The balanced pathway uses a 2.5 GW/10 GWh battery system and a 0.5 GW/4 GWh pumped-storage option. Battery round-trip efficiency is assumed to be 88% and pumped-storage efficiency 78%. In chronological operation, renewable generation first supplies load; renewable surplus charges storage subject to power and energy limits; remaining surplus is exported where feasible and otherwise curtailed; and deficits are met sequentially by storage discharge, demand response, flexible gas generation, and permitted imports.

$$E_{\text{BESS}} = P_{\text{BESS}} t_{\text{BESS}} \quad (6)$$

$$P_{\text{RE}}(t) = P_{\text{PV}}(t) + P_{\text{W}}(t) + P_{\text{H}}(t) \quad (7)$$

$$E(t+1) = E(t) + \eta_{\text{ch}} P_{\text{ch}}(t)\Delta t - \frac{P_{\text{dis}}(t)}{\eta_{\text{dis}}}\Delta t \quad (8)$$

Equation (8) represents the storage state-of-energy update. A full chronological implementation would additionally impose minimum and maximum state of charge, charge/discharge power limits, import limits, unit availability, and network constraints. In the present annual screening, an 8% integration allowance is applied to gross renewable generation to represent curtailment, storage-conversion losses, and operational constraints. It is not interpreted as a calculated chronological curtailment rate.

E. Firm Capacity and Reliability Screening

In Eq. (9), C_g, C_{RE}, C_B, C_P, C_{DR}, and C_{INT} are the dependable contributions of gas, variable renewable generation, batteries, pumped storage, demand response, and interconnection, respectively. Tunisia can experience substantial evening electricity demand, when solar PV output falls sharply or becomes unavailable. Therefore, the system must sustain enough dependable capacity to meet demand after sunset. The analysis assumes 95% availability for 3.75 GW of retained gas capacity, a 10% capacity credit for wind, and no PV contribution during the evening period. It also assumes 90% usable battery energy, 500 MW of pumped storage, 500 MW of dispatchable demand response, and 300 MW of interconnection support. These values are used as screening assumptions and should be refined in future studies using chronological and probabilistic capacity assessments.

$$C_{\text{firm}} = C_g + C_{RE} + C_B + C_P + C_{DR} + C_{INT} \quad (9)$$

$$P_{\text{BESS,firm}} = \min\left(P_{\text{BESS}}, \frac{E_{\text{BESS,usable}}}{H_{\text{critical}}}\right) \quad (10)$$

$$RM = \frac{C_{\text{firm}} - P_{\text{peak}}}{P_{\text{peak}}} \times 100\% \quad (11)$$

The stress-interval duration is critical. The conservative evening screen assumes 95% availability for 3.75 GW of retained gas capacity, 10% wind capacity credit, zero PV contribution after sunset, 90% usable battery energy, 500 MW pumped storage, 500 MW dispatchable demand response, and 300 MW of conservative interconnection support. These values are screening assumptions and should be refined in future studies using chronological data and probabilistic capacity-value analysis, if pertinent data are available.

$$RF = \frac{E_{\text{RE,delivered}}}{E_{\text{sup}}} \times 100\% \quad (12)$$

F. Scenario Definition

Table III specifies the three development scenarios. To make the renewable-energy calculation reproducible, wind capacity is separated explicitly into onshore and offshore components. The S0 and S2 wind splits are author-proposed scenario definitions, not official national targets.

TABLE III. 2040 SCENARIO DEFINITIONS

Resource	S0 BAU	S1 Balanced	S2 Accelerated
Solar PV	3.5 GW	7.0 GW	9.0 GW
Onshore wind	1.5 GW	2.5 GW	3.0 GW
Offshore wind	0 GW	0.5 GW	1.0 GW
Battery storage	0.5 GW / 2 GWh	2.5 GW / 10 GWh	4 GW / 20 GWh
Pumped storage	0GW	0.5 GW / 4 GWh	0.75 GW
Demand response	Limited	0.5 GW	≥0.5 GW

G. Sensitivity and Economic Scope

Sensitivity analysis varies end-use demand growth, onshore-wind capacity factor, PV capacity factor, and usable battery energy. A complete economic optimization is outside the scope of this screening because the study framework does not include a consistent national dataset for technology CAPEX, fixed and variable operating costs, fuel prices, financing assumptions, battery replacement costs, and import/export prices. Economic feasibility is therefore not claimed. For a subsequent techno-economic stage, net present cost and levelized cost of electricity can be calculated using Eqs. (13) and (14), where $C_{net,y}$ combines annual O&M, fuel, imports, replacement expenditure, and export revenues on a consistent net-cost basis.

$$NPC = C_0 + \sum_{y=1}^{N} \frac{C_{\text{net},y}}{(1+r)^y} \quad (13)$$

$$LCOE = \frac{NPC}{\sum_{y=1}^{N} \frac{E_{\text{served},y}}{(1+r)^y}} \quad (14)$$

IV. RESULTS

A. 2040 Demand Requirement

Using the 2023 billed-consumption reference of 17.842 TWh, the end-use and supplied-energy requirements shown in Table IV are obtained. The reference case reaches 25.83 TWh of end-use demand but requires 29.35 TWh of supplied electricity when the 12% loss target is applied.

The high-growth case reaches 33.51 TWh of supplied energy and an 8.65 GW peak, illustrating the additional system burden associated with faster demand growth.

TABLE IV. 2040 ELECTRICITY REQUIREMENTS

Case	End-use demand	Supplied energy	Peak load
Low	22.98 TWh	26.11 TWh	6.86 GW
Reference	25.83 TWh	29.35 TWh	7.46 GW
High	29.49 TWh	33.51 TWh	8.65 GW

B. Scenario Results

Table V evaluates S0, S1, and S2 using the same capacity-factor assumptions and the same 8% integration allowance. Each annual renewable share is directly reproducible from the stated capacities and assumptions. Chronological curtailment is not reported because it has not been simulated.

Under the moderate historical-wind assumption, S1 supplies approximately 60% of reference-case electricity from renewable resources. S2 reaches approximately 80.1% but requires a substantially larger renewable and storage portfolio. These results highlight the importance of a consistent demand denominator and an evidence-based wind capacity factor.

TABLE V. TUNISIA 2040 SCENARIO SCREENING

Indicator	S0	S1	S2
Gross RE generation	9.06 TWh	19.13 TWh	25.56 TWh
Integration allowance	0.73 TWh	1.53 TWh	2.05 TWh
Delivered RE	8.34 TWh	17.60 TWh	23.52 TWh
Reference supplied demand	29.35 TWh	29.35 TWh	29.35 TWh
Renewable share	28.4%	60.0%	80.1%
Residual supply need	21.01 TWh	11.75 TWh	5.83 TWh
Chronological curtailment	Not calculated	Not calculated	Not calculated

RE = renewable electricity. The 8% integration allowance is a screening deduction for curtailment, storage-conversion losses, and operating constraints; it is not a chronological curtailment result.

C. Capacity Adequacy

For S1, a 2.5 GW/10 GWh battery with 90% usable energy can sustain 2.25 GW over a four-hour critical evening period. Combined with 95% availability of 3.75 GW retained gas capacity, 0.3 GW dependable wind, 0.5 GW pumped storage, 0.5 GW demand response, and 0.3 GW conservative interconnection support, the evening firm-capacity screen yields approximately 7.41 GW. Table VI shows this is adequate only in the low-growth case and provides no positive planning margin in the reference or high-growth cases.

The capacity-adequacy screen indicates that S1 is not resource-adequate under all demand-growth cases. Under reference or high growth, S1 needs additional dependable capacity, longer-duration storage, greater demand response, or stronger contracted interconnection support to demonstrate a conventional positive reserve margin.

TABLE VI. CONSERVATIVE EVENING CAPACITY-ADEQUACY SCREEN

Case	2040 peak	Firm capacity	Reserve margin
Low	6.86 GW	7.41 GW	+8.0%
Reference	7.46 GW	7.41 GW	−0.6%
High	8.65 GW	7.41 GW	−14.3%

D. Sensitivity and Uncertainty

The two most influential uncertainties in the annual screening are demand growth and wind performance. Table VII shows the renewable share of S1 under separate one-at-a-time variations. At the reference supplied-energy requirement, improving the onshore-wind capacity factor from 16.9% to 25% raises the renewable share from 60.0% to 65.5%, and a 32% wind factor raises it to 70.3%. Conversely, high demand growth reduces the S1 renewable share to 52.5% even before additional reliability requirements are considered.

TABLE VII. S1 ONE-AT-A-TIME SENSITIVITY RESULTS

Sensitivity	Low case	Reference	High case
Demand growth	67.4% (1.5%)	60.0% (2.2%)	52.5% (3.0%)
Onshore wind CF	60.0% (16.9%)	65.5% (25%)	70.3% (32%)
PV CF	56.1% (20%)	60.0% (22%)	63.8% (24%)
Usable BESS energy / RM	80% / −3.9%	90% / −0.6%	100% / +2.8%

Each row varies one parameter family while holding the remaining central assumptions fixed. RM values refer to the reference-growth evening capacity screen.

E. Interconnection and Thermal-Fleet Screening

ELMED should be treated as a flexibility resource rather than automatically as 600 MW of firm domestic capacity. Table VIII separates physical transfer capability from the capacity that may be relied upon during scarcity. This distinction accounts for link outages, coincidence scarcity, high import prices, or market restrictions.

Thermal retirement is assessed using a criteria-based screen rather than a fixed calendar. Candidate units should be evaluated using annual capacity factors, heat rate, variable operating cost, forced-outage rate, maintenance burden, emissions, black-start or voltage-support capability, and whether replacement firm capacity has already entered service. The 660 MW steam fleet generated only 623 GWh in 2023, corresponding to about 10.8% utilization [5], so it is a logical candidate for detailed retirement assessment but not for automatic retirement based solely on utilization.

TABLE VIII. ELMED OPERATING POLICIES FOR SENSITIVITY ANALYSIS

Policy	Operating treatment	Firm capacity in screen
E1 Emergency only	Contingency support; not scheduled for routine adequacy	0 MW
E2 Conservative support	Limited contracted scarcity support	300 MW
E3 Economic trading	Import/export according to market conditions	Only contracted firm amount

V. DISCUSSION

A. Technical Interpretation

The results show that Tunisia has sufficient renewable-resource potential to reduce external dependence, but annual energy potential must not be confused with dependable system capacity [21]. The S1 case supplies approximately 60% of reference-case annual electricity from domestic renewable generation under conservative wind assumptions, while S2 reaches about 80%. However, the reference and high-growth evening screens remain short of a positive reserve margin. Storage duration, demand response, efficient retained gas capacity, and firm interconnection therefore have direct reliability value.

The sensitivity results also explain why recent Tunisian studies emphasize chronology and network deliverability. Berriri et al. show that storage location, transmission exposure, renewable-profile stress, and interconnection availability can materially change curtailment and energy-not-served outcomes [20]. Mansouri et al. similarly demonstrate the importance of reserve response as renewable penetration increases [18]. The present annual screening is therefore best interpreted as a transparent precursor to chronological planning, not a replacement.

B. Economic Implications

The study does not demonstrate economic feasibility because it has not consistently modeled CAPEX, fixed and variable O&M, fuel prices, financing, storage replacement, and import/export prices. The economic discussion is therefore limited to implications rather than conclusions. Potential benefits include avoided gas imports, lower emergency-purchase exposure, reduced shortage risk, and the system value of flexibility. These benefits must be compared with the lifecycle costs of renewable generation, BESS, pumped storage, transmission reinforcement, demand-response infrastructure, and retained firm capacity using a common financial framework such as Eqs. (13) and (14).

C. Institutional and Policy Implications

A high-renewable transition requires coordinated implementation, not generation procurement alone. IRENA identifies institutional complexity, financing constraints, and regulatory clarity as important barriers [12]. The national strategy to 2035 and the ELMED program provide an enabling policy direction [7], [8], [10], [11]. Still, implementation requires transparent grid-connection procedures, clear storage ownership and remuneration rules, bankable procurement arrangements, cost-reflective signals with targeted social protection, improved forecasting, and publication of periodically updated system plans.

VI. RECOMMENDATIONS

Table IX summarizes the proposed implementation measures. It also shows the basis for each recommendation. Some actions are supported by external projects and references. Others come from scenario analysis or are proposed by the authors. This distinction clarifies the source of each recommendation.

TABLE IX. IMPLEMENTATION RECOMMENDATIONS AND EVIDENCE BASIS

Measure	Timing	Evidence classification
Complete ELMED and related grid reinforcement	2026–2030	Externally documented [7], [8]
Repower aging wind and develop site-specific resource assessment	2026–2030	Author recommendation; data-supported
Deploy initial grid BESS and DR pilots	2026–2030	Author recommendation
Expand PV/wind with network studies	2030–2035	Scenario-derived / author proposed
Apply criteria-based steam/OCGT retirement	2030–2040	Author recommendation based on unit screening
Target ≥0.5 GW dispatchable demand response	By 2040	Scenario-derived
Update expansion plans every two years	2026–2040	Author recommendation

Short-term actions should focus on data quality and system flexibility. Publish unit-level plant availability and heat-rate data. Renewable forecasting should be improved. Expand site-specific wind measurements. Clear BESS grid-code and remuneration rules are needed. Demand-response pilot programs should be initiated. Grid reinforcement associated with ELMED should also be completed.

Medium-term planning should use chronological capacity-expansion and production-cost models. These models should identify the least-cost mix of renewable generation, storage, flexible gas capacity, demand response, and interconnection.

Long-term plant retirement should be gradual. Retire thermal units only when sufficient replacement firm capacity is available. Essential ancillary services must also remain available.

VII. LIMITATIONS AND FUTURE WORK

This study is a national screening framework. It does not perform hourly unit commitment, probabilistic loss-of-load assessment, chronological renewable curtailment, AC power flow, endogenous transmission expansion, or full lifecycle cost optimization. The 2026 official observations cover January–May and exclude the summer peak. Capacity factors for future projects are uncertain, especially offshore wind, and the 8% annual integration allowance is a screening parameter rather than a simulated outcome.

Future research should therefore use measured or validated hourly demand, solar, wind, hydro, outage, interconnection, and network data in a production-cost and capacity-expansion framework. Priority tasks include probabilistic capacity-credit estimation for PV, wind, BESS, and demand response; endogenous BESS duration and degradation optimization; network-constrained dispatch; explicit gas and electricity-import price scenarios; battery replacement and financing; ELMED import/export co-optimization; and climate-adjusted demand and hydrology. Tools such as PLEXOS, PyPSA, TIMES, HOMER Grid, EnergyPLAN, OSeMOSYS, or openTEPES can support these extensions, depending on the planning question.

VIII. CONCLUSION

Tunisia's latest statistics confirm that improving energy security requires both expanding domestic renewable generation and strengthening system flexibility. The analysis evaluates electricity demand on a supplied-energy basis incorporating a 12% loss objective. It uses the approximately 16.9% capacity factor observed for the 2023 wind fleet as the conservative central assumption for onshore wind, with 25% and 32% examined as sensitivity cases.

Under the reference growth case, end-use demand reaches approximately 25.83 TWh in 2040 and requires approximately 29.35 TWh of supplied electricity. With the stated assumptions, S0, S1, and S2 provide approximately 28.4%, 60.0%, and 80.1% of reference supplied electricity from renewable resources after the common 8% integration allowance. S1 increases to approximately 65.5% at a 25% onshore-wind capacity factor and 70.3% at 32%, showing that wind performance is a material planning uncertainty.

Capacity adequacy is more restrictive than annual energy balance. Under conservative duration and capacity-credit assumptions, S1 provides approximately 7.41 GW of evening firm capacity compared with 7.46 GW in the reference-growth case and 8.65 GW in the high-growth case. The balanced pathway therefore requires additional dependable flexibility before a positive planning reserve margin can be demonstrated. Longer-duration storage, greater demand response, additional efficient firm capacity, or contracted interconnection support are possible alternatives.

The principal conclusion is therefore not that one fixed 2040 configuration has already been proven technically and economically optimal. Rather, a coordinated portfolio of solar PV, diversified wind, storage, demand response, flexible generation, loss reduction, and regional interconnection can materially reduce Tunisia's external energy dependence, but final planning decisions require chronological dispatch, probabilistic adequacy, network-constrained analysis, and lifecycle economic optimization.

DECLARATIONS

Conflict of interest: The author(s) declare no known competing financial interests or personal relationships that could have influenced the work reported in this paper.

Data availability: The study uses publicly available STEG, ONEM, IRENA, World Bank, and peer-reviewed sources cited in the reference list. Scenario calculations are reproducible from the assumptions reported in the manuscript.

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CONFLICTS OF INTEREST

All authors declare no conflict of interest.

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