May 2026

SUMMER OUTLOOK 2026

SEASONAL ADEQUACY ASSESSMENT

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Abbreviations

CCGT	–	Combined Cycle Gas Turbine
EU	–	European Union
ENS	–	Energy Not Served
EENS		Expected Energy Not Served
FCR	–	Frequency Containment Reserve
FRR	–	Frequency Restoration Reserve
NGIC		Net Generation Installed Capacity
NTC	–	Net Transfer Capacity
OCGT	–	Open Cycle Gas Turbine
O&M	–	Operating and Maintenance
PEMMDB	–	Pan-European Market Modelling Database (developed by ENTSO-E)
PECD	–	Pan-European Climate Database
RES	–	Renewable Energy Sources that generally include wind, solar and hydro capacities. In this study, RES refers only to wind and solar as VRES (Variable RES) capacities.
ROR	–	Run-of-River
TPP		Thermal Power Plant
TSO	–	Transmission System Operator
TYNDP	–	Ten-year Network Development Plan (Europe's Network Development Plan prepared bi-annually by ENTSO-E)
MCY		Monte Carlo Climatic Year
CY		Climatic Year

Market areas/countries:

Med-TSO	–	Association of the Mediterranean Transmission System Operators (TSOs) for electricity
DZ	–	Algeria
EG	–	Egypt
IL	–	Israel
JO	–	Jordan
LY	–	Libya
MA	–	Morocco
PS	–	Palestine
TN	–	Tunisia
LB	–	Lebanon
ES	–	Spain

1. Executive Summary

This report presents the projected adequacy situation among non-EU Med-TSO members for the summer of 2026. With this assessment, Med-TSO aligns with global best practices and with the latest developments in EU regulation.[1] These investigations evaluate the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria. This approach is necessary due to the stochastic nature of renewable energy systems (RES) and their intermittency, and due to power system operation, which is increasingly based on open market conditions; all these aspects call for the assessment of power system adequacy in the short-, mid- and long-term. Moreover, the integration of substantial quantities of RES must be closely followed by the commissioning of devices that can provide adequate power system flexibility.

This Summer Outlook 2026 Report provides important information about potential adequacy issues during the period from 25 May through to 4 October 2026 in six MED-TSO countries: Morocco, Tunisia, Libya, Egypt, Jordan, and Lebanon.

Data for Algeria are missing from this assessment due to limited engagement from Algeria. Data for Israel and Palestine are not available at the present time. The main adequacy indicators assessed are as follows:

- **Loss of Load Duration (LOLD)** in a given geographical zone for a given period is the number of hours during which the zone experiences ENS during a single Monte Carlo sample/simulation year.
- **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected (average) number of hours per year when there is a lack of resources to cover the demand needs, within a sufficient transmission grid operational security limit.
- **Expected Energy Not Served (EENS)** in a given geographical zone for a given period, is the (average) value of energy anticipated not to be supplied due to lack of resources while complying with transmission grid operational security limits.
- **Relative EENS:** is a more suitable indicator to compare adequacy across geographical scope as it represents the percentage of annual demand expected not to be supplied.

The adequacy situation is assessed using a two-step approach. In the first step, adequacy under isolated system operation is evaluated. In the second, adequacy under interconnected system operation is determined to quantify the

[1] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en

importance of interconnections. For the interconnected mode, we identify the exchange needed to overcome the adequacy situation.

A key advancement in this report is the adoption of the new PECD 4.2 in Med-TSO studies, which provides a more probabilistic and realistic view of adequacy risks compared to earlier studies.

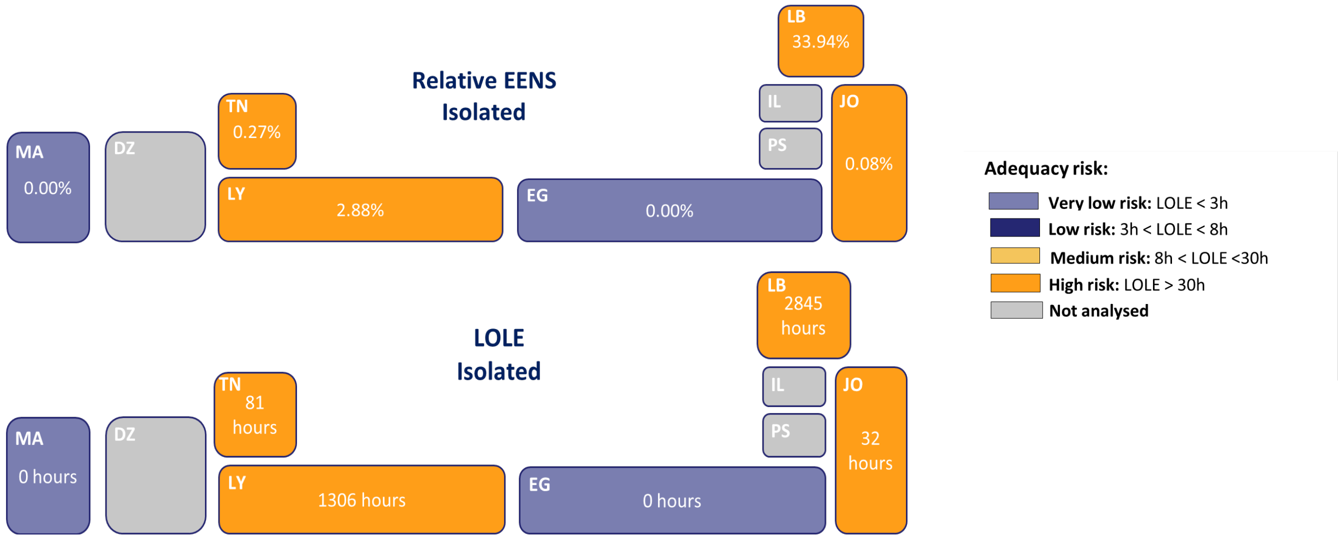


Figure 1 Relative EENS and LOLE for isolated system under normal operation mode (SO 2026).

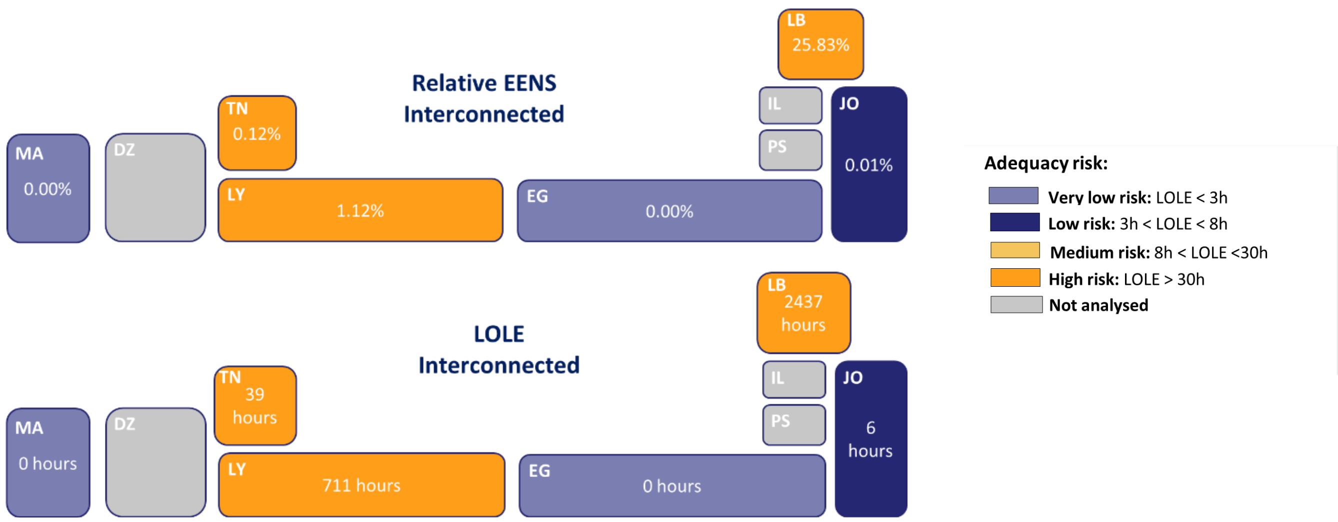


Figure 2 Relative EENS and LOLE for interconnected system under normal operation mode (SO 2026).

Conclusion

The adequacy assessment of the regional power system for SO 2026 highlights the significant impact of interconnection on system reliability, particularly in reducing loss-of-load risk (LOLE) and expected relative energy not served (EENS).

In the isolated mode

Figure 1, several countries face notable adequacy challenges:

- **Lebanon (LB)** presents the most critical situation in the region, with extreme LOLE and relative EENS values that indicate near-persistent supply shortages in the absence of cross-border support. Without interconnection, Lebanon's domestic generation capacity is fundamentally insufficient to meet projected demand.
- **Libya (LY)** also faces considerable adequacy stress, reflecting significant limitations in domestic generation capacity. The scale of its supply deficit under isolation underscores a structural vulnerability that cannot be resolved through operational measures alone.
- **Tunisia (TN)** exhibits moderate adequacy risk, with periodic but manageable supply constraints that suggest capacity margins are tight yet not critically deficient.
- **Jordan (JO)** records comparatively low adequacy risk, with only marginal exposure to supply shortfalls under isolated conditions.
- **Morocco (MA)** and **Egypt (EG)** demonstrate negligible adequacy risk, confirming that their domestic generation portfolios are sufficient to meet projected demand without external support.

In the interconnected mode

Figure 2, the situation improves substantially:

- **Lebanon (LB)** remains the most constrained country in the region. While interconnection delivers meaningful relief by reducing the frequency and severity of supply shortfalls, the improvement alone is insufficient to resolve Lebanon's underlying adequacy deficit. This points to the urgent need for targeted domestic capacity investment alongside regional integration efforts.
- **Libya (LY)** benefits most significantly from interconnection, with a substantial reduction in both LOLE and relative EENS. This marked improvement highlights Libya's strong dependence on cross-border exchanges to

achieve acceptable reliability levels and raises important questions about the resilience of its supply in the event of interconnection disruptions.

- **Tunisia (TN)** improves notably under interconnected conditions, with effective support from neighbouring systems bringing its adequacy risk to a low level.
- **Jordan (JO)** achieves a high level of reliability under interconnection, transitioning from low to very low adequacy risk and demonstrating the country's ability to leverage regional exchanges effectively.
- **Morocco (MA),** and **Egypt (EG)** maintain full adequacy under both scenarios, confirming the robustness of their domestic generation portfolios and their potential role as net exporters within the regional framework.

Challenges in Libya

Despite the improvements noted in the previous release, the situation in Libya has deteriorated again due to renewed political instability and operational constraints. The system continues to face long-standing structural and technical difficulties that limit its reliability and resilience.

- Aging infrastructure and limited transmission capacity continue to hinder the full utilization of interconnection benefits.
- The dependency on imports from neighbouring systems remains essential to sustain adequacy during peak or stressful conditions.

Ensuring lasting improvement requires rehabilitation of the domestic grid, reinforcement of interconnections, and stabilization of fuel and gas supplies through better coordination between the power and gas sectors.

The earlier assessment assumed stable political and operational conditions, but recent developments have shown that such stability cannot be guaranteed, reversing some of the previous gains.

Challenges in Lebanon

The adequacy situation in Lebanon remains highly critical, although interconnection scenarios indicate the potential for partial improvement. Even under the hypothesis of full interconnection and full generation availability, the overall risk would remain elevated.

- High LOLE values persist due to insufficient generation capacity in the power system.
- Fuel and gas shortages, alongside frequent outages, and aging assets, continue to constrain operational reliability.
- Grid limitations and restricted import capacity reduce the extent to which interconnections can mitigate supply deficits.

Significant enhancement of domestic generation, fuel availability, and cross-border transmission capacity would be required to achieve a sustainable adequacy improvement.

While interconnection could alleviate part of the adequacy risk, it alone cannot fully resolve Lebanon's structural energy challenges without addressing the underlying supply and fuel issues.

2. What's New in This Release

Regional Statement on Energy Conservation Measures in Preparation for Summer 2026

In response to regional energy supply pressures arising from the ongoing conflict in the Middle East, the following countries have announced a series of emergency measures aimed at reducing fuel consumption and managing electricity demand ahead of the summer peak season.

EGYPT	Egypt has implemented a national energy conservation programme including reductions in public lighting, shortened operating hours for commercial establishments and shopping centres, and restrictions on air conditioning temperatures in government buildings. The Ministry of Electricity has also urged citizens and businesses to reduce consumption during peak hours, while accelerating the commissioning of delayed generation units ahead of summer.
MOROCCO	Though relatively insulated from the immediate supply shock, Morocco has reinforced its demand management framework by tightening energy efficiency requirements in public buildings and launching a public awareness campaign on responsible electricity use, in particular the use of air conditioners.
TUNISIA	Tunisia facing one of its most constrained summers in recent years, Tunisia has introduced rolling demand reduction measures including restrictions on commercial lighting and air conditioning, extended off-peak tariff incentives to shift consumption away from peak hours, and appeals to industrial consumers to voluntarily curtail during critical periods. Negotiations with Algeria to temporarily increase import flows are also reportedly under discussion, subject to technical constraints.
LIBYA	Libya has introduced emergency fuel management measures for power generation due to ongoing fuel supply shortages affecting the electricity sector. The primary challenge is the insufficient availability of fuel rather than the efficiency of generating units. Power plants capable of operating are dispatched whenever adequate fuel is available. To help manage the situation and reduce pressure on the power system, the government has appealed to citizens to limit air conditioning use during peak afternoon hours as the country prepares for another challenging summer.

LEBANON

Lebanon, already operating under a chronic electricity crisis, has taken steps to extend the operating hours of the state utility Électricité du Liban where fuel supply permits, while simultaneously encouraging — and in some areas mandating — the expansion of rooftop solar installations to reduce dependence on the grid and private diesel generators. Fuel procurement efforts have been intensified through emergency bilateral agreements with regional partners.

JORDAN

Jordan has activated its national demand response programme ahead of schedule, introducing incentive-based load shifting for large industrial and commercial consumers, reducing public lighting loads, and tightening temperature controls in government facilities. Jordan is also coordinating closely with Egypt to ensure full utilisation of available interconnection capacity throughout the summer peak period.

PECD 4.2

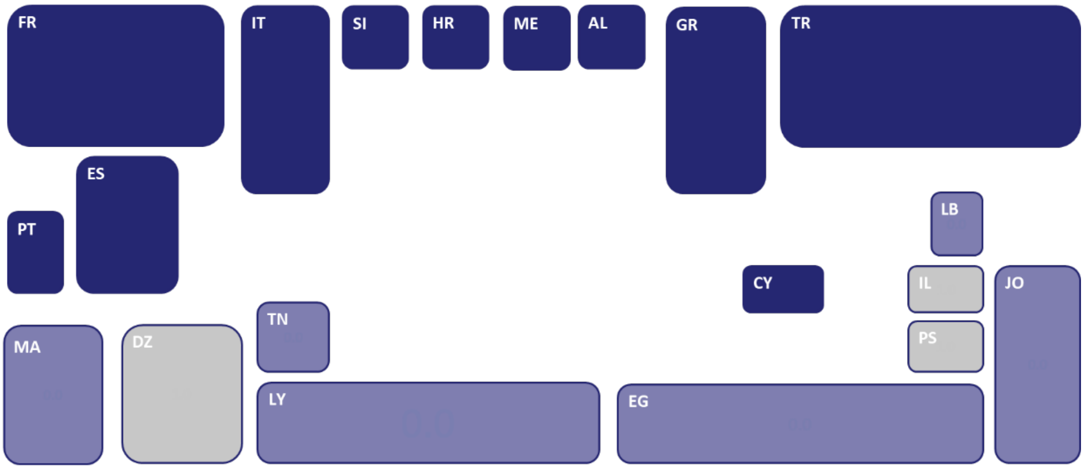
In previous editions of our adequacy assessment, we relied on PECD 3.5, which was based on adjusted historical weather and climate data. While useful, this approach was limited in its ability to capture renewable energy behaviour under evolving climate conditions, as the coverage of future climate projections was restricted.

Thanks to the cooperation agreement between Med-TSO and ENTSO-E, we gained early access to the newly released PECD v4.2 (2025). This updated dataset includes both long-term historical records (from 1950 onwards) and forward-looking climate projections based on four Shared Socioeconomic Pathways (SSPs) and six CMIP6 climate models, covering the period 2015–2100. Developed by the Copernicus Climate Change Service (C3S), PECD v4.2 provides scientifically robust futures rather than relying solely on past data.

By integrating PECD v4.2, the Summer Outlook 2026 can now simulate electricity demand, renewable output, and cross-border flows with hourly resolution across multiple climate scenarios. This offers a much clearer picture of how extreme weather events, seasonal variability, and long-term climate shifts could impact adequacy risks. Overall, it represents a major methodological step forward and significantly strengthens the robustness of our assessment.

3. Overview of the MED-TSO Power Systems in Summer 2026

This Summer Outlook 2026 Report provides information regarding potential adequacy issues in six MED-TSO member states: Morocco, Libya, Tunisia, Egypt, Jordan, and Lebanon.



Med-TSO members analysed in this adequacy assessment
Med-TSO members not analysed in this adequacy assessment
Med-TSO members participating in the ENTSO-E adequacy study

Figure 3 Med-TSO members and neighbouring countries (source: Med-TSO).

- *Data for Algeria is missing from this assessment due to limited engagement from the Algerian side. Data for Israel and Palestine is currently unavailable*.

The analysed period includes all hours between the beginning of week 22 and the end of week 40, 2026, which constitutes the period between Monday 25 May and Sunday, 4 October. The overview is organised in alphabetical order, including submitted data, assumptions and proxies used to develop the corresponding market model using the Antares software tool.

All relevant parameters are presented so that the reader can verify their credibility and confirm their usability for adequacy analyses.

A. Demand evolution

Table 1 presents the expected consumption per week from week 22 through to week 40, in 2026. These values constitute the average weekly consumption for 36 climatic years in the period from PECD 4.2.

The following table highlights the highest and lowest values for each country during the summer period.

Table 1 Expected consumption in the summer weeks – 2026.

Weekly consumption based on average among 36 CY (GWh)		EG	JO	LB	LY	MA	TN
Total		111564	10530	8447	23907	20528	10152
Week	22	5314	531	395	1063	973	436
Week	23	5602	533	406	1124	1047	461
Week	24	5714	539	418	1167	1044	479
Week	25	5911	569	435	1191	1073	522
Week	26	5944	570	442	1247	1094	541
Week	27	5965	569	450	1324	1104	550
Week	28	6034	576	462	1339	1118	566
Week	29	6158	597	476	1353	1133	588
Week	30	6139	588	473	1365	1138	594
Week	31	6255	603	485	1390	1121	619
Week	32	6245	593	479	1380	1129	607
Week	33	6177	578	472	1367	1120	582
Week	34	6080	565	471	1342	1070	563
Week	35	5961	552	458	1326	1076	567
Week	36	5921	543	445	1285	1092	546
Week	37	5759	526	436	1247	1070	519
Week	38	5587	507	423	1178	1059	487
Week	39	5448	496	415	1135	1035	467
Week	40	5349	493	405	1085	1030	458

High Value
Low Value

The table shows that Egypt's consumption is significantly higher than that of other countries. To better illustrate this, it is plotted using a separate y-axis on the right side of the graph below.

Weekly consumption in Jordan, Lebanon, and Tunisia is the lowest among the six analysed countries. The highest is in Egypt, where it is almost 10 times higher, comparatively. Consumption in Libya and Morocco falls in between, although we can still observe significant differences between them.

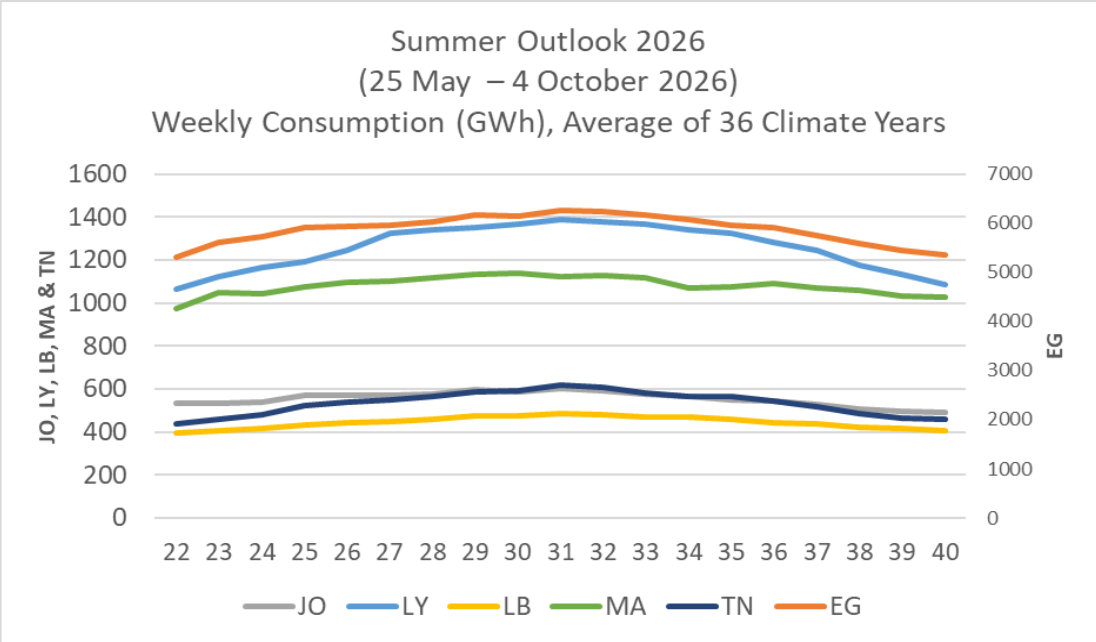


Figure 4 Expected weekly consumption per country in the analysed season.

The following table and figures present the hourly peak demand values, showing the 95 percentile (P95) maximum weekly peak loads across all 36 climatic years.

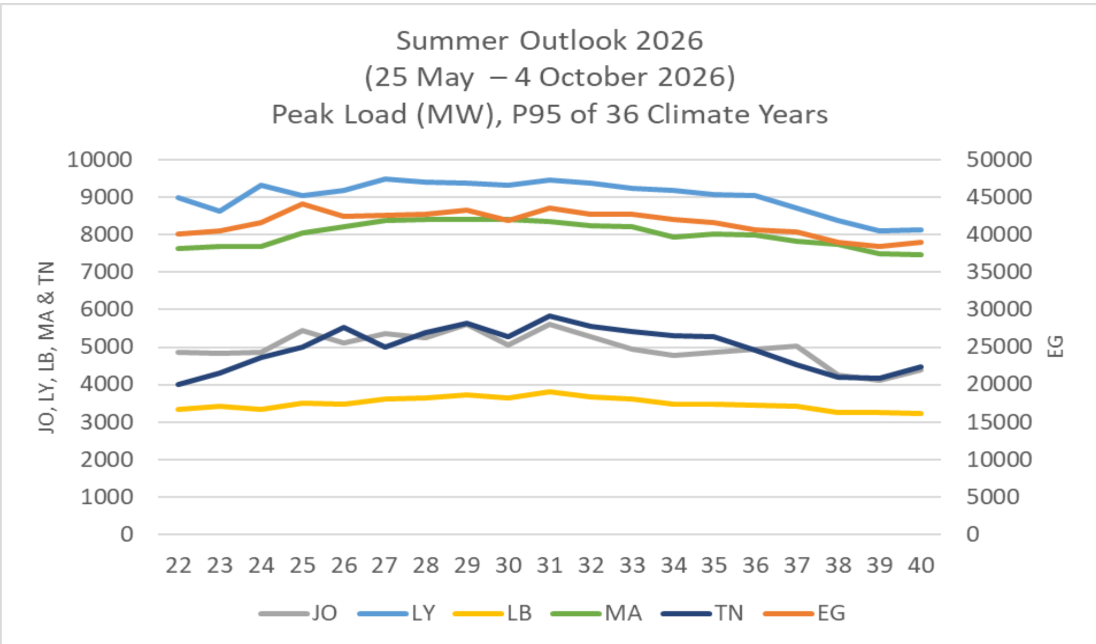


Figure 5 Maximum weekly peak loads per country in the analysed season.

Table 2 Maximum weekly peak loads in summer weeks 2026.

Peak load, based on P95 among 36 CY (MW)		EG	JO	LB	LY	MA	TN
Maximum		44066	5624	3800	9480	8418	5827
Week	22	40122.75	4854.5	3327.5	8995	7648	4001.75
Week	23	40467.5	4825.5	3424.25	8625.75	7690	4296.5
Week	24	41674.25	4858.25	3331	9323.75	7700	4723.5
Week	25	44066.25	5444.25	3518.25	9044.75	8063	5000
Week	26	42428.75	5123.25	3488	9175.75	8211	5524.25
Week	27	42655.75	5349	3609.75	9480	8373	5002.5
Week	28	42808.75	5255.75	3647.75	9403.5	8397	5388.5
Week	29	43316.25	5624.25	3716.5	9385.25	8416	5646
Week	30	41938.25	5071.25	3655	9324.5	8418	5279.75
Week	31	43571.75	5615.75	3799.75	9467	8349	5827
Week	32	42744.25	5293	3659.25	9388.25	8254	5567.5
Week	33	42780.25	4949.5	3625.5	9252.5	8226	5423.75
Week	34	42074.25	4771.75	3492	9197.75	7953	5320.75
Week	35	41688.75	4876	3476.5	9071	8012	5281.75
Week	36	40607	4938	3453.75	9045.25	8007	4923.75
Week	37	40379.75	5036	3411	8720.25	7829	4539.75
Week	38	38973.75	4261	3256.5	8387.5	7752	4187.25
Week	39	38482.75	4115	3245.5	8104.5	7509	4169.75
Week	40	39059	4396.5	3219.75	8120	7460	4483.5

High Value
Low Value

It’s worth mentioning that In Jordan, the peak load is observed during winter as well as summer.

B. Expected evolution of installed capacities

The following tables present the expected available installed capacities during the summer period of 2026. Total installed capacity in the observed region is expected to reach 101 GW, with nearly 78 GW (approximately 77%) coming from thermal units.

Compared to SO 2025, changes in installed capacities are highlighted using two colours: green for increases and orange for decreases.

The battery storage is increasing in the region. Egypt[2] has deployed 1220 MWh battery storage with a two-hour discharge (610 MW per hour), while in Morocco[3], 250 MWh of battery storage is expected to be in service by the end of 2026.

The battery discharge depends on the need of the system or during peak demand.

Another key observation is the rapid expansion of renewable installed capacities across almost all countries. However, Lebanon stands out as an exception, as the current regional situation has severely impacted solar rooftop systems.

Table 3 Total expected available installed capacities (MW) per technology during summer period from Week 22 to Week 40, 2026.

Med-TSO Member	Expected WPP capacity		Expected solar PV capacity		Expected CSP capacity (with storage)		Expected CSP capacity (without storage)		Expected HPP capacity		Expected battery storage capacity		Expected hydro pump storage capacity		Expected TPP capacity		TOTAL [MW]
	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	
EG	3036.37 (No Change)	5%	4441 (42%▲)	7%	-	-	140 (No Change)	0%	2974 (5%▲)	5%	610 (51%▲)	1%	-	-	50017 (-1%▼)	82%	61218
JO	621 (No Change)	8%	2332 (6%▲)	30%	-	-	-	-	-	-	-	-	-	-	4785 (No Change)	62%	7738
LB	-	-	1470 (13%▲)	37%	-	-	-	-	285 (No Change)	7%	-	-	-	-	2167 (-15%▼)	55%	3922
LY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9002 (-14%▼)	100%	9002
MA	2560 (6%▲)	20%	688.5 (11%▲)	5%	540 (No Change)	4%	-	-	1306 (No Change)	10%	-	-	790 (No Change)	6%	6940 (8%▲)	54%	12825
TN	229 (0%▼)	4%	800 (82%▲)	13%	-	-	-	-	-	-	-	-	-	-	5117 (-1%▼)	83%	6146
TOTAL	6446	6%	9732	10%	540	1%	140	0%	4565	5%	610	1%	790	1%	78028	77%	100851

	Available Installed Capacity [GW]	Peak Load [GW]
EG	61.2	44
JO	7.7	5.6
LB	3.9	3.8
LY	9	9.5
MA	12.8	8.4
TN	6.1	5.8

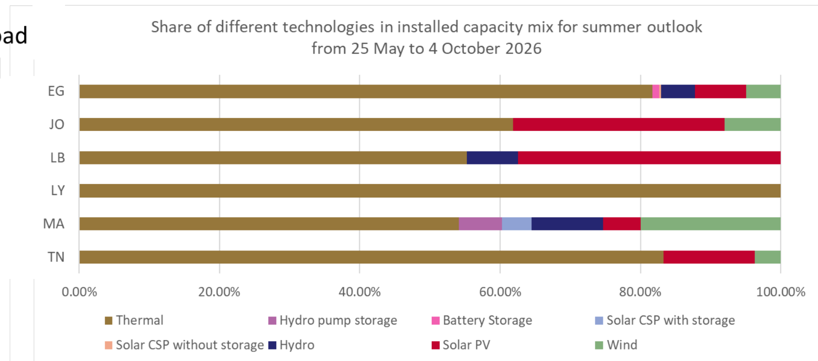


Figure 6 Available Installed capacity mix and peak load in summer period.

It's important to highlight that Libya's power system relies exclusively on thermal power plants. In contrast to prior adequacy assessments, its thermal fleet has undergone a thorough re-evaluation. This reassessment considers the

[2] For Egypt (EETC), battery storage is expected to be commissioned during April and July 2026.
[3] For Morocco (ONEE), a battery storage tender has been launched and is expected to be operational between Q3/Q4 2026.

maintenance activities performed by the Libyan system, which has led to the restoration of certain power plants that were previously offline. Additionally, some power plants have been excluded due to severe damage, while newly introduced power plants have also been incorporated into the evaluation. This comprehensive approach ensures a more accurate reflection of the current state of Libya's thermal generation capacity.

Relevant hydroelectric capacities are present only in Egypt and Morocco. In Egypt, capacity improvements are being implemented through turbine enhancements aimed at increasing overall output, resulting in an assumed 5% increase. Morocco currently operates a pumped storage hydropower plant (PSHPP) with a total capacity of 790 MW.

The highest participation of wind and solar in total generation capacities is found in Lebanon, Jordan, and Morocco, reaching more than 38% of the installed capacity. It should be noted that in Morocco, 540 MW of solar capacity is in solar thermal farms with storage.

Capacity factors related to wind and solar generation are presented in Table 4. It is worth mentioning that capacity factors consider the technology used and the zone splitting of each country according to PECD v4.2.

Table 4 Wind and solar capacity factors for all countries during SO 2026.

	2026		
Country	**Wind CF**	**Solar CF**	**Solar CSP**
EG	54.4%	26.2%	24.4%
JO	34%	26.5%	-
LB	-	18%	-
LY	-	21.7%	-
MA	59. 3%	19.6%	31.2%
TN	16%	18.2%	-

The impact of RES generation in Egypt and Tunisia is marginal since the participation of thermal units is above 80%. Among thermal technologies, the majority is gas-fired units. Regarding thermal units, available capacities consider the forced outages rate according to data provided, as well as derating factors, which define the reduction in available thermal capacities for various reasons.

Planned outages are modelled according to data provided by TSOs (TN & MA) or as random planned outages, while respecting certain predefined rules as shown in the table below.

Table 5 shows the months when maintenance is allowed and when it is not.

Market Node	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
EG00	yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes
JO00	no	no	yes	yes	yes	yes	no	no	no	yes	yes	no
LB00	no	no	yes	yes	yes	no	no	no	no	yes	yes	no
LY00	no	yes	yes	yes	yes	no	no	no	yes	yes	yes	no

- In Egypt and Lebanon, planned outages are not envisaged in the period from 1 June to 30 September.
- In Jordan, planned outages are not envisaged in the period from 1 July to 30 September.
- In Libya, planned outages are not envisaged in the period from 1 June to 31 August.
- In Morocco, and Tunisia, detailed planned outages are provided and considered during the simulations.

Forced outages of thermal units are modelled as random events in all cases and across all countries, based on predefined parameters. Similarly, for thermal units, commissioning/decommissioning dates are considered.

C. Interconnections between countries

Summarised NTC values are used as available cross-border capacities, and we assume that these capacities are only used if a country is facing adequacy issues for the entire calculation period. The Net Transfer Capacity (NTC) represents the maximum exchange capacity between two nodes compatible with security standards applicable in both nodes, most notably the N-1 criterion, which requires that the network remains stable following the sudden loss of any single network element. In practice, a country may choose to exceed the NTC on a given corridor — accepting a temporary reduction in security margin — to meet urgent demand.

The Antares model included the power systems of six analysed Med-TSO member countries with detailed generation capacities and demand, and a simplified representation of the transmission network and cross-border capacities, represented as NTC values. The internal transmission network has not been modelled in the market simulator. Furthermore, in the case of borders with countries outside of the Med-TSO region, exchanges have been modelled using hourly data provided by our members. In the case of Algeria, it is assumed that the country can export electricity to neighbouring countries in the event of adequacy risk, and that Algeria itself does not face any adequacy risk.

A particular structural constraint worth highlighting is the Egypt–Jordan (EG–JO) interconnection, which consists of a single circuit only. Unlike corridors served by multiple parallel circuits where the loss of one still leaves residual transfer capacity, the EG–JO link offers no redundancy: a trip on this circuit would result in a complete interruption of cross-border exchange between the two countries simultaneously. This makes it inherently impossible to satisfy the N-1 criterion on this corridor, and any adequacy scenario relying on EG–JO exchange should be interpreted with this limitation in mind.

For Lebanon, we evaluated a hypothetical interconnection between Lebanon and Jordan through Syria, which would enable Lebanon to potentially import up to 250 MW of electricity as a sensitivity measure. A summary of the interconnection capacities and given exchanges is presented in the following Figure 7 followed by Table 6 to explain the node definition during the modelling.

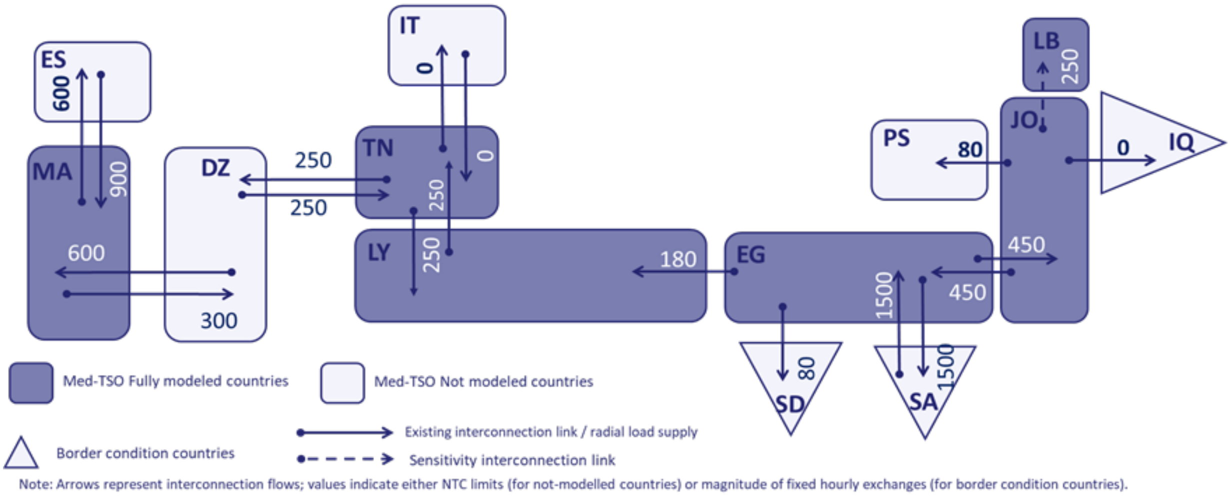


Figure 7 Net transfer capacity during SO 2026.

Table 6 Definition of node categories and modelling resolutions

Category	Modelling Detail	Functional Role in Simulation
Med-TSO *fully modelled countries*	Explicit representation of hourly demand, RES profiles, and thermal units.	Primary focus for adequacy (*ENS*, *LOLE*) and flexibility metrics.
Med-TSO *not-modelled countries*	Simplified nodes characterized solely by Net Transfer Capacity (NTC) limits only.	Act as aggregated external market nodes, enabling bidirectional exchanges and typically providing emergency imports when modelled zones cannot meet demand.
Border condition countries	Pre-defined, hourly exchange profiles (exogenous and non-responsive to system conditions).	Represents flows from synchronous or non-synchronous external areas. these profiles remain static across all Monte Carlo samples, ensuring that results reflect internal system sensitivities rather than fluctuating external support.

D. Reserve requirements and modelling.

Reserve requirements have been provided for each country (Table 7). In some countries (MA), the percentages of capacity reduction at thermal units due to the provision of FCR have been provided and these percentages have been applied in the Antares modelling. No additional FCR requirements have been modelled. In countries in which these percentages are not known, FCR has been modelled as a negative balance (Export) with the rest of world (ROW) node in our simulation tool. FRR requirements have been modelled as a negative balance (Export) with the rest of world (ROW) node in our simulation tool, in all countries.

Table 7 Balancing reserve requirements.

Reserve		SO 2026
EG	FCR+FRR [MW]	1200
JO	FCR+FRR [MW]	200
LB	FCR+FRR [MW]	120
LY	FCR+FRR [MW]	250
MA	FCR+FRR [MW] [4]	700
TN	FCR+FRR [MW]	220

[4] FCR for MA has been modelled through reduced thermal capacity by a total of 347 MW.

4. Adequacy Situation Overview

4.1. Adequacy assessment

The adequacy situation has been assessed using a two-step approach. In the first, adequacy under isolated system operation is evaluated. In the second, adequacy under interconnected system operation is assessed to quantify the importance of interconnections.

In a theoretical isolated scenario Figure 8, which focuses on the summer season, adequacy high risks are identified in Jordan, Tunisia, Libya and Lebanon.

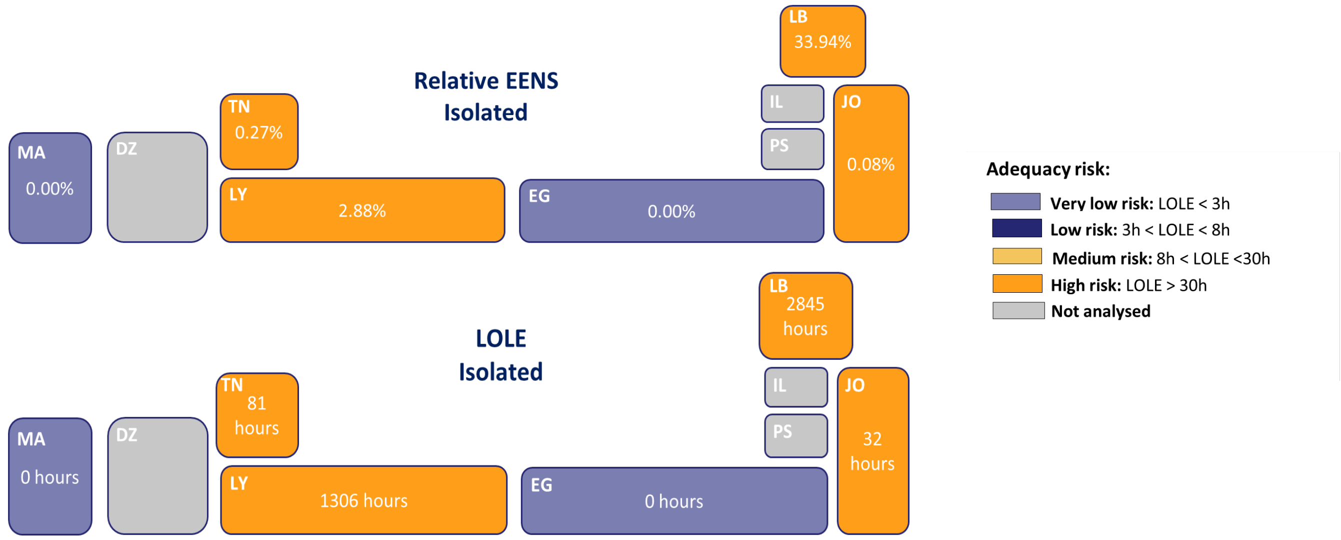


Figure 8 Relative EENS and LOLE for isolated system under normal operation mode (SO 2026).

Interconnections and energy exchanges needed to overcome adequacy issues with neighbouring countries reduce adequacy risks to low in the case of Jordan but in Tunisia, Libya and Lebanon, even in this more relaxed operating mode, adequacy risks are at an unacceptable level.

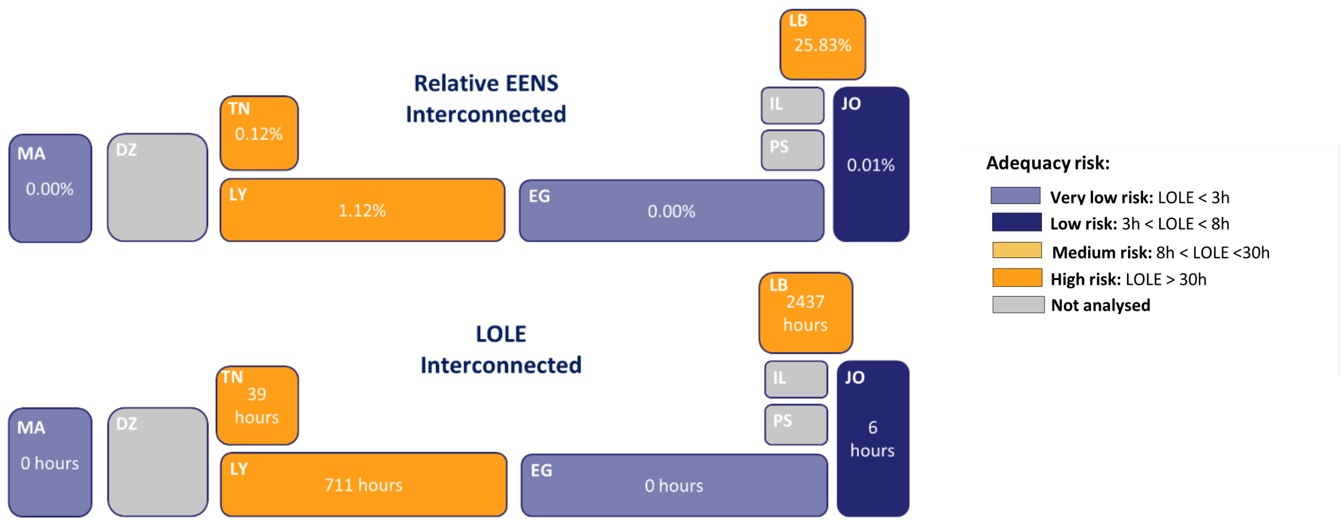


Figure 9 Relative EENS and LOLE for Interconnected system under normal operation mode (SO 2026).

Table 8 Seasonal EENS for interconnected and isolated scenarios.

Country	Isolated EENS	Interconnected EENS	Isolated LOLE	Interconnected LOLE
EG	43 MWh	15 MWh	0.04 h	0.02 h
	50th percentile 0 MWh	50th percentile 0 MWh	50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh	95th percentile LOLD: 0 hours	95th percentile LOLD: 0 hours
JO	8155 MWh	1148 MWh	32.03 h	5.59 h
	50th percentile 5119 MWh	50th percentile 105 MWh	50th percentile LOLD: 25 hours	50th percentile LOLD: 2 hours
	95th percentile 27683 MWh	95th percentile 5783 MWh	95th percentile LOLD: 93 hours	95th percentile LOLD: 22 hours
MA	11 MWh	0 MWh	0.02 h	0 h
	50th percentile 0 MWh	50th percentile 0 MWh	50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh	95th percentile LOLD: 0 hours	95th percentile LOLD: 0 hours
TN	27786 MWh	12572 MWh	80.84 h	38.88 h
	50th percentile 17726 MWh	50th percentile 6711 MWh	50th percentile LOLD: 62 hours	50th percentile LOLD: 28 hours
	95th percentile 82028 MWh	95th percentile 37423 MWh	95th percentile LOLD: 219 hours	95th percentile LOLD: 122 hours
LY	687849 MWh	266815 MWh	1305.81 h	710.97 h
	50th percentile 669393 MWh	50th percentile 246421 MWh	50th percentile LOLD: 1309 hours	50th percentile LOLD: 694 hours
	95th percentile 1036402 MWh	95th percentile 472109 MWh	95th percentile LOLD: 1665 hours	95th percentile LOLD: 1085 hours
LB	2867042 MWh	2182303 MWh	2845.49 h	2437.09 h
	50th percentile 2885802 MWh	50th percentile 2198645 MWh	50th percentile LOLD: 2859 hours	50th percentile LOLD: 2448 hours
	95th percentile 3174435 MWh	95th percentile 2486361 MWh	95th percentile LOLD: 3046 hours	95th percentile LOLD: 2733 hours

Adequacy risk:
- **Verv low risk:** LOLE < 3h
- **Low risk:** 3h < LOLE < 8h
- **Medium risk:** 8h < LOLE < 30h
- **High risk:** LOLE > 30h

Table 8 provides detailed seasonal EENS and LOLD results for all analysed countries, including P50 and P95 sensitivity scenarios. Results point to adequacy issues in some countries, notably the following:

Jordan

Under normal conditions, Jordan faces a moderate adequacy risk in isolated mode, with LOLE lasting approximately 32 hours and EENS reaching 8,155 MWh. While the frequency of supply shortfalls is notable, the relatively contained volume of unserved energy suggests that the deficit, though present, remains manageable in magnitude. In interconnected mode, both dimensions improve significantly — LOLE falls to approximately 6 hours and EENS to 1,148 MWh — demonstrating that regional exchanges are highly effective in resolving Jordan's supply gaps.

Under the P95 sensitivity scenario, LOLE in isolated mode can reach 93 hours with EENS surging to 27,683 MWh, indicating that Jordan's generation margins are vulnerable under adverse conditions. In interconnected mode, the impact remains considerably lower, with LOLE limited to 22 hours and EENS to 5,783 MWh, confirming that interconnection provides strong and consistent protection even under extreme stress. *These findings highlight the crucial role of interconnections in enhancing Jordan's adequacy under extreme conditions.*

Tunisia

Under normal conditions, Tunisia faces a high adequacy risk in isolated mode, with LOLE lasting approximately 81 hours and EENS reaching 27,786 MWh. This combination indicates that supply shortfalls occur with notable frequency and carry a substantial volume of unserved energy, pointing to a meaningful structural gap in domestic generation capacity. In interconnected mode, both dimensions of risk are reduced — LOLE falls to approximately 39 hours and EENS to 12,572 MWh — demonstrating that regional exchanges effectively reduce both the frequency and the magnitude of supply shortfalls.

Under the P95 sensitivity scenario, which reflects more severe but less probable conditions, LOLE in isolated mode can reach 219 hours with EENS surging to 82,028 MWh, confirming that Tunisia's generation margins are highly sensitive to adverse conditions. In interconnected mode, the impact is considerably lower, with LOLE limited to 122 hours and EENS to 37,423 MWh, though the risk level remains elevated even with regional support under extreme conditions. *These findings emphasise the vital role of interconnections in mitigating Tunisia's adequacy risks under extreme conditions.*

Libya

Under normal conditions, Libya faces a high adequacy risk in isolated mode, with LOLE lasting approximately 1,306 hours and EENS reaching 687,849 MWh (≈688 GWh). The combination of very high LOLE and very high

EENS reveals that Libya's system is not only failing for a significant portion of the year, but that the volume of unserved energy during those failures is substantial, reflecting a deep structural generation deficit.

In interconnected mode, a meaningful improvement is observed, with LOLE reducing to approximately 711 hours and EENS to 266,815 MWh (≈267 GWh). While this reduction confirms that regional exchanges provide valuable support, the risk level remains high, indicating that Libya's adequacy challenge cannot be fully resolved through interconnection alone.

Under the P95 sensitivity scenario, the situation deteriorates considerably. In isolated mode, LOLE can extend to 1,665 hours with EENS reaching 1,036,402 MWh (≈1 TWh). Even in interconnected mode under P95 conditions, LOLE reaches 1,085 hours and EENS 472,109 MWh, underscoring Libya's heavy structural dependence on cross-border support and the urgent need for domestic generation investment.

Lebanon

Lebanon presents the most severe adequacy situation in the region, with LOLE of 2,845 hours in isolated mode — equivalent to approximately 32% of the entire year — and EENS of 2,867,042 MWh (≈2.9 TWh). This combination of very high LOLE and very high EENS is the most critical outcome possible: the system is not only failing frequently, but the volume of unserved energy during those failures is enormous, reflecting deep and sustained supply deficits throughout the season.

In interconnected mode, some relief is observed, with LOLE reducing to 2,437 hours and EENS to 2,182,303 MWh. However, the scale of improvement is limited relative to the magnitude of the deficit, confirming that regional interconnection alone is insufficient to resolve Lebanon's adequacy crisis.

Under the P95 sensitivity scenario, the situation deteriorates further. In isolated mode, LOLE can extend to 3,046 hours — over 34% of the year — with EENS reaching 3,174,435 MWh (≈3.2 TWh). Even in interconnected mode under P95 conditions, LOLE reaches 2,733 hours and EENS 2,486,361 MWh, underscoring the structural and chronic nature of Lebanon's supply deficit that cannot be addressed through operational measures or regional integration alone.

Egypt and Morocco

Both Egypt and Morocco demonstrate negligible adequacy risk under all assessed scenarios. LOLE and EENS values remain at or near zero across both isolated and interconnected modes, as well as under P50 and P95 sensitivity conditions. The near-zero EENS confirms not only that supply shortfalls are virtually non-existent, but that when marginal stress does occur, the volume of unserved energy is inconsequential. This confirms the robustness of their domestic generation portfolios and their capacity to serve as reliable anchors within the regional system. It should be noted that curtailment of RES generation can only happen in Jordan and

Morocco in isolated operations, but that this curtailment is marginal, far below 1% of RES generation. The rationales behind these results are explained in the relevant country chapters.

4.2. Importance of interconnections

In this chapter, we thoroughly explore the interconnections between the countries under analysis and their need for energy exchange to mitigate anticipated adequacy challenges in the coming summer. Our primary objective is to evaluate potential cross-border exchanges among the six analysed countries and quantify each one's requirements to address adequacy risks during periods of isolation. The following table summarises the feasible exchanges needed to overcome adequacy risks and NTC among the countries subject to our analysis.

Table 9 Exchanges needed to overcome adequacy risks in the region.

Link		Country A – Country B Exchanges for Adequacy (GWh)	Country A – Country B NTC (MW)	Country B – Country A Exchanges for Adequacy (GWh)	Country B – Country A NTC (MW)
Country A	Country B				
DZ00	MA00	0	600	0	300
DZ00	TN00	24	250	0	250
EG00	JO00	20	450	0	450
EG00	LY00	202	180	0	0
ES00	MA00	0	900	0	600
LY00	TN00	0	250	218	250
JO00	LB00	685	250	0	0

Exporting electricity from Egypt to Jordan positively contributes to enhancing Jordan's adequacy. Furthermore, Egypt and Jordan are actively exporting approximately 255 GWh to meet Sudan and Palestine's energy needs, while Jordan is exporting approximately 64 GWh to support Iraq's energy demands.

A notable example of how countries respond to acute adequacy pressures occurred last summer on the Tunisia–Algeria (TN–DZ) corridor, where the exchange was increased to 700 MW, well above the established NTC, to address a significant adequacy shortfall in Tunisia. While this enabled Tunisia to meet its demand, it meant that the N-1 security criterion was no longer being observed on that interconnection for the duration of that period, illustrating the operational trade-off that countries sometimes accept when facing summer peak stress. Given that similar demand pressures are anticipated this coming summer, it is possible that Tunisia may once again need to exceed the NTC on this corridor to safeguard its adequacy.

The situation in Lebanon is markedly different, where cross-border interconnections and imported energy play a central role in the country's supply balance. However, despite contributing a reduction of approximately 10% in adequacy risk exposure, interconnection capacity alone remains insufficient to fully address Lebanon's adequacy challenges, and additional measures would be required to close the remaining gap.

5. Adequacy Situation at Country Level

5.1. Egypt

DEMAND

Egyptian seasonal weekly demand for summer, depicted in Figure 10, ranges from around 5,314 GWh to 6,255 GWh, while peak hourly

demand each week varies from 38.4 GW to 43.5 GW. It should be noted that weekly demand refers to the average values of all 36 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 36 analysed climatic years.

As we can observe in the figure below, maximum electricity needs are expected from the second half of July to the end of August (29th – 35th week), due to high temperatures and high cooling consumption, like the scenario in all other countries. It should be noted that during the summer season, maximum hourly demand changes by around 12%.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
EG - SO 2026 - average Weekly consumption (GWh)	5,314	5,602	5,714	5,911	5,944	5,965	6,034	6,158	6,139	6,255	6,245	6,177	6,080	5,961	5,921	5,759	5,587	5,448	5,349
EG - SO 2026 - P95 - Weekly Peak Demand across climatic years (MW)	40,123	40,468	41,674	44,066	42,429	42,656	42,809	43,316	41,938	43,572	42,744	42,780	42,074	41,689	40,607	40,380	38,974	38,483	39,059

LOW HIGH

Figure 10 Seasonal weekly demand in Egypt.

SUPPLY AND NETWORK OVERVIEW

Egypt's generation mix is heavily dominated by natural gas, which accounts for most of the available installed capacity, reflecting the country's long-standing reliance on fossil fuel-based generation. Renewable energy sources — primarily solar, with a modest wind contribution — and hydropower together represent a growing but still relatively limited share of the mix, supplemented by early-stage battery storage deployment. Total installed capacity comfortably exceeds peak demand, and when combined with available import capacity from Jordan and Saudi Arabia, Egypt maintains a solid adequacy buffer. In terms of both system size and demand, Egypt is the largest power system among all analysed countries.

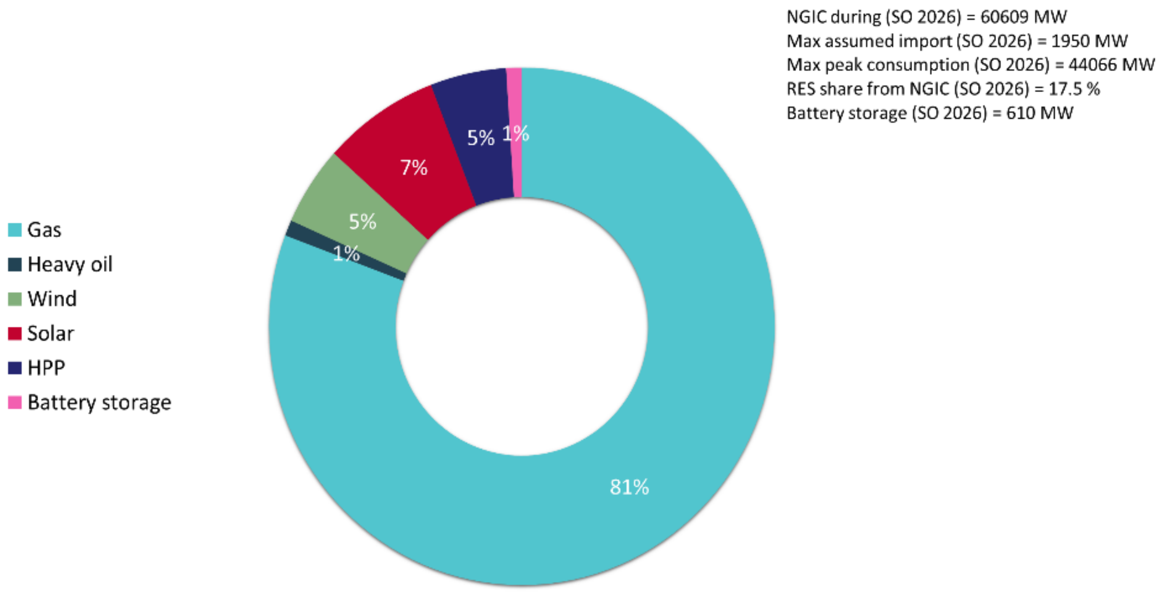


Figure 11 Available installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Egypt.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 12. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation. Egyptian average available TPP capacity fluctuates in this period due to derating and planned and forced outages. The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates around 42 GW.

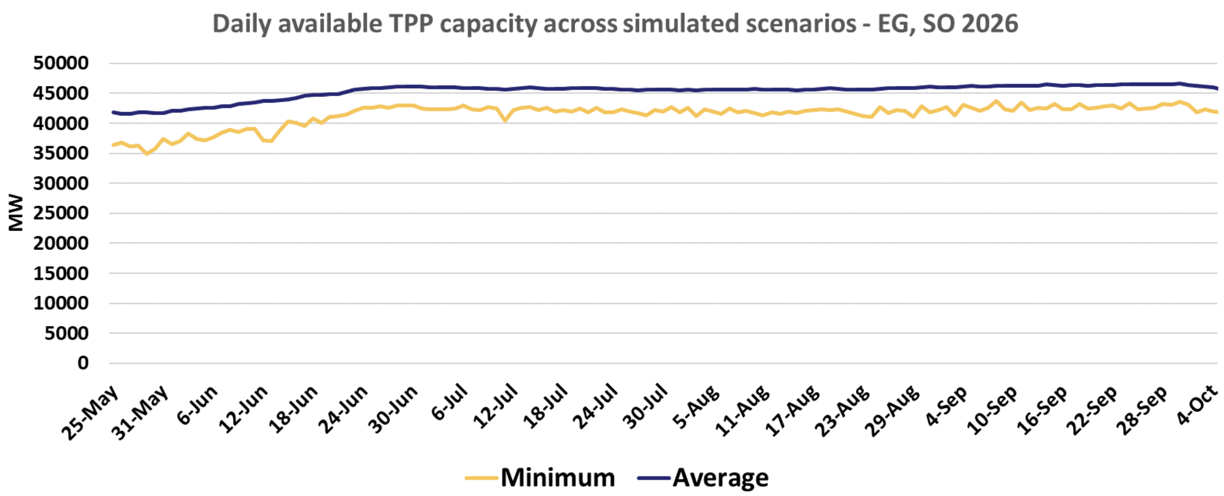


Figure 12 Average and minimum TPP available capacity among all simulated MC years in Egypt.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 13. It represents the difference between available and activated TPP capacities across the summer season from late May to early October 2026. The worst-case hourly TPP margin fluctuates significantly throughout the season, generally ranging between near-zero and approximately 6 GW. The lowest margins are observed at several points, particularly in late June, mid-July, late July, and early August, indicating periods of tightest system stress. In contrast, the highest margins are recorded towards the end of September.

Overall, the TPP capacity margin remains positive throughout the entire analysed period, meaning Egypt does not face thermal adequacy shortfalls during the summer season of 2026. The consistently high margins across most of the season reflect Egypt's strong thermal reserve levels and significant export capability that could support neighbouring countries experiencing adequacy deficits.

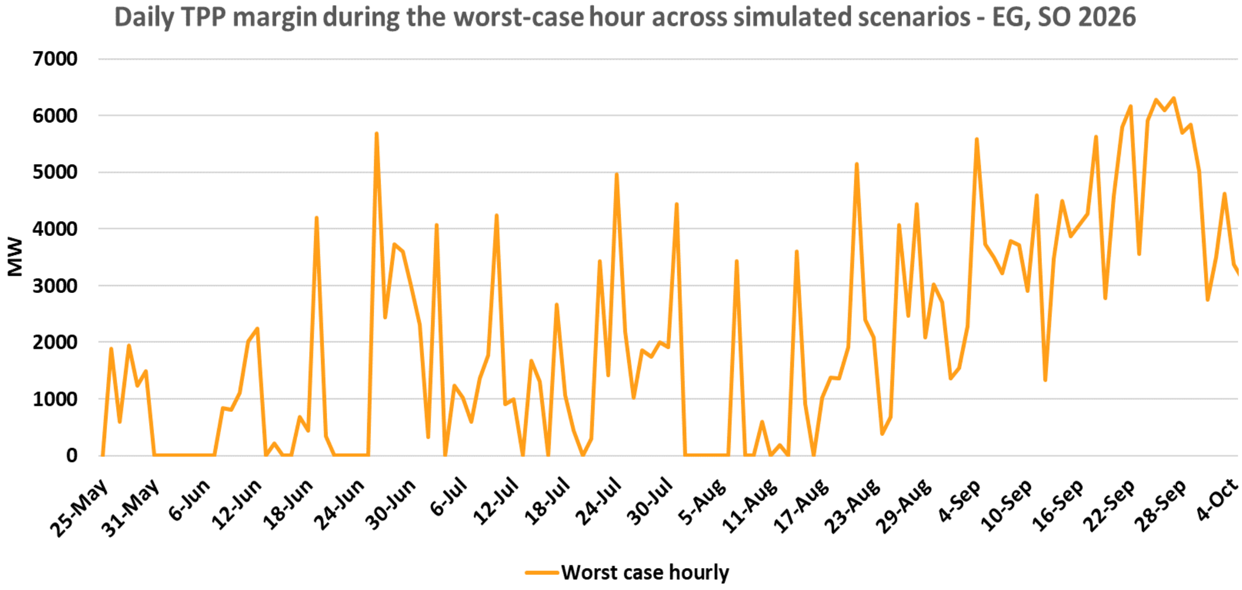


Figure 13 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Egypt.

ADEQUACY ASSESSMENT

No adequacy concerns are detected for either analysed operational mode in the case of Egypt.

5.2. Jordan

DEMAND

Jordan's seasonal weekly demand in summer, depicted in

Figure 14, ranges from around 493 GWh to 600 GWh (with fluctuation at the level of 17%), while peak hourly demand in each week ranges from 4,115 MW to 5,624 MW, which presents even higher fluctuation of 26%. It should be noted that weekly demand refers to the average values of all 36 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 36 analysed climatic years.

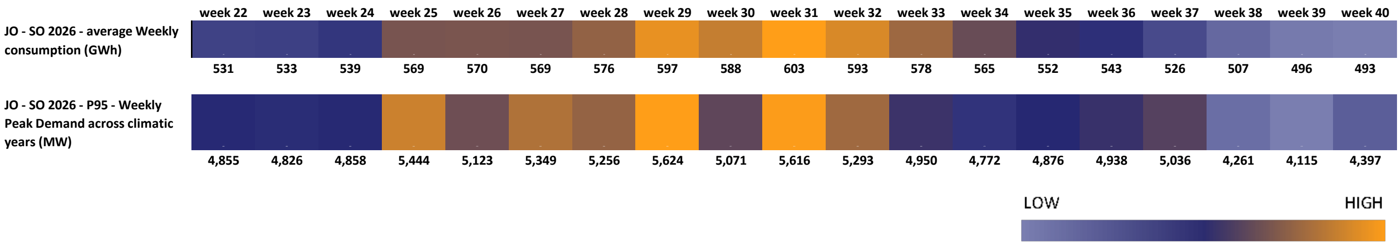


Figure 14 Seasonal weekly demand in Jordan.

SUPPLY AND NETWORK OVERVIEW

Jordan's generation mix is dominated by natural gas, which accounts for most of the installed capacity, complemented by a notable and growing renewable energy presence. Solar energy represents the most significant RES contribution, making up nearly a third of total installed capacity, while wind and oil shale account for smaller but meaningful shares. Overall, renewables constitute 38.2% of NGIC — one of the highest RES shares among the assessed countries — reflecting Jordan's strong commitment to clean energy diversification.

Total available installed capacity, when combined with available import capacity from Egypt, comfortably exceeds peak demand, confirming an adequate generation buffer under normal operating conditions.

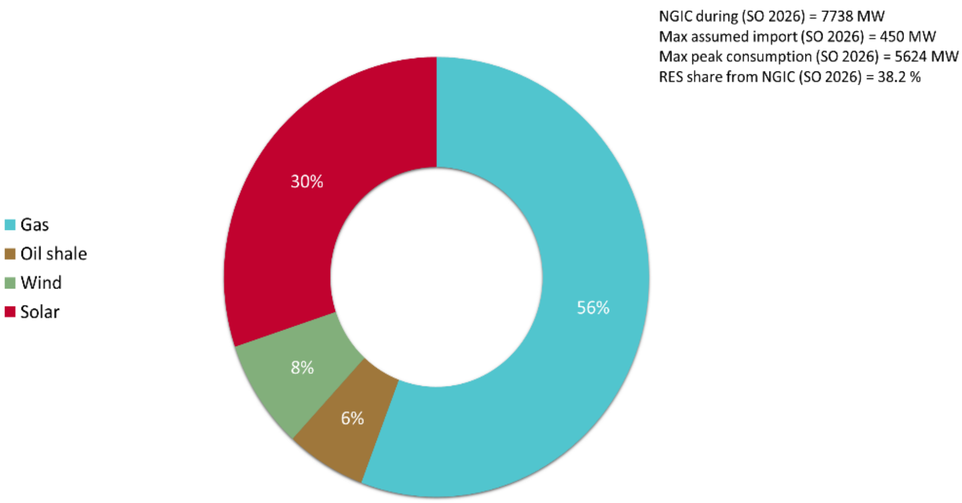


Figure 15 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Jordan.

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages, is shown in Figure 16. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation. The average available TPP capacities among all simulated MC years start from 3,800 MW and rise to 4,400 MW in early July due to maintenance stops aimed at meeting the demand during the summer season. The minimal average daily available TPP capacity among all simulated MC years ranges from 2,700 MW to 3,800 MW.

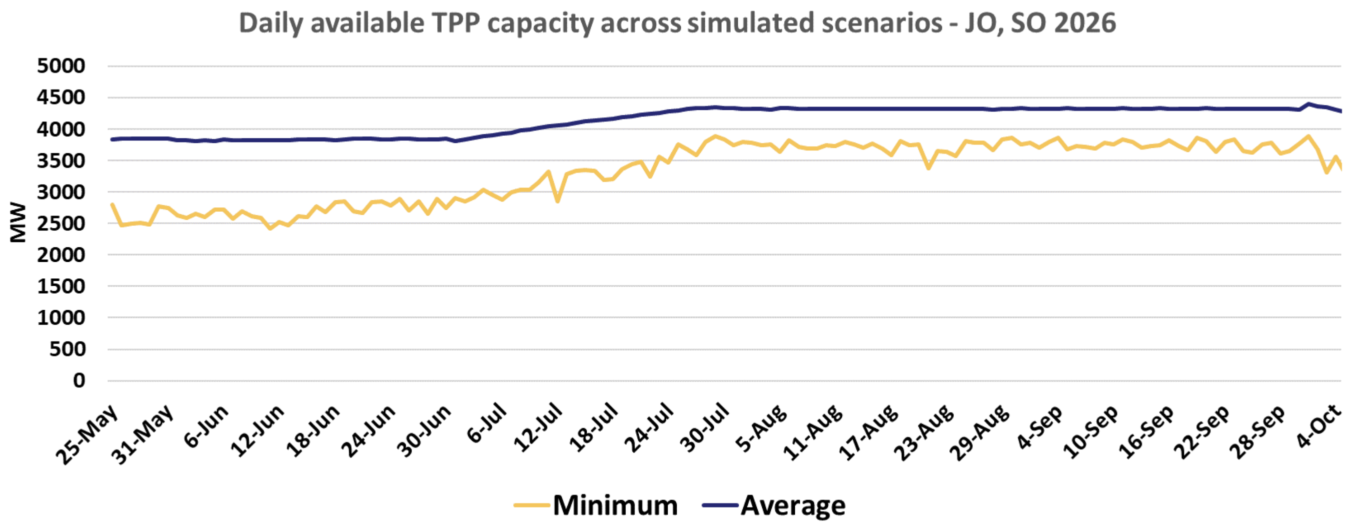


Figure 16 Average and minimum TPP available capacity among all simulated MC years in Jordan.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 17. The daily TPP margin during the worst-case hour across simulated scenarios tells a clear story about Jordan's adequacy risk during SO 2026. For most of the summer season — from late May through mid-August — the worst-case TPP margin sits at or near zero, meaning that in the most stressed simulated scenarios, thermal capacity is fully utilised with virtually no buffer remaining.

From late August onwards, brief spikes in the worst-case margin appear, peaking at around 150-210 MW in mid-to-late September. Rather than indicating an improvement, these spikes most likely reflect the onset of planned maintenance and reduced demand as the summer peak subsides.

The persistent near-zero margin through the core summer months confirms that Jordan's system operates with very little headroom under stressed conditions, and that the 450 MW import capacity from Egypt plays a critical role in preventing supply shortfalls during peak demand hours.

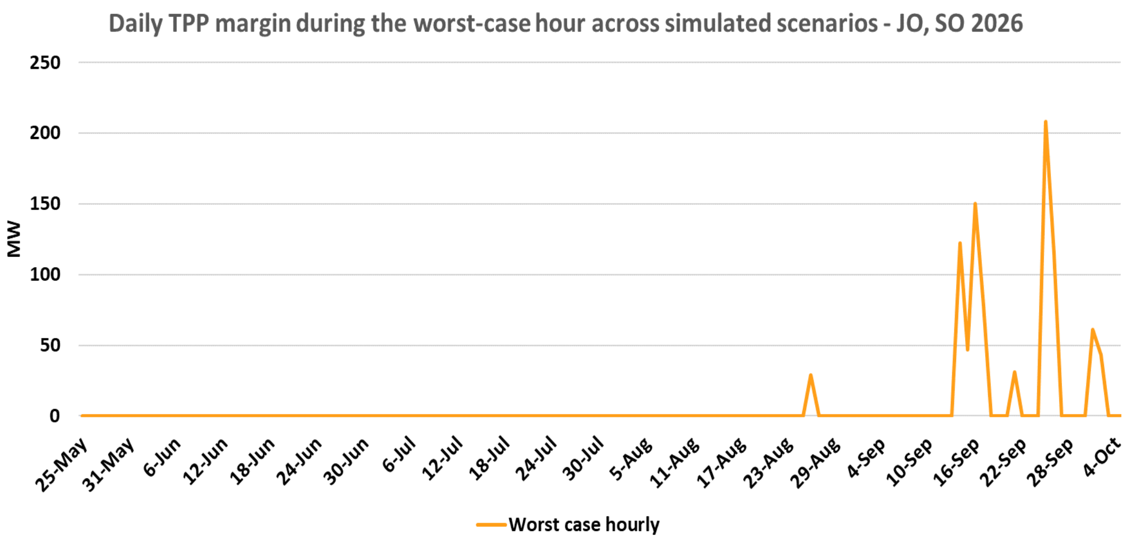


Figure 17 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Jordan.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is shown in Figure 18, shows the daily distribution of LOLE and EENS across the summer season for Jordan under both isolated and interconnected operation.

On the right-hand side of the figure, LOLE and EENS for the entire season for both system operation modes are provided.

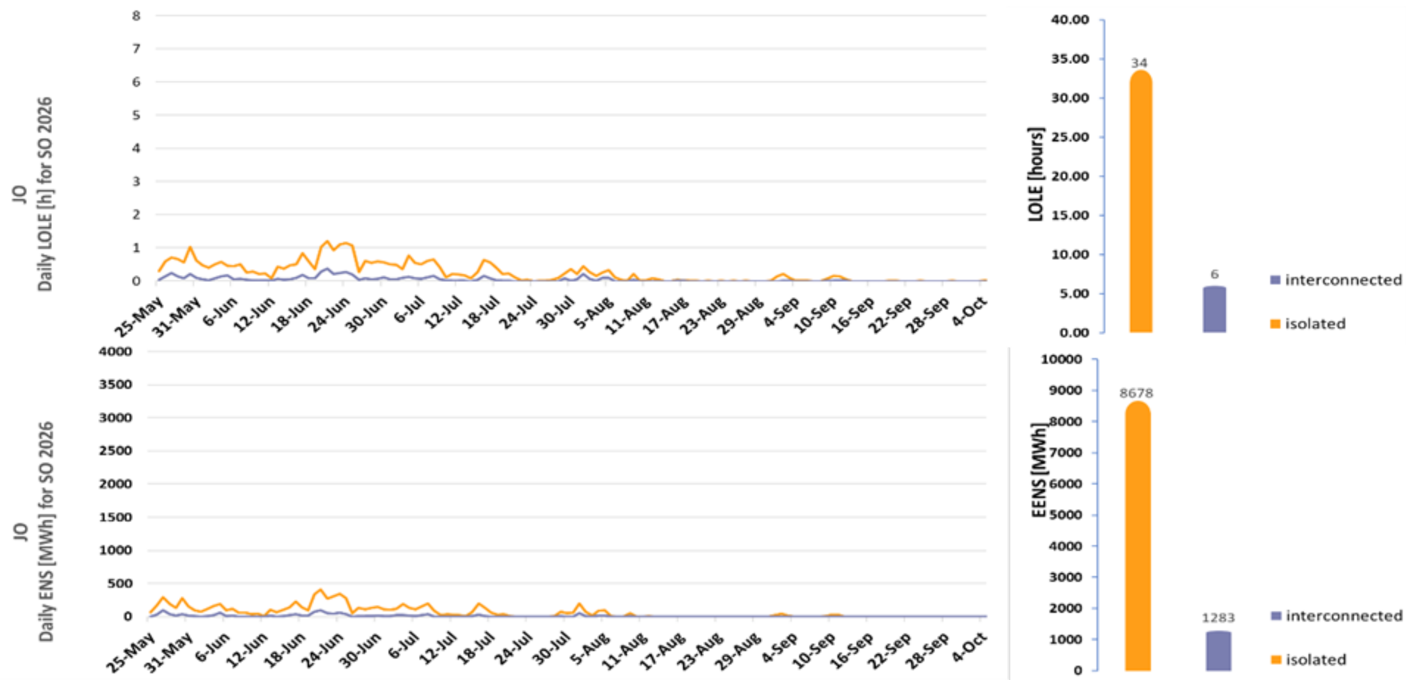


Figure 18 Daily LOLE and EENS for the interconnected and isolated operation modes in Jordan.

In isolated mode, adequacy risk is spread across the season but remains modest, with daily LOLE values rarely exceeding one hour and daily ENS peaking at around 300-400 MWh during June. Risk is most pronounced in the first half of the season, gradually tapering off from August onwards as demand eases.

Interconnection with Egypt effectively suppresses most of this risk, bringing daily LOLE and ENS values close to zero throughout the season. At the seasonal level, the contrast is clear — isolated LOLE of 34 hours and EENS of 8,678 MWh are reduced to just 6 hours and 1,283 MWh respectively under interconnected operation. This confirms that while Jordan's adequacy situation is manageable even in isolation, regional interconnection provides a meaningful and reliable safety net, particularly during the peak summer months.

5.3. Lebanon

DEMAND

Lebanon's seasonal weekly demand in summer, depicted in Figure 19, ranges from around 395 GWh to 485 GWh, while peak hourly demand each week ranges from 3,220 MW to 3,800 MW. It should be noted that weekly demand refers to the average values of all 36 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 36 analysed climatic years. Maximum electricity needs are expected during weeks 31 & 32 of 2026, due to high temperatures and increased cooling demand. It should be noted that the operation of Lebanon's power system is especially difficult, with a continuous lack of supply and organised regular load shedding.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
LB - SO 2026 - average Weekly consumption (GWh)	395	406	418	435	442	450	462	476	473	485	479	472	471	458	445	436	423	415	405
LB - SO 2026 - P95 - Weekly Peak Demand across climatic years (MW)	3,328	3,424	3,331	3,518	3,488	3,610	3,648	3,717	3,655	3,800	3,659	3,626	3,492	3,477	3,454	3,411	3,257	3,246	3,220

LOW HIGH

Figure 19 Seasonal Weekly demand in Lebanon.

SUPPLY AND NETWORK OVERVIEW

Lebanon's generation mix presents a unique and challenging picture compared to other countries in the region. While the chart shows "Other Non-RES" and "Light oil" together accounting for the majority of installed capacity, the reality on the ground is more complex — most thermal units were originally designed to run on natural gas, but in the absence of a functioning gas supply, they have been forced to switch to oil, significantly increasing operating costs and reducing reliability. A portion of these units are so expensive to operate that they remain effectively shut down, further constraining the available generation fleet.

Solar capacity — predominantly rooftop installations — represents the largest single technology share at 38% of NGIC, reflecting a remarkable grassroots energy transition driven not by policy but by necessity, as households and businesses seek alternatives to an unreliable grid. Hydropower contributes a further 7%.

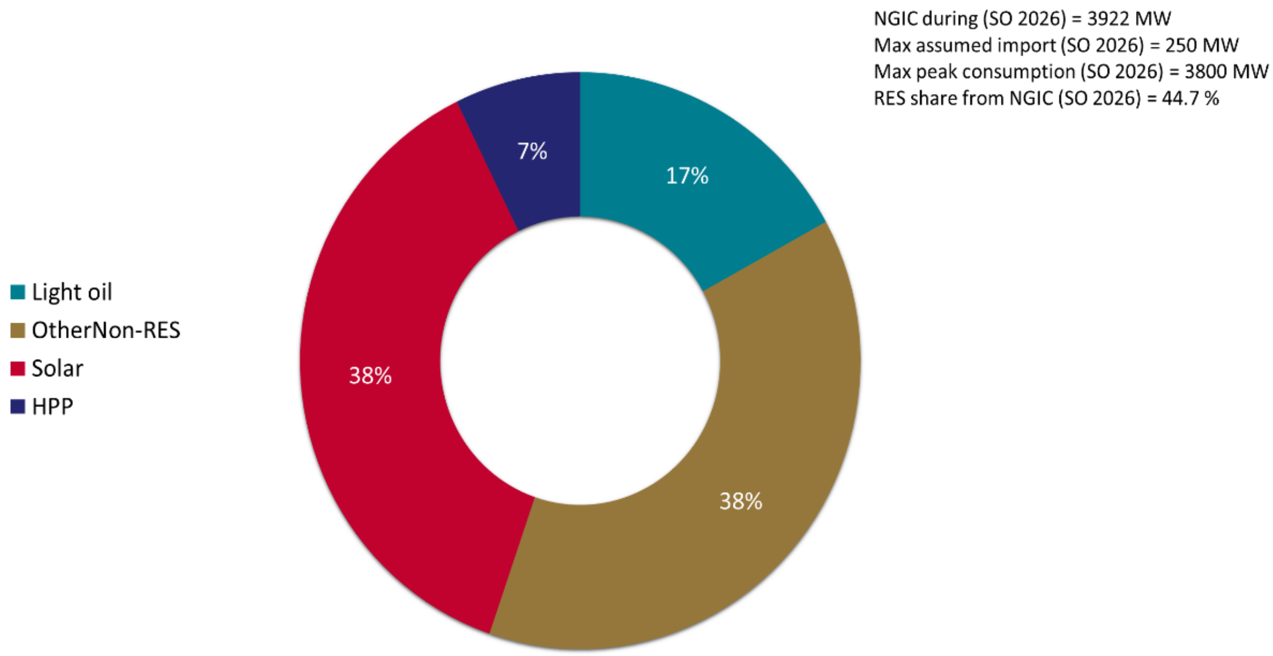


Figure 20 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Lebanon.

Overall, renewables account for 44.7% of NGIC — the highest RES share among all assessed countries — though this is largely a consequence of system dysfunction rather than a planned energy transition.

Total installed capacity is nominally close to peak demand but given the significant share of capacity that is either unavailable or prohibitively expensive to dispatch, Lebanon's effective generation margin is considerably tighter than the headline figures suggest. The growing role of private diesel generators further illustrates the depth of the country's supply crisis — a parallel, unregulated generation sector that has effectively become a primary source of electricity for many Lebanese consumers.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 21 Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation.

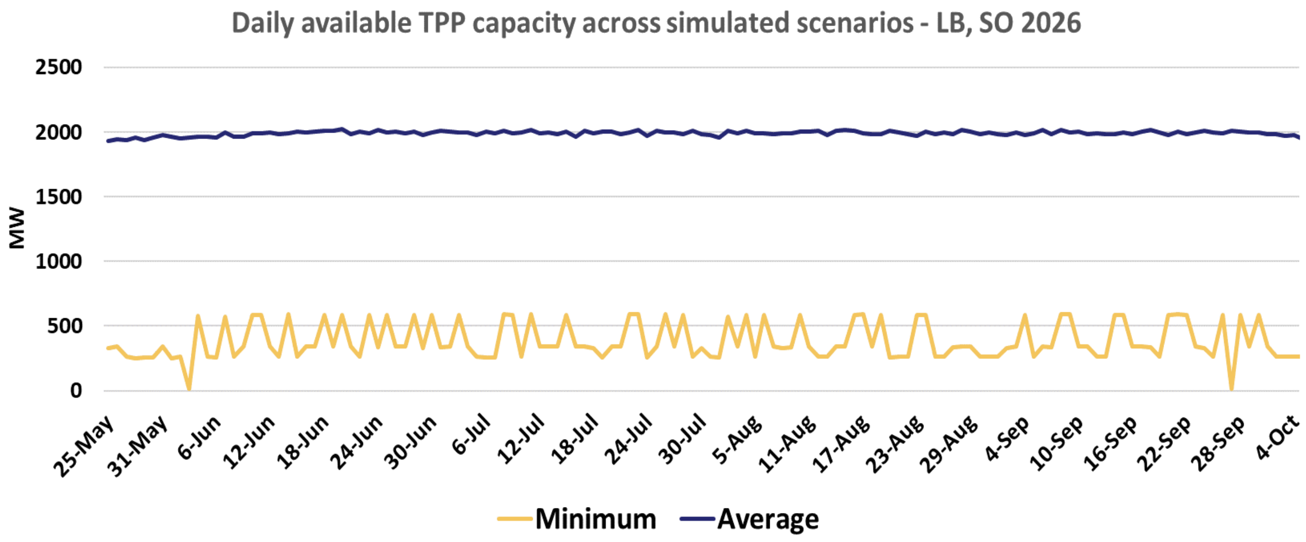


Figure 21 Average and minimum TPP available capacity among all simulated MC years in Lebanon.

It should be noted that the total NGC in Lebanon is lower than the maximum expected hourly demand, which points to a challenging system operation and dependence on import. The average daily available TPP capacity among all simulated MC years is only around 2,000 MW.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 22. It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.

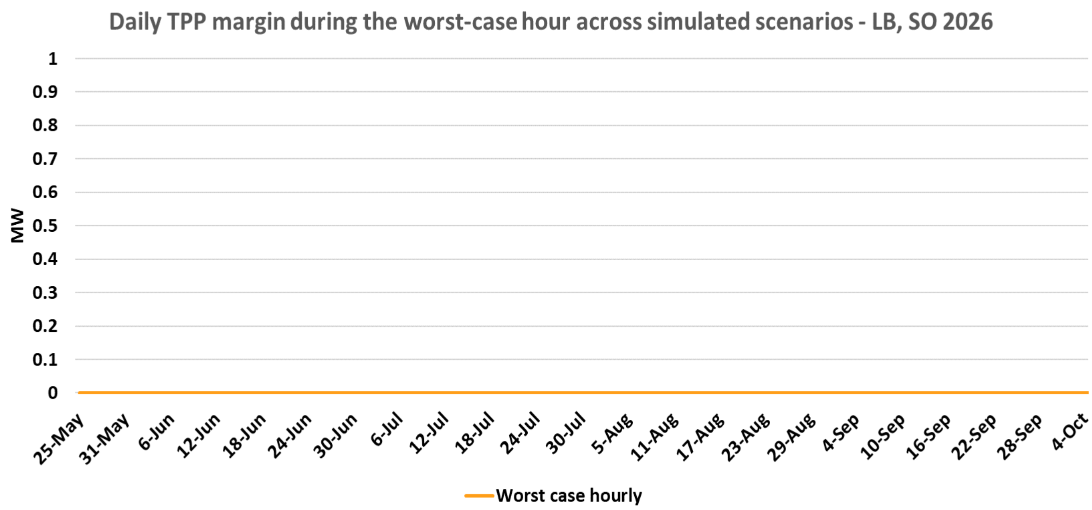


Figure 22 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Lebanon.

Adequacy assessment

The temporal distribution of detected adequacy risk is shown in Figure 23 for both modes of operation: hypothetically interconnected and isolated. The first picture depicts daily LOLE distribution, while the second depicts daily EENS. Lebanon's adequacy situation stands in a category of its own. Unlike any other country in the region, load shedding is not an exceptional event — it is a daily reality throughout the entire summer season.

The daily LOLE chart confirms this starkly. Under isolated operation, daily LOLE consistently ranges between 15 and 24 hours, meaning Lebanon is unable to supply its load for most of every single day across the season. Even under interconnected operation, daily LOLE remains between 10 and 20 hours — a marginal improvement that does nothing to fundamentally alter the picture.

At the seasonal level, isolated LOLE reaches 2,857 hours with EENS of approximately 2.9 TWh, while hypothetical interconnected operation reduces these to 2,457 hours and 2.2 TWh respectively. The weekly pattern visible in the ENS chart reflects the weekly demand cycle, but the underlying message is consistent — there is no week, and effectively no day, without significant supply shortfalls.

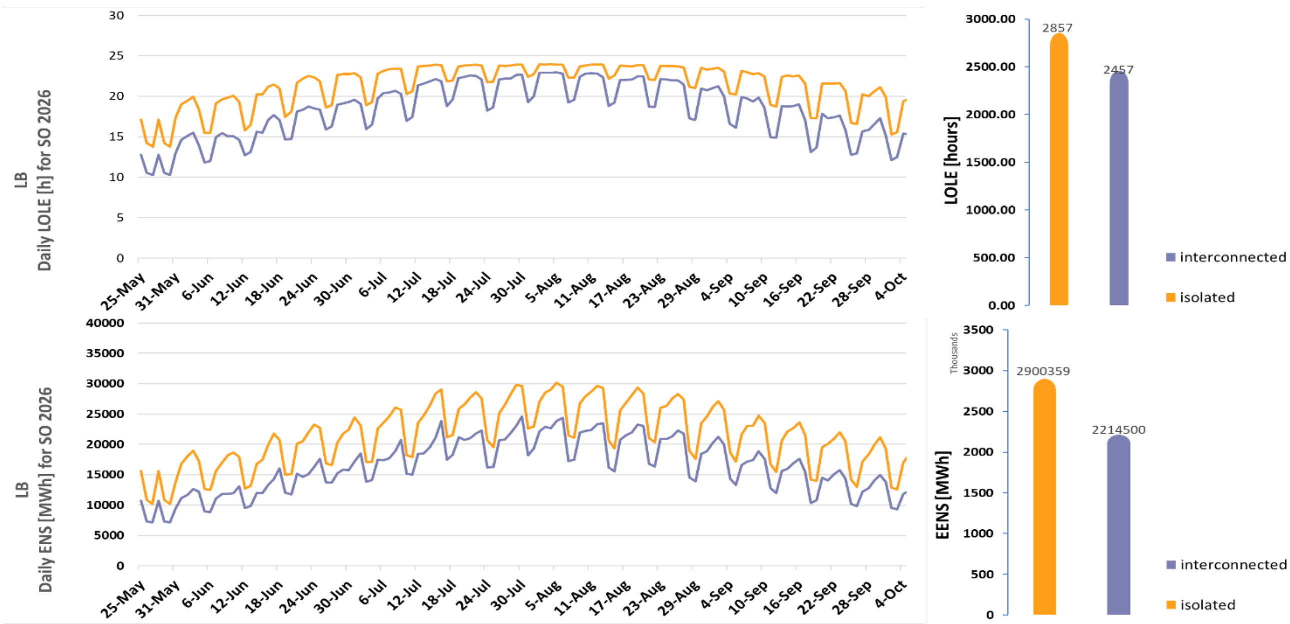


Figure 23 Daily LOLE and EENS for the interconnected and isolated operational modes in Lebanon.

Hypothetical Interconnection with Jordan provides partial relief but cannot resolve what is fundamentally a structural generation crisis. Lebanon's adequacy challenge requires far more than regional support — it demands urgent and substantial domestic investment in generation capacity.

5.4. Libya

DEMAND

Libya's seasonal weekly demand in summer, depicted in

Figure 24, ranges from around 1,085 GWh to 1.4 TWh, while peak hourly demand each week ranges from 8,100 MW to 9,480 MW. It should be noted that weekly demand refers to the average values of all 36 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 36 analysed climatic years.

Maximum electricity needs to consumptions are expected in August (week 31).

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
LY - SO 2026 - average Weekly consumption (GWh)	1,063	1,124	1,167	1,191	1,247	1,324	1,339	1,353	1,365	1,390	1,380	1,367	1,342	1,326	1,285	1,247	1,178	1,135	1,085
LY - SO 2026 - P95 - Weekly Peak Demand across climatic years (MW)	8,995	8,626	9,324	9,045	9,176	9,480	9,404	9,385	9,325	9,467	9,388	9,253	9,198	9,071	9,045	8,720	8,388	8,105	8,120

LOW HIGH

Figure 24 Seasonal weekly demand in Libya.

SUPPLY AND NETWORK OVERVIEW

Libya's generation mix is entirely fossil fuel-based, with no renewable energy contribution recorded for SO 2026 — the only country in the assessed region with a zero RES share. Natural gas dominates the mix, accounting for most of the installed capacity, with light oil and heavy oil making up the remainder.

A notable and concerning feature of Libya's system is that total installed capacity is nominally close to — and in some scenarios falls below — peak demand. This leaves virtually no buffer before imports become necessary, making the 430 MW available from Tunisia and Egypt not just a convenience but an operational necessity.

Libya's adequacy challenge is therefore not primarily about the generation mix, but about the reliability and availability of its existing fleet — ageing thermal units operating without any renewable backup or diversification, in a system where the margin between installed capacity and peak demand is razor thin.

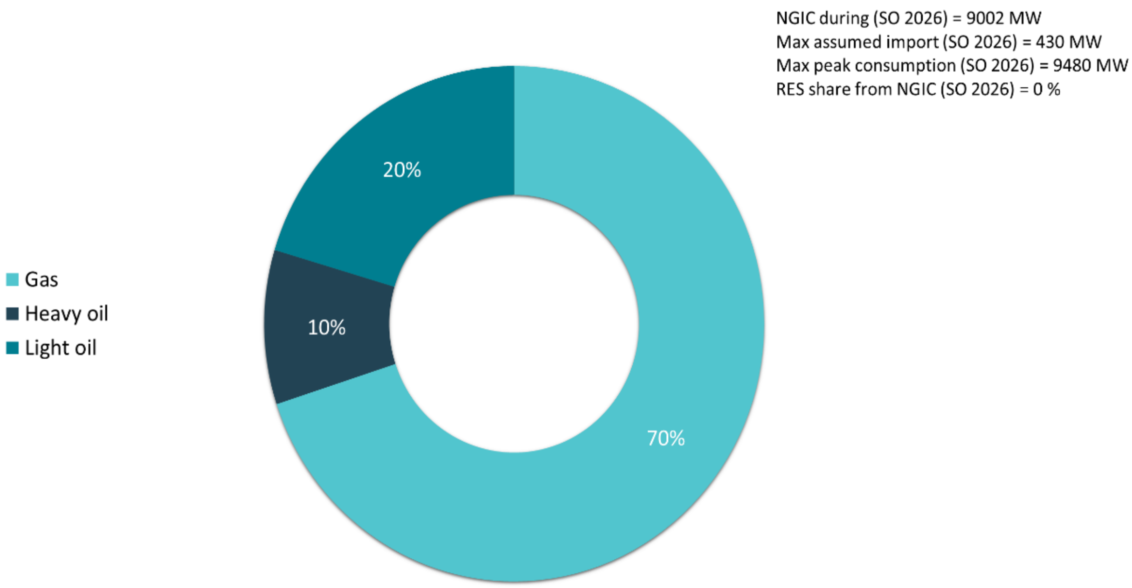


Figure 25 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Libya.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 26. Each daily value represents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation. Libya's average available thermal capacity is stable at the level of 8,400 MW. The minimal daily available TPP capacity among all analysed MC years ranges from 5,300 MW to 7,200 MW.

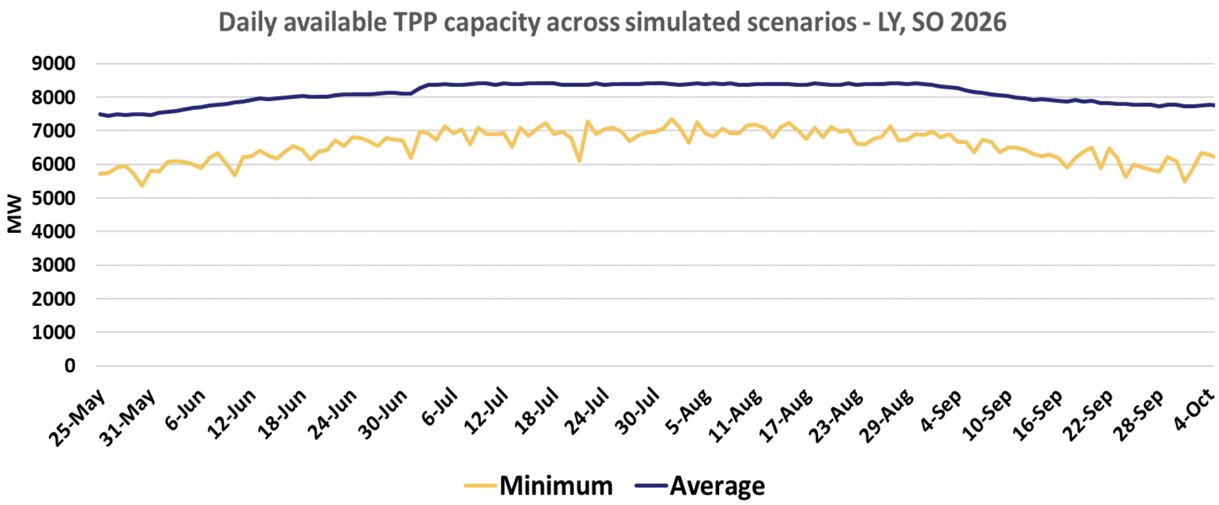


Figure 26 Average and minimum TPP available capacity among all simulated MC years in Libya.

As a result of system simulation, the minimum hourly TPP margin among all simulated MC years for each day is depicted in Figure 27, It represents the difference between available and activated TPP capacities. The daily TPP margin during the worst-case hour tells an unambiguous story — the line is flat at zero across the entire summer season, from late May through early October, without a single day of positive margin. This means that in the worst simulated scenario, Libya's thermal fleet is fully utilised every single day of the season, leaving absolutely no buffer to absorb any unexpected demand spike or generation outage.

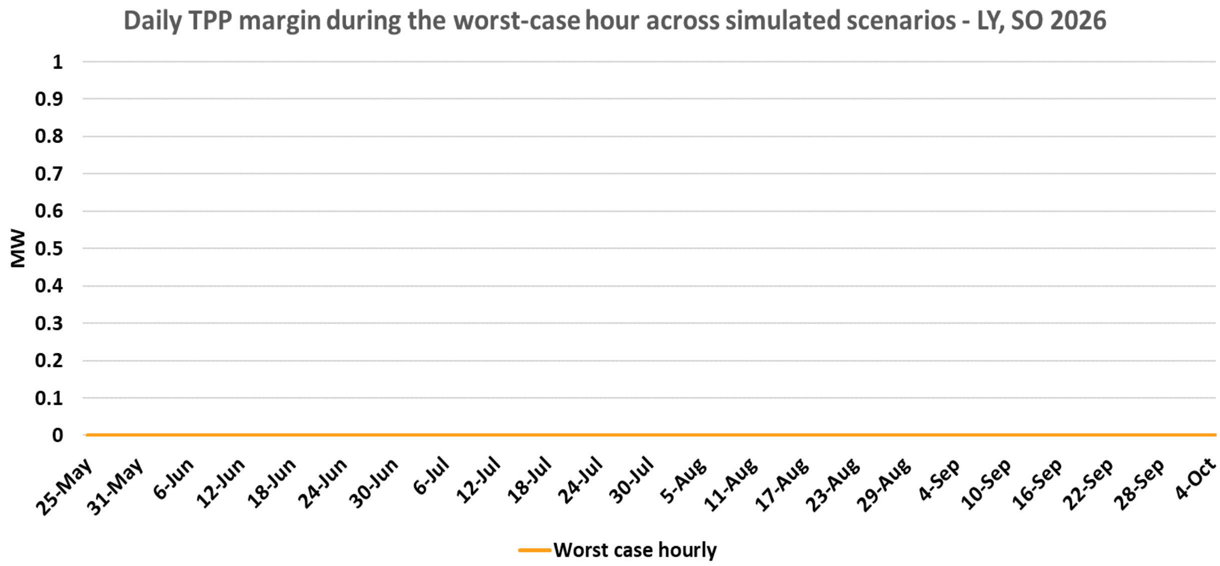


Figure 27 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Libya.

This is the clearest possible signal of a system operating permanently at its limits, where any unplanned event — a forced outage, a fuel supply disruption, or an unusually hot day — directly translates into supply shortfalls with no margin to compensate.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is shown in Figure 28 for both modes of operation: hypothetically interconnected and isolated. The first picture depicts daily LOLE distribution, while the second depicts daily EENS.

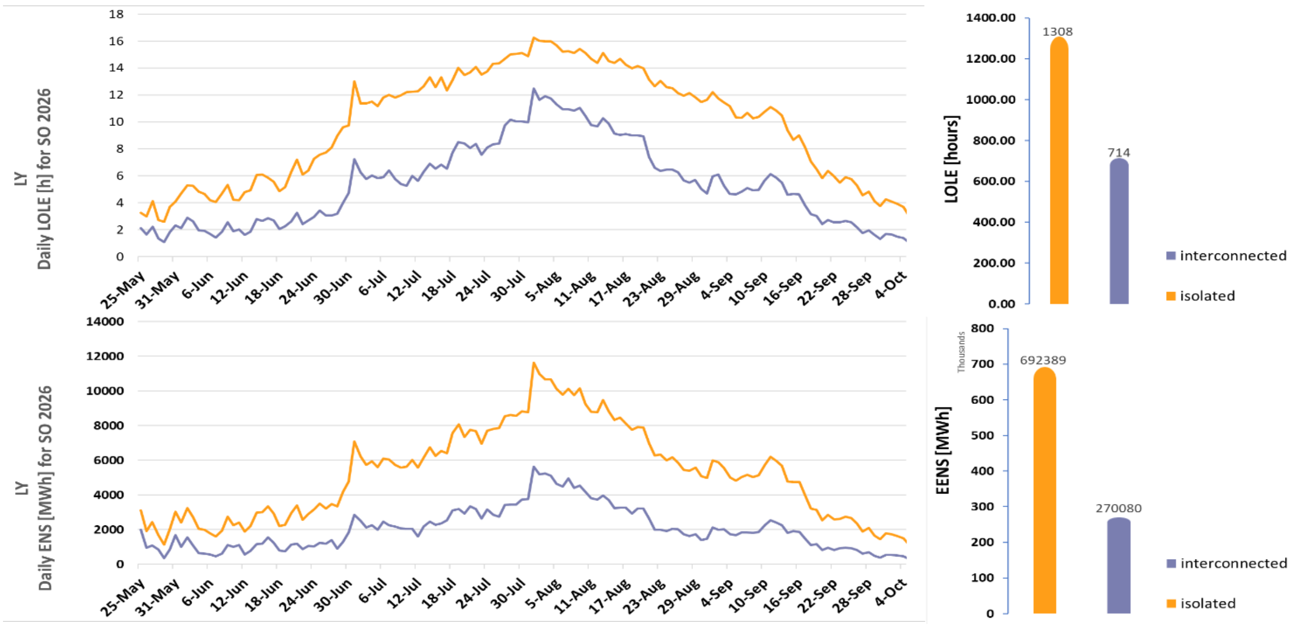


Figure 28 Daily LOLE and EENS for the interconnected and isolated operational modes in Libya

Libya's adequacy results paint a concerning picture throughout the entire summer season. Unlike Jordan, where risk is modest and concentrated in specific periods, Libya experiences supply shortfalls every single day from late May through early October — in both isolated and interconnected modes.

In isolated operation, daily LOLE rises steadily from around 5 hours in late May to a peak of approximately 16 hours in early August before gradually easing towards season end. The ENS profile mirrors this pattern, with daily unserved energy reaching particularly severe levels through July and August — the heart of the summer peak.

Interconnection with Tunisia and Egypt provides meaningful but partial relief, roughly halving daily LOLE and ENS values throughout the season. At the seasonal level, isolated LOLE of 1,308 hours and EENS of 692 GWh are reduced to 714 hours and 270 GWh under interconnected operation — a significant improvement, but one that still leaves Libya with an unacceptably high level of supply risk.

The seasonal pattern is clear — Libya's adequacy challenge peaks in mid-summer when demand is highest and the thermal fleet is under maximum stress, and no amount of regional support can fully compensate for the scale of the underlying generation deficit.

5.5. Morocco

DEMAND

Moroccan summer seasonal weekly demand, depicted in

Figure 29, ranges from around 973 GWh to 1.14 TWh, while peak hourly demand each week ranges from 7,460 MW to 8,420 MW. It should be noted that weekly demand refers to the average values of all 36 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 36 analysed climatic years. Maximum electricity needs are expected in July and August.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
MA - SO 2026 - average Weekly consumption (GWh)	973	1,047	1,044	1,073	1,094	1,104	1,118	1,133	1,138	1,121	1,129	1,120	1,070	1,076	1,092	1,070	1,059	1,035	1,030
MA - SO 2026 - P95 - Weekly Peak Demand across climatic years (MW)	7,648	7,690	7,700	8,063	8,211	8,373	8,397	8,416	8,418	8,349	8,254	8,226	7,953	8,012	8,007	7,829	7,752	7,509	7,460

LOW HIGH

Figure 29 Seasonal weekly demand in Morocco.

SUPPLY AND NETWORK OVERVIEW

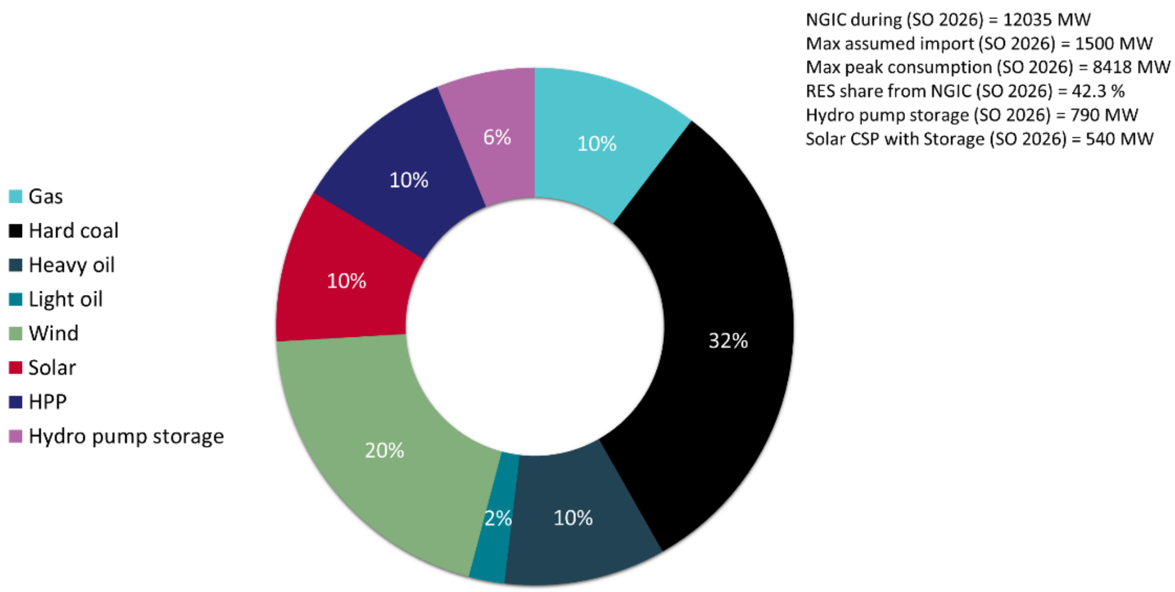


Figure 30 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Morocco

Morocco stands out as the most diversified generation mix among all assessed countries. Hard coal forms the backbone of the system, complemented by meaningful contributions from wind, hydropower, heavy oil, gas, and solar — a genuine multi-technology portfolio that no other country in the region can match.

Renewables account for 42.3% of NGIC, driven primarily by a strong wind presence and a growing solar contribution, further supported by storage-enabled technologies including hydro pump storage and solar CSP with storage. This combination of variable renewables with built-in storage capacity reflects Morocco's advanced position in the regional energy transition.

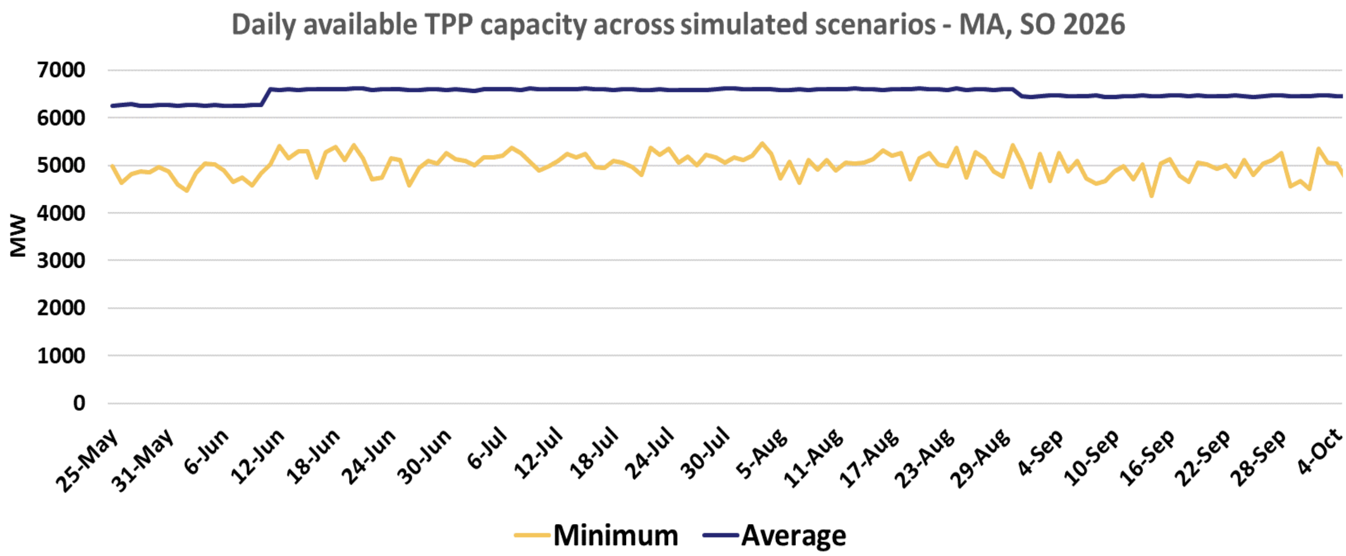


Figure 31 Average and minimum TPP available capacity among all simulated MC years in Morocco.

Total installed capacity comfortably exceeds peak demand, and with available import capacity from Spain, Morocco maintains a solid adequacy buffer. Morocco's well-balanced mix and strong generation surplus position it as one of the most reliable and resilient power systems in the region.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 32. Each daily value represents the average of all simulated MC years. These values are the same for the interconnected and isolated operational modes. The Moroccan average available TPP capacities among all simulated MC years level is stable, at around 6,600 MW. The minimal average daily available TPP capacity (minimum among all simulated MC years) ranges from 4,400 MW to 5,200 MW.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years on each day is depicted in Figure 32 It represents the difference between available and engaged TPP capacities.

Morocco's worst-case TPP margin tells a different story from Libya or Lebanon. While the margin does touch zero on several occasions throughout the summer — confirming that the system can be pushed to its limits under adverse scenarios — it also recovers quickly and maintains meaningful headroom on most days, with peaks reaching well above 500 MW and occasionally exceeding 1,000 MW. This variability reflects Morocco's diverse generation mix, where the interplay between thermal availability, wind output, and hydro conditions creates a dynamic but generally manageable margin profile. The dips to zero are real stress points, but they are transient rather than persistent — a fundamentally different risk profile compared to countries where zero margin is the norm rather than the exception. With import capacity from Spain available as a backstop, Morocco's system remains well-positioned to manage these occasional stress periods without compromising overall adequacy.

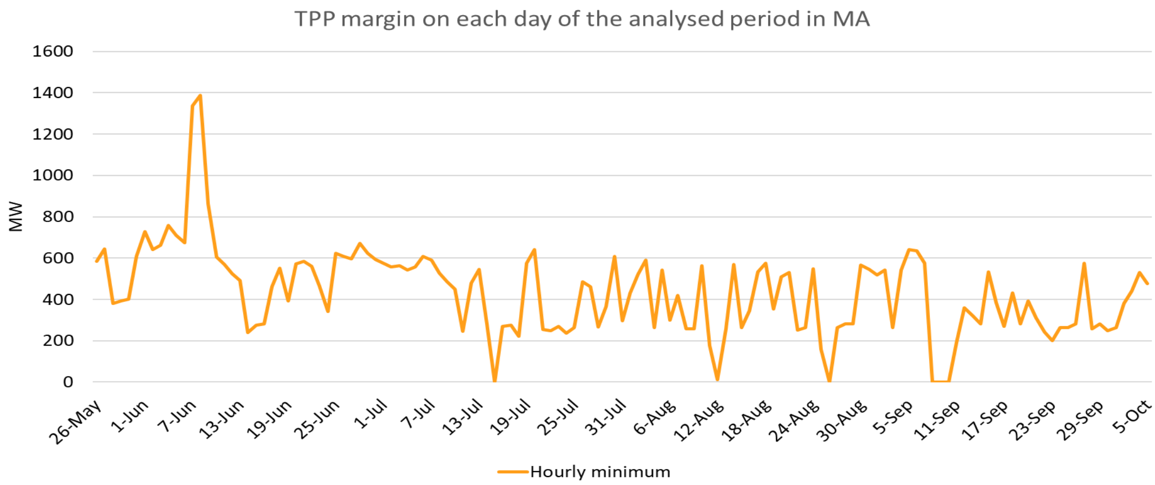


Figure 32 Minimum hourly TPP margin on each day of the analysed period in Morocco.

ADEQUACY ASSESSMENT

No adequacy concerns are detected for either analysed operational mode in the case of Morocco.

5.6. Tunisia

DEMAND

Tunisian seasonal weekly demand, depicted in Figure 33, ranges between 436 GWh and 619 GWh, while peak hourly demand ranges from 4,000 MW to 5,827 MW each week. It should be noted that weekly demand refers to the average values of all 36 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 36 analysed climatic years.

Maximum electricity needs are expected throughout July and August.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
TN - SO 2026 - average Weekly consumption (GWh)	436	461	479	522	541	550	566	588	594	619	607	582	563	567	546	519	487	467	458
TN - SO 2026 - P95 - Weekly Peak Demand across climatic years (MW)	4,002	4,297	4,724	5,000	5,524	5,003	5,389	5,646	5,280	5,827	5,568	5,424	5,321	5,282	4,924	4,540	4,187	4,170	4,484

LOW HIGH

Figure 33 Seasonal weekly demand in Tunisia.

SUPPLY AND NETWORK OVERVIEW

NGIC during (SO 2026) = 6146 MW
Max assumed import (SO 2026) = 500 MW
Max peak consumption (SO 2026) = 5827 MW
RES share from NGIC (SO 2026) = 16.7 %

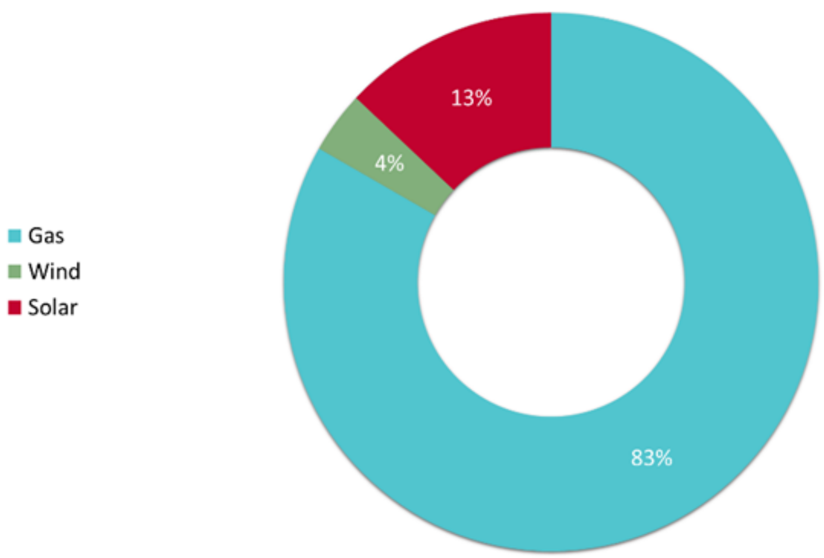


Figure 34 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Tunisia.

Tunisia's generation mix is heavily dominated by natural gas, which accounts for most of the installed capacity — a profile similar to Egypt but with a notably thinner adequacy buffer. Renewables, comprising solar, wind, and battery storage, represent a modest but growing share of the mix at 16.7% of NGIC, signalling early-stage diversification that has yet to meaningfully reduce the system's dependence on gas-fired generation.

What makes Tunisia's situation particularly notable is the very narrow gap between total installed capacity and peak demand. Even before accounting for forced outages or maintenance, the system has minimal headroom — making the 500 MW import capacity from neighbouring countries not a comfort measure but a practical necessity for day-to-day system balance.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 35. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated operational modes. The average available thermal capacity, across all 684 MC years, is approximately 5,000 MW. However, the minimum average daily available thermal capacity (the lowest value among all 684 MC years for each day) is lower, with a minimum of 3,100 MW.

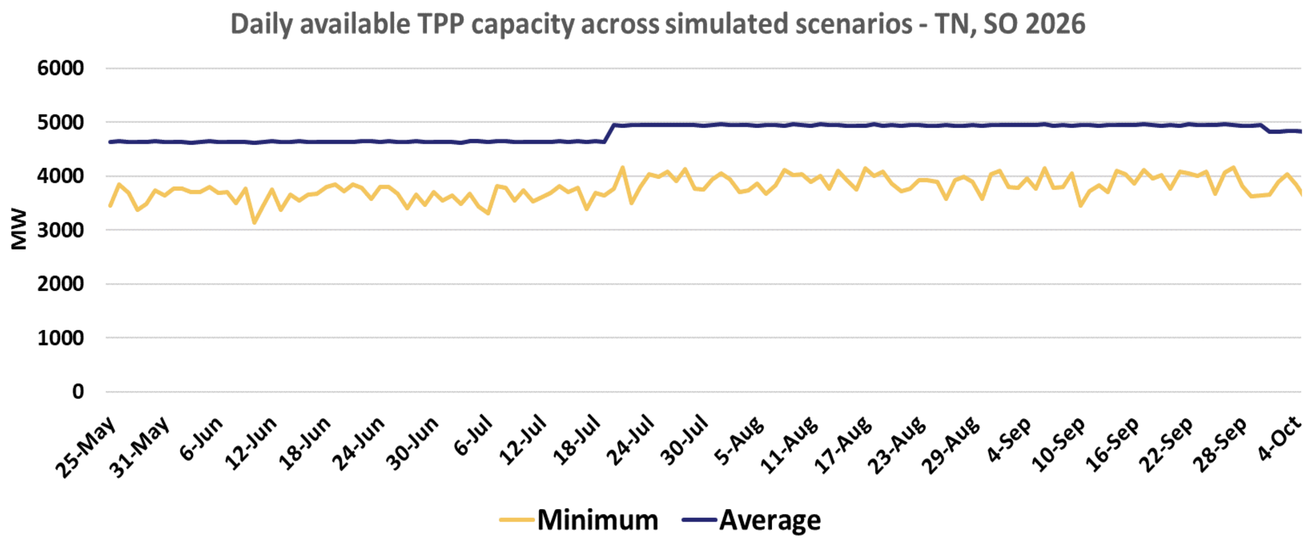


Figure 35 Average and minimum TPP available capacity among all simulated MC years in Tunisia.

As a result of system simulation, the minimum hourly TPP capacity margin on each day is depicted in Figure 36. It represents the difference between available and activated TPP capacities. Tunisia's worst-case TPP margin reveals a clear and concentrated vulnerability window. After some positive margin in late May and early June — where the system shows reasonable headroom — the margin collapses to zero from late June and remains flat throughout the entire July and August period. This two-month stretch of zero worst-case margin coincides precisely with the peak summer demand period, confirming that Tunisia's thermal fleet is fully stretched exactly when the system needs it most.

Some recovery appears from mid-September onwards as demand eases and maintenance windows open, but by then the critical adequacy risk period has already passed.

The message is clear — Tunisia's adequacy challenge is not spread across the season but concentrated in a well-defined summer peak window, making targeted capacity reinforcement and reliable import access during these months the most effective levers for improving system reliability.

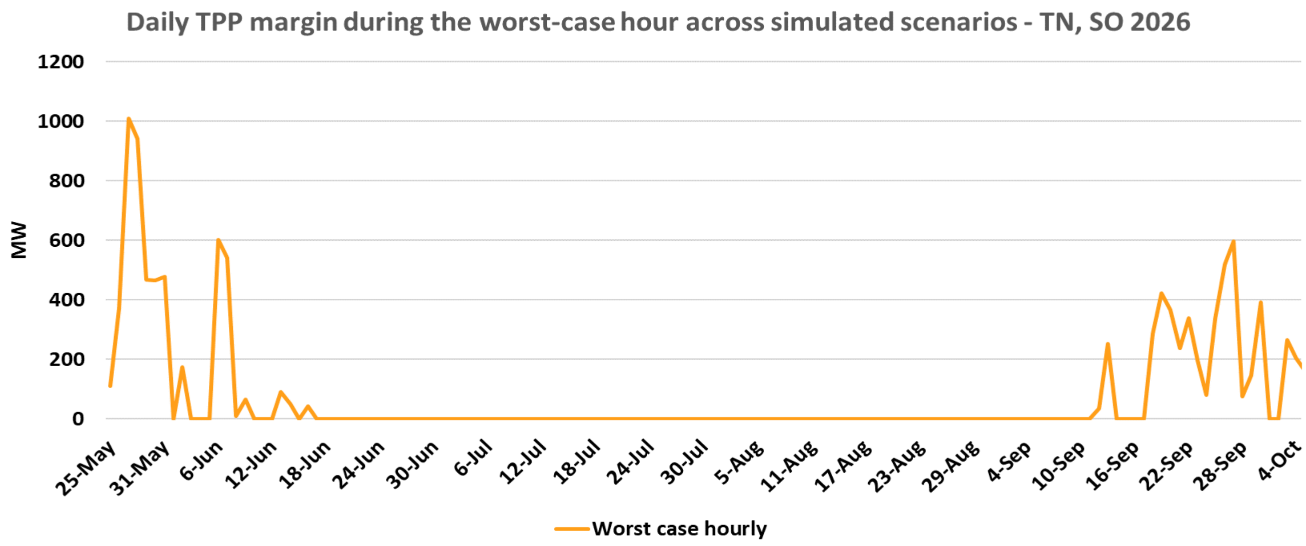


Figure 36 Minimum hourly TPP margin on each day of the analysed period in Tunisia.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is shown in Figure 37 for both the interconnected and isolated operational modes. The first image depicts the daily LOLE distribution, while the second depicts daily EENS.

Tunisia's adequacy risk follows a clear seasonal pattern. The first month of the season — through late June — is largely risk-free, with both daily LOLE and ENS values sitting at or near zero, reflecting higher thermal availability and lower demand during this period.

From late June through August, adequacy risk emerges and persists almost daily, peaking in late July and early August where daily LOLE reaches around 39 hours and daily ENS spikes above 12,000 MWh on the most stressed days. This critical window aligns directly with the period of maximum demand and lowest thermal availability due to forced outages and derating. Interconnection provides meaningful relief — visibly pulling down both daily LOLE and ENS curves — but does not eliminate the risk entirely.

From September onwards, risk fades rapidly as demand retreats, and both curves return to near zero for the remainder of the season. At the seasonal level, interconnection roughly halves Tunisia's adequacy risk, reducing isolated LOLE of 81 hours and EENS of 27,785 MWh to 39 hours and 12,570 MWh respectively.

One potential measure to further reduce adequacy risk would be increasing import capacity from Algeria. However, this would require exceeding current NTC limits, which raises concerns around N-1 compliance and cross-border security — a trade-off that would need careful technical assessment before any such measure could be considered.

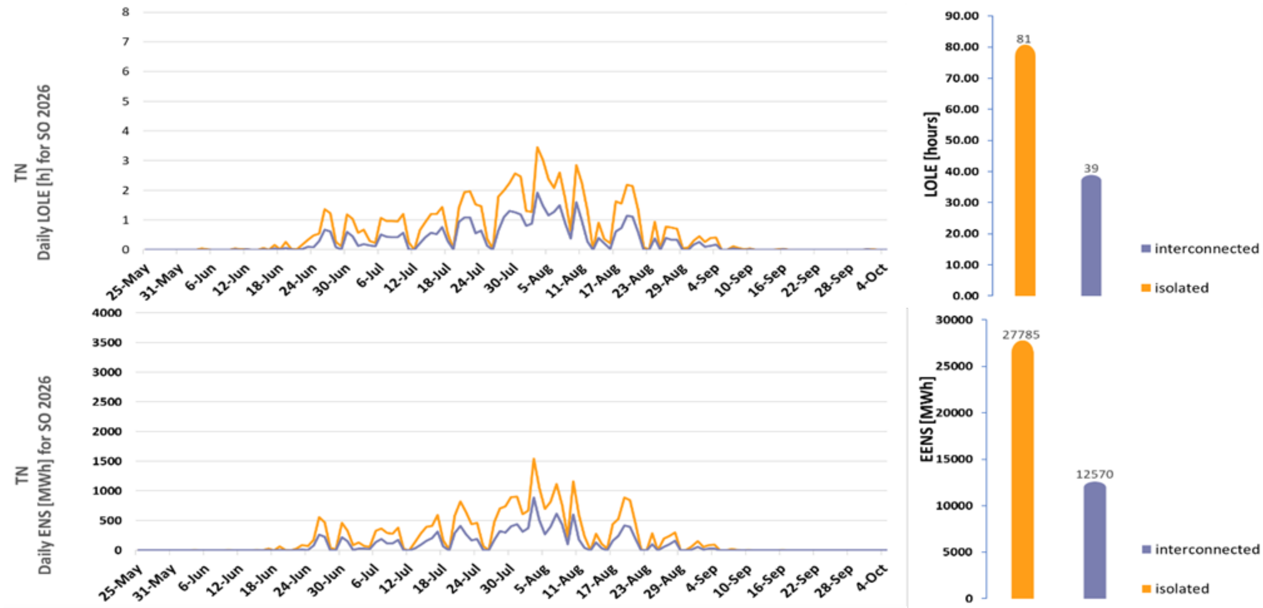


Figure 37 Daily LOLE and EENS for the interconnected and isolated operational modes.

6. Appendix

6.1. Approach and Methodology

6.1.1 Adequacy assessment methodology

This report presents the seasonal adequacy situation among non-EU Med-TSO members. With this assessment, Med-TSO is aligning with global best practices and with the latest development in EU regulations[5].

These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria. This approach is inevitable due to the stochastic nature of renewable energy systems (RES), their intermittency, and the power system operation based on open electricity market conditions, which raise the question of power system adequacy in the short-, mid- and long-term. Moreover, the integration of immense amounts of RES must be closely followed by the commissioning of devices that can provide adequate power system flexibility.

With all the changes in the electricity sector in Mediterranean countries, from the energy markets development, integration of renewable energy sources and efforts to decarbonise energy systems, adequacy monitoring becomes even more important.

The analyses have been carried out with the Antares-Simulator v8.6, considering the following aspects:

- The Antares–simulator (A New Tool for Adequacy Reporting of Electric Systems), developed by the French TSO RTE, was specifically designed and created to tackle generation adequacy assessments in a probabilistic manner.
- The Antares–simulator is well recognised and used by ENTSO-E for TYNDP and adequacy assessments. For example, the 2020 edition of the Mid-Term Adequacy Forecast (MAF) was conducted using Antares.
- The Antares–simulator was already used by Med-TSO in the Mediterranean Masterplan 2022.
- Antares is an Open-Source software, and therefore accessible to all Med-TSO members.

Within this seasonal assessment, short-term risks that might occur in the following four months, and that are likely to result in a significant deterioration of the electricity supply situation, are analysed.

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5 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en

The data collection process has been carried out by our members, and it includes the capture of all relevant data and information necessary to model the power systems of Med-TSO countries. As a general approach, a probabilistic Monte Carlo with Unit Commitment and Economic Dispatch (UCED) model has been used, ensuring interzonal and intertemporal correlation of model variables, and considering the specificities of the assessed geographical perimeter. The hourly resolution has been implemented in the model, and the Monte Carlo approach has been used to reflect the variability of weather, as well as the randomness of supply and transmission outages. Several Monte Carlo (MC) years are constructed to assess adequacy risks under various conditions for the analysed timeframe. For all these MC years, hourly calculations are performed for the whole geographical scope.

Figure 38 Probabilistic modelling general approach (source: ENTSO-E).

6.1.2 Adequacy indicators and results of the adequacy assessment

The seasonal adequacy assessment has been based on the following main indicators:

- **P95/P50 loss of load duration (P95/P50 LOLD).** While LOLD in a given geographical zone for a given period is the number of hours during which the zone experiences ENS during a single Monte Carlo sample/simulation year, P95/P50 LOLD are LOLD in more or less severe operational conditions.
  - P95: LOLD that happens once every 20 years.
  - P50: LOLD that happens once every 2 years.
- **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected (average) number of hours per year when there is a lack of resources to cover the demand needs, within a sufficient transmission grid operational security limit. A more detailed presentation of the relations between average, P50, and P95 values is found in the following diagram.

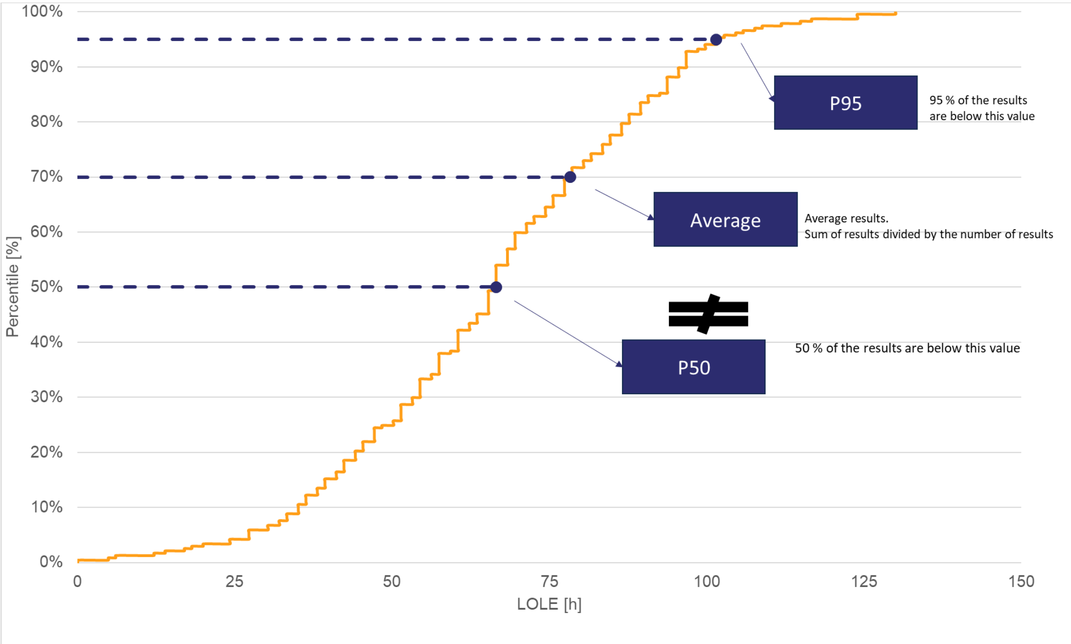

Figure 39 Illustrative example of the relation between average, P50, and P95 values.

- **P95/P50 Energy Not Served (P95/P50 ENS).** While ENS in a given geographical zone for a given period is the energy that is not supplied during a single Monte Carlo sample/simulation year due to the demand in the zone exceeding the combination of available resource capacity and electricity imports, P95/P50 ENS are ENS in more or less severe operational conditions.
  - P95: ENS that happens once every 20 years.
  - P50: ENS that happens once every 2 years.
- **Expected Energy Not Served (EENS)** in a given geographical zone for a given period, is the expected (average) value of energy not to be supplied due to a lack of resources, while complying with transmission grid operational security limits.
- **Relative EENS:** is a more suitable indicator to compare adequacy across geographical scope as it represents the percentage of annual demand which is expected to be not supplied.
- **Dump Energy:** or RES curtailment, in a given geographical zone for a given period, is the energy generated in excess that cannot be balanced, for instance when the load is low and the in-feed from renewables is high.
- **The Capacity Margin** for a given geographical zone for a given point in time is the difference between the available and engaged TPP capacity, as presented in the following diagram. These values point to the excess capacity in the system.

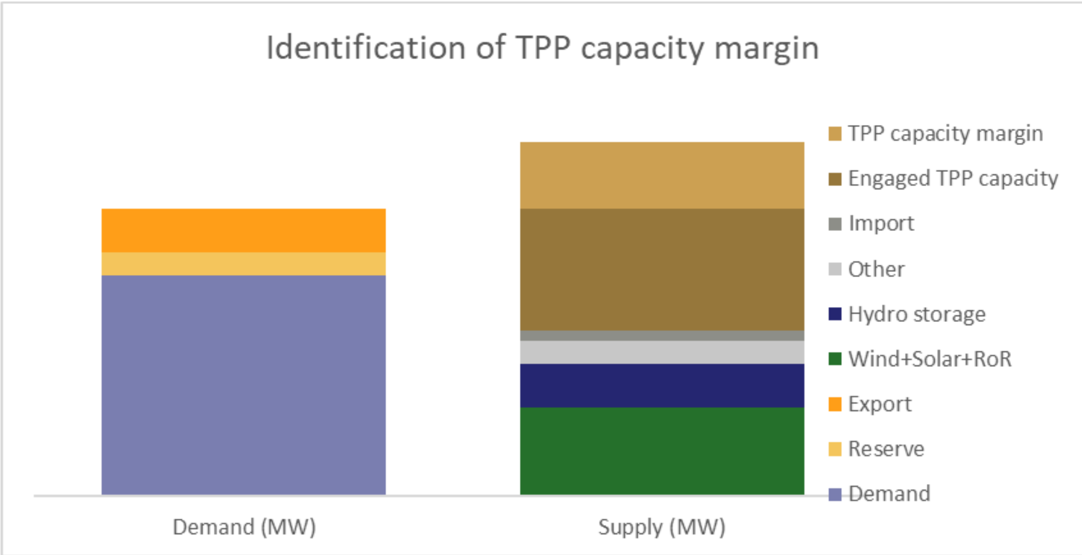

Figure 40 Illustrative example of TPP capacity margin identification.

Presentation of the adequacy indicators also includes the following:

1. The seasonal spatial screening gives a general indication of the adequacy risks for the coming season in the Med-TSO region. A relative EENS indicator is used, as illustrated in Figure 41
2. The temporal screening gives the indication when adequacy risks are the highest.

   Temporal risk screening is supported by the chart of daily LOLE and EENS at the country level, as illustrated in Figure 41. This would allow the detection of which weeks are most at risk.

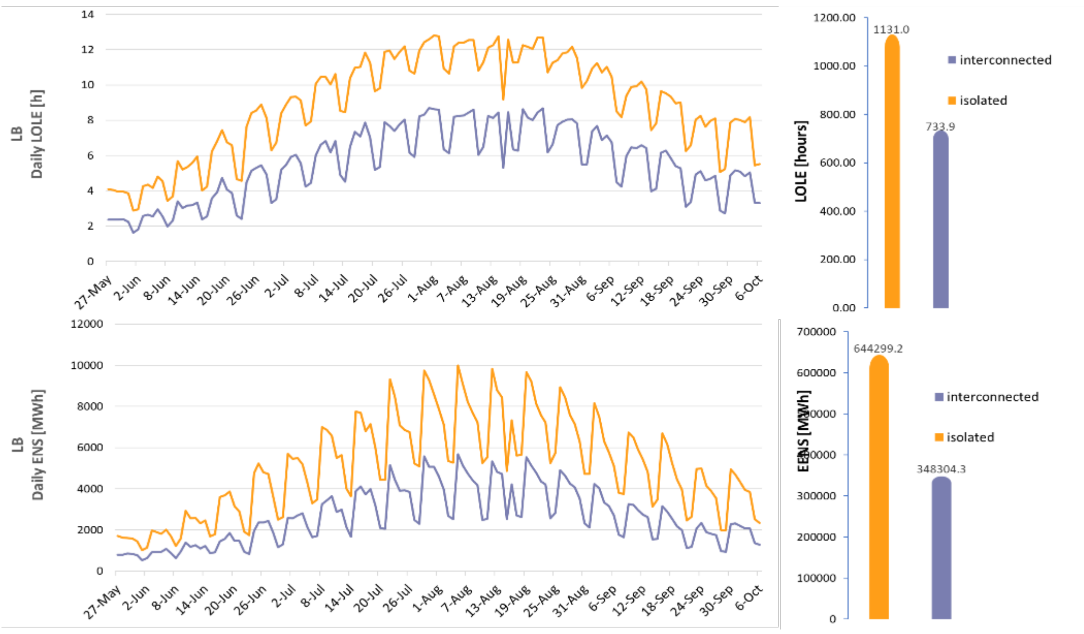

Figure 41 Illustrative example of average daily LOLE and EENS.

The available thermal capacities and thermal capacity margins are analysed and presented on both a daily and minimum hourly basis across all Monte Carlo (MC) simulation years. These analyses provide insights into periods of excess thermal capacity when no adequacy risks are present, as well as the specific weeks where adequacy risks are at a maximum.

Both the average and minimum daily values, as well as the minimum hourly values, are examined for all simulated MC years, as illustrated in the following figures. These figures offer a detailed breakdown, allowing for a clearer understanding of the trends in thermal capacity availability and the timing of adequacy risks.

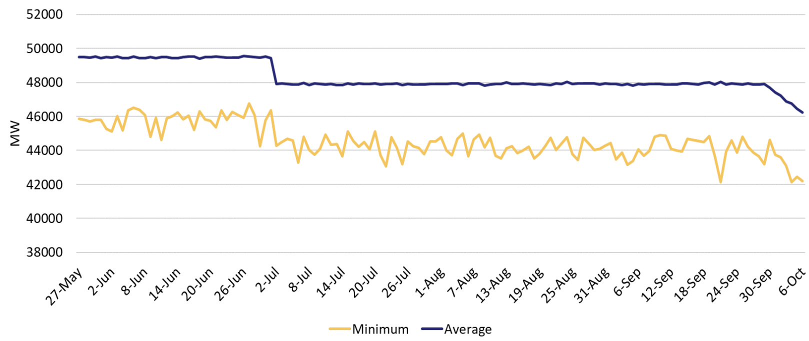

Figure 42 Illustrative example of available TPP capacity.

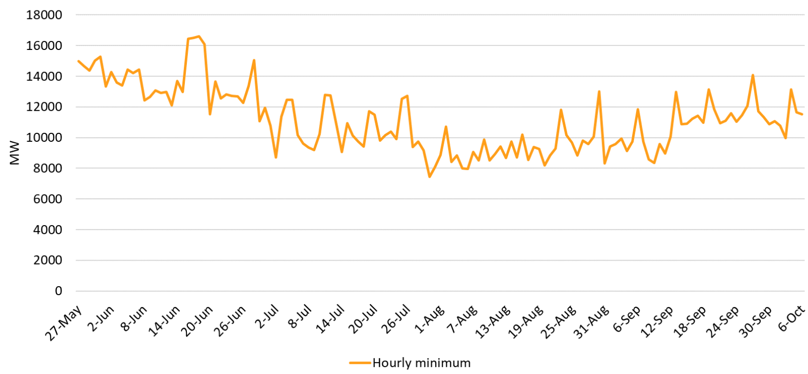

Figure 43 Minimum hourly TPP margin on each day of the analysed period.

6.1.3 Data collection and database preparation

This process included a collection of all relevant data and information necessary to model the power systems of Med-TSO countries. Where data was missing, standard values have been used and appropriate assumptions made, all based on publicly available data from relevant sources such as national network development plans and annual reports, Med-TSO publications[6], TYNDP 2020/2022, ERAA 2021, and any other relevant documents from the ENTSO-E website.

[6] https://Med-TSO.org/en/adequacystudies/

As an additional quality assurance, all provided data have been analysed and sanity checks conducted. In the case of suspicious data (i.e., technical data significantly deviating from relevant sources and literature), we discussed them with our members and updates/confirmations were provided.

Relevant data have been collected via standardised forms, designated for the compilation of data for different generation technologies, interconnections, and demand. The set of forms (PEMMDB V 3.5 Excel files) presents a database that will be regularly updated for each seasonal and mid-term adequacy assessment. Within the data collection, particular attention has been paid to the following parameters:

1. **Hourly demand per each market area/country**

   Hourly demand data for each market area (country) that is modelled has been provided by our members. These time series refer to different climatic conditions (mainly for the period 1982-2019 or similar, depending on the country). Demand data includes losses in the transmission network but does not include the self-consumption of generating units.

   Data about market-based demand-side responses are not provided and are not modelled.

   Additional demand during the charging of storage units has been obtained as the result of the simulations.

2. **Supply**

   Supply data includes the best estimates of available supply resources considering planned and unplanned outages. Supply resources are all available generation and storage units in the assessed Med-TSO systems, which are modelled at a unit-by-unit level. For some countries, schedules for the maintenance of thermal units have been provided by our members and these have been modelled as predetermined planned outages for corresponding units. Any additional maintenance activities have not been considered.

   When this information is not provided, planned outages are modelled for all units as random with a specified duration and period of occurrence. Unplanned outages are not known of in advance and to incorporate them, many random drawings are made, assuming standard rates of forced outage of generation assets.

   Supply-side technical constraints are also considered. These constraints include minimum and maximum generating capacities, possible capacity reduction, seasonal loss of efficiency, must-run obligation, reduced capacity due to the provision of FCR, etc.

Non-dispatchable weather-dependent generation (wind, solar or other renewable generation) is modelled by direct application of the time series. These time series are based on PECD version 3 but take into account the technologies used and zone splitting of each country.

Hydro generation is modelled using provided generation data, reservoir size and other relevant information, where available. Storage units are defined in terms of net discharge capacity, net charging capacity, storage capacity and cycle efficiency rate.

Reserve requirement values have been provided by our members, and the provision of the reserve is modelled by combining the reduction of available thermal capacity (usually due to the provision of FCR) and the increase in demand for the required balancing reserve (FRR or FCR+FRR). A difference between these two ways of reserve modelling lies in the fact that in the first type of reserve modelling, no energy requirements are involved and only a certain level of the capacity in TPPs is kept aside (and not engaged to cover the load). This does not generate any distortions in system operation results, but there may be some hours during the year in which full balancing requirements are not satisfied due to outages of TPPs (planned or forced).

In the second one, reserve capacity requirements (MW) are followed by energy requirements (MWh) which then make a distortion to all market or economic indicators (exchanges, price, etc,) calculated within the simulations. Due to artificial energy requirements in this case, this way of reserve modelling is not applicable for the systems with a large participation of hydropower plants.

Considering the structure of analysed power systems (practically no hydro generation), balancing reserve has been modelled as a negative balance (Export) with a fictitious node called rest of world (ROW) in all countries, bearing in mind that this approach is stricter and conservative in providing adequacy results that are on the safe side. Only in cases when a TSO provided capacity reduction at TPPs due to FCR provision, has the given reduction been applied (and only FRR requirements have been modelled as negative balance with ROW).
Considering the above-mentioned criteria, the data provided mainly included the following information:

- Installed capacities per technology.
- Technical characteristics of generating units, such as Pmin, Pmax.
- Expected maintenance schedule or other information for some countries.
- Must run obligations.
- Derating obligations.

- Expected generation for HPPs.
- Net discharge capacity, net charging capacity, storage capacity and cycle efficiency rate for storage units.
- Hourly wind and solar generation for several climatic years.
- Reserve requirements.

3. **Grid**

   Countries are modelled as copper plates, coupled via interconnectors described by NTCs values, provided by our members. Since NTC values related to HVAC interconnections already take into account n-1 security constraints, no additional outages are applied to them. In the case of HVDC interconnections, forced random outages are applied with a rate of 6% and an outage duration of one day (similar to what was applied in ERAA2021 by ENTSO-E).

Considering that the interconnection grid can play a key role in the country's security of supply and to assess that influence, two separate scenarios have been simulated:

- **Interconnected operation of the analysed countries.**
- **Isolated operation of the analysed countries.**

6.1.4 Number of MC years and results convergence

MC years have been constructed by combining climate-dependent variables (wind, solar and demand from 36 climatic years), available hydro time series and given/random outages. Since hydro data are not available for the same climatic years as for the wind, solar and demand, available years of hydro generation have been combined with other climate-dependent data and MC combinations have been developed as follows:

- Climate years (each of 36 years from PECD v4.2) are selected one by one.
- Each climate year is associated with random outage samples, i.e. randomly assigned, unplanned (and planned) outage patterns for thermal units.

The developed model was thoroughly tested concerning all relevant parameters of the generation portfolios of the different power generation technologies including RES, variable weather conditions and the status of the interconnections. The sufficient number of MC years to provide consistently good convergence of the main results has been determined as 684 (36 x 19). The number of MC years that ensures good convergence of results has been defined by assessing the coefficient of variation (α) of the EENS metric and its change.

$$\propto_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

Where EENSN is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}$, i=1…N and Var[EENSN] is the variance of the expectation estimate, i.e. $Var[EENS_N] = \frac{Var[ENS]}{N}$.

The evolution of convergence criteria is presented in the following figures.

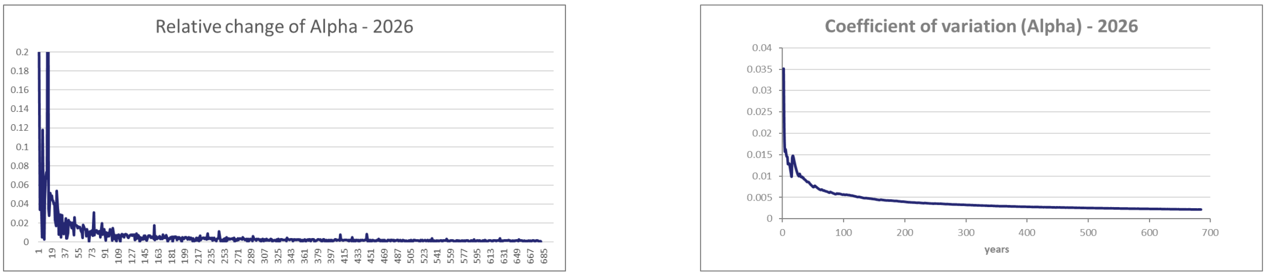

Figure 44 Evolution of convergence criteria for 684 MC years, simulations for the year 2026.

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