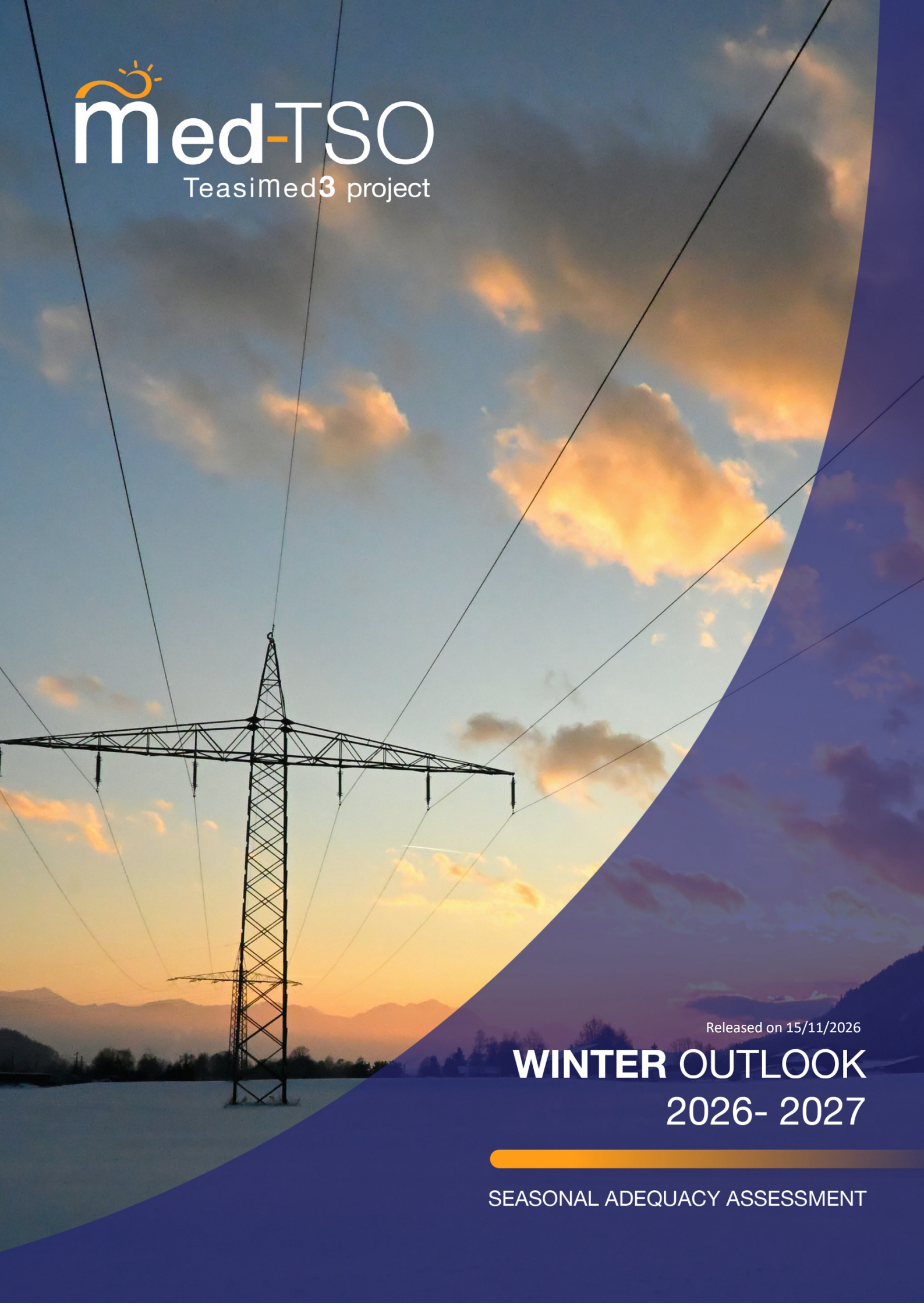


Released on 15/11/2026

WINTER OUTLOOK 2026- 2027

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 winter of 2026/2027. 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 Winter Outlook 2026/2027 Report provides important information about potential adequacy issues during the period from 23 November 2026 through to 4 April 2027 in six MED-TSO countries: Morocco, Tunisia, Libya, Egypt, Jordan, and Lebanon.

Data for Algeria is 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 each 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 importance of interconnections.

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

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

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.

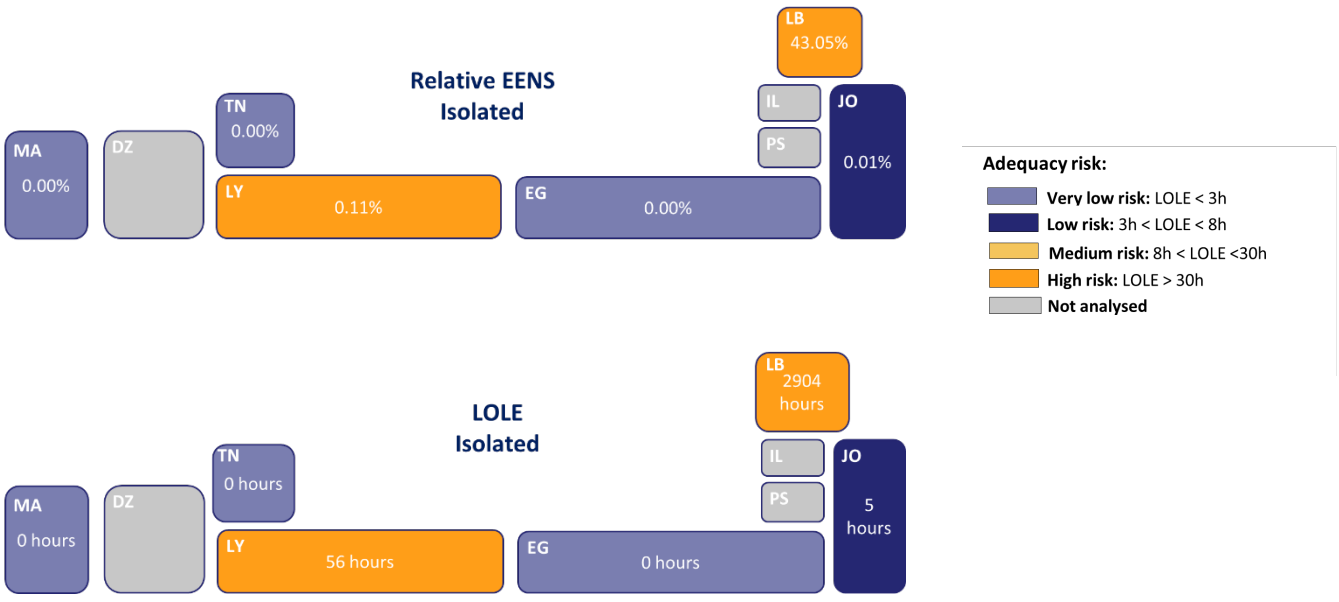


Figure 1 Relative EENS and LOLE for isolated system under normal operation mode (WO 2026/2027).

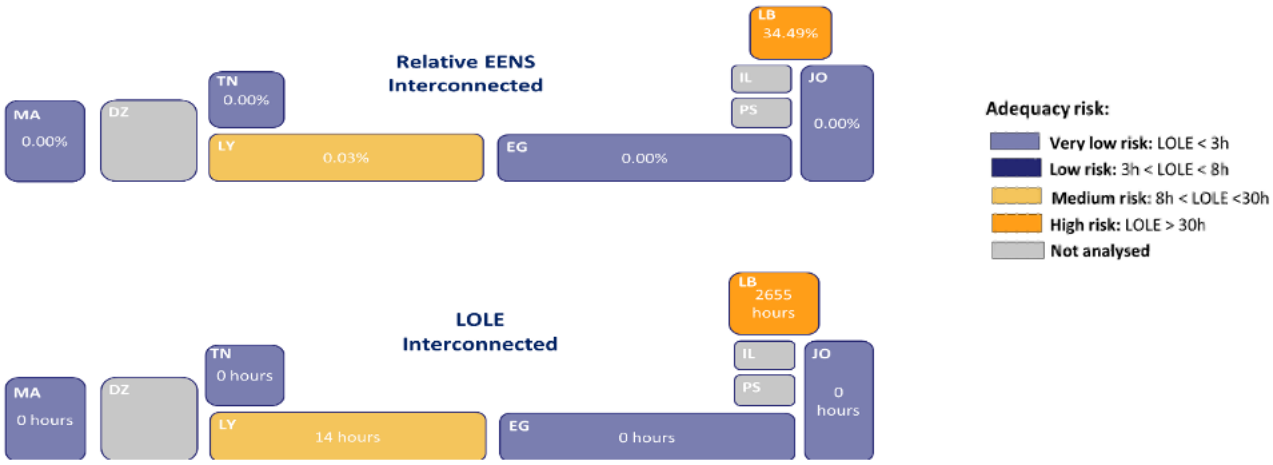


Figure 2 Relative EENS and LOLE for interconnected system under normal operation mode (WO 2026/2027).

Conclusion

The adequacy assessment of the regional power system for WO 2026/2027 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) is by far the most exposed country in the region in the isolated-mode assessment, with high LOLE and relative EENS values indicating persistent adequacy challenges during much of the winter season. These results reflect the limited availability of generation resources relative to demand. In practice, Lebanon's electricity supply also relies significantly on distributed solar PV (rooftops) and private self-generation. The results therefore highlight the vulnerability of the EDL power system and the potential value of cross-border interconnections in improving adequacy and reducing unserved energy.
- Libya (LY) falls into the high-risk band as well, though the gap to Lebanon is wide — its at-risk hours run to a considerable amount across the season rather than covering most of it. The margin between available thermal output and peak demand is still tighter here than almost anywhere else in the region.
- Tunisia (TN), on the other hand, carries essentially no adequacy risk this winter even in isolation — its generation margin is comfortable enough that going it alone poses no real threat to supply.
- Jordan (JO) sits in the low-risk band, with only a few at-risk hours expected under isolated operation.
- Morocco (MA) and Egypt (EG) both register negligible risk, confirming that each country's domestic generation alone is enough to cover projected winter demand.

In the interconnected mode -Figure 2-, the picture shifts for most countries, though not for all:

- Lebanon (LB) stays the clear outlier. Interconnection does bring real relief — fewer and less severe shortfalls than in isolation — but nowhere near enough to close the gap. Closing it will take domestic capacity investment alongside regional integration efforts.
- Libya (LY) moves out of the high-risk band once interconnected, though it lands in medium-risk territory rather than low — a meaningful improvement, not a full resolution. How much Libya leans on its links with Tunisia and Egypt to get there is worth keeping in view, particularly if either link were disrupted.
- Tunisia's (TN) adequacy risk remains negligible under interconnected operation, as its robust domestic supply position means that crossborder support is not essential to maintain adequacy this winter. This assessment covers the winter season only and should not be assumed to apply to summer.

- Jordan (JO) improves further still, moving from low to very low risk and confirming how effectively it can lean on regional exchange when needed.
- Morocco (MA) and Egypt (EG) hold at negligible risk under both operating modes, underscoring the strength of their domestic capacity and their potential to act as net exporters for the wider region.

Challenges in Libya

Libya's thermal fleet capacity is up 19% on the previous release, to roughly 9,300 MW, reflecting the commissioning of new thermal units alongside this release's fleet re-evaluation. The system remains entirely thermal and continues to face long-standing structural and technical difficulties that limit its reliability and resilience -- but the added capacity is a step in the right direction.

- Ageing infrastructure and limited transmission capacity still cap how much of the interconnection benefit Libya can actually capture.
- Imports from neighbouring systems remain essential to covering peak and stress-period demand.

Sustained improvements will require rehabilitation of the domestic transmission network, reinforcement of interconnections, and closer coordination between the electricity and gas sectors to ensure reliable fuel supply.

Libya’s adequacy position is particularly sensitive to the availability of individual thermal units. Relatively small changes in fleet availability can therefore materially affect the results between assessments, highlighting the importance of updating the fleet evaluation for each release.

Challenges in Lebanon

Lebanon's adequacy position remains critical. Interconnection helps at the margins, but even a hypothetical scenario of full interconnection and full generation availability would still leave meaningful risk on the table.

- Persistently high LOLE traces back to a simple shortfall: domestic generation capacity that doesn't come close to covering demand.
- Fuel and gas shortages, frequent outages, and an ageing asset base compound the problem operationally.
- Grid constraints and limited import capacity cap how much interconnection alone can do to close the gap.

Closing it sustainably would need meaningful investment on three fronts at once — domestic generation, fuel availability, and cross-border transmission capacity.

Interconnection can soften Lebanon's adequacy risk, but on its own it cannot resolve the underlying supply and fuel problems driving it.

2. What's New in This Release

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 Winter Outlook 2026/2027 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 Winter Outlook 2026/2027

This Winter Outlook 2026/2027 Report provides information regarding potential adequacy issues in six MED-TSO member states: Morocco, Libya, Tunisia, Egypt, Jordan, and Lebanon.

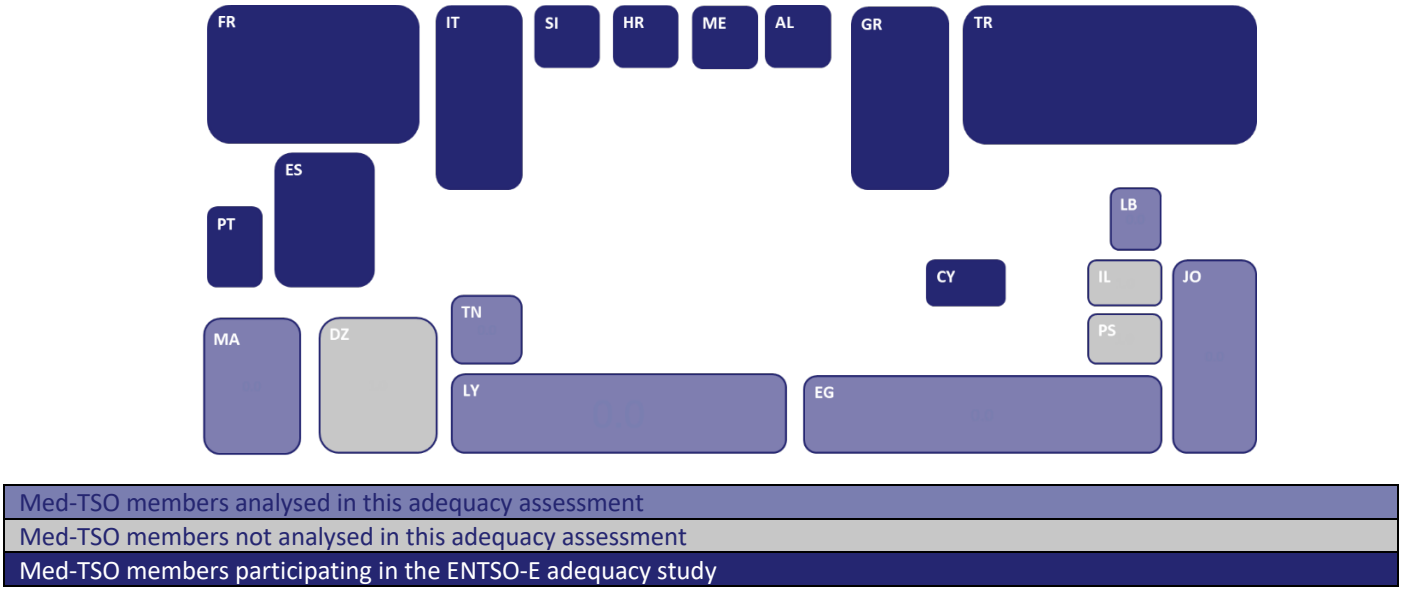


Figure 3 Med-TSO members and neighbouring countries (source: Med-TSO).

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 48, 2026 and the end of week 13, 2027, which constitutes the period between Monday 23 November 2026 and Sunday 4 April 2027. The overview is organized 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 48, 2026, through to week 13, 2027. 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 winter period.

Table 1 Expected consumption in the winter weeks – 2026/2027.

Weekly consumption based on average among 36 CY (GWh)		EG	JO	LB	LY	MA	TN
Total		75639	9214	8813	17840	17418	7903
Week	48	4150	481	460	829	948	418
Week	49	4112	482	463	862	944	421
Week	50	4090	489	469	891	943	427
Week	51	4086	502	478	918	944	430
Week	52	4100	511	489	937	943	442
Week	1	4184	532	507	1122	978	450
Week	2	4193	532	513	1116	966	457
Week	3	4192	534	515	1107	990	458
Week	4	4205	537	517	1100	989	456
Week	5	4216	538	515	1089	987	457
Week	6	4230	537	524	1084	977	450
Week	7	4238	524	511	1054	973	448
Week	8	4242	516	497	1014	972	442
Week	9	4270	504	484	980	977	438
Week	10	4138	486	477	962	926	408
Week	11	4262	505	471	934	964	436
Week	12	4340	503	466	919	994	432
Week	13	4390	500	457	921	1003	433

High Value
Low Value

Egypt's electricity consumption is substantially higher than that of the other five countries and is therefore plotted against the right-hand y-axis in the figure below to ensure readability.

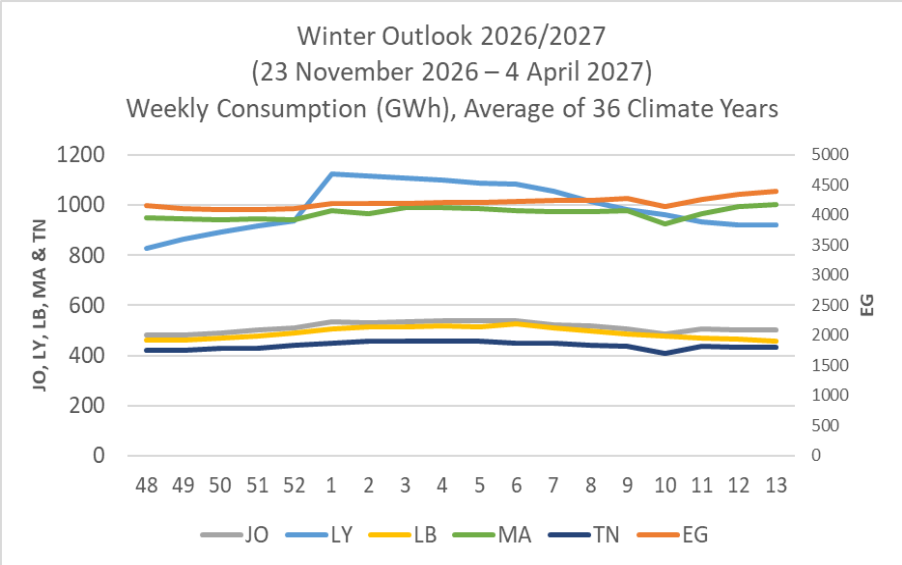


Figure 4 Expected weekly consumption per country in the analyzed season.

Jordan, Lebanon, and Tunisia cluster at the low end of weekly consumption among the six countries, with Libya and Morocco sitting a tier above them. Egypt's electricity demand substantially exceeds that of the other five countries, reaching nearly ten times the lowest demand level in the group.

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.

Table 2 Maximum weekly peak loads in winter weeks 2026/2027.

Peak load, based on maximum among 36 CY (MW)		EG	JO	LB	LY	MA	TN
Maximum		32905	5013	4766	9374	7470	3916
Week	48	31146	4233	3667	6941	7224	3498
Week	49	31960	4145	3673	7259	7199	3539
Week	50	31039	4221	3909	7484	7194	3626
Week	51	30622	4279	3947	8186	7214	3791
Week	52	30987	4445	4093	7870	7196	3897
Week	1	30801	4602	4286	9374	7348	3835
Week	2	31102	4878	4518	8889	7411	3892
Week	3	30884	4827	4442	8747	7394	3916
Week	4	30637	4575	4208	8805	7313	3814
Week	5	30774	4827	4491	8957	7346	3869
Week	6	31175	5013	4766	9006	7417	3718
Week	7	31161	4635	4596	8354	7374	3613
Week	8	30717	4997	4691	7810	7434	3480
Week	9	30769	4486	4322	7534	7470	3426
Week	10	30628	4345	3908	7550	7319	3361
Week	11	30594	4349	3893	7124	7265	3451
Week	12	32098	4375	3867	7084	7195	3466
Week	13	32905	4346	3691	7208	7256	3390

High Value
Low Value

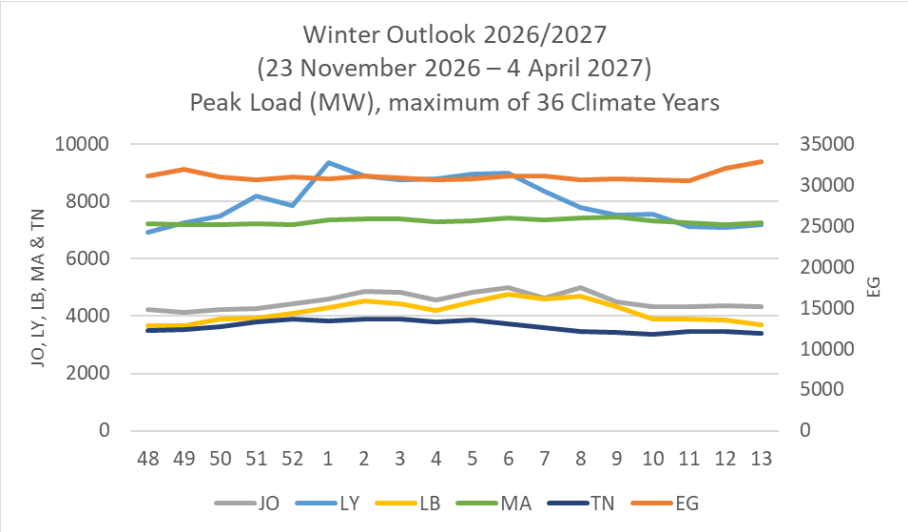


Figure 5 Maximum weekly peak loads per country in the analysed season.

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 installed generation and storage capacities expected to be available during winter 2026/2027. Total installed generation capacity in the region is projected to reach approximately 103.5 GW, of which nearly 79 GW (approximately 76%) corresponds to thermal units.

Changes in installed capacity relative to the Winter Outlook 2025/2026 are highlighted using two colours: green indicates increases, while orange indicates decreases.

Battery storage capacity has increased in several countries. Egypt's grid-scale battery capacity has reached 610 MW, representing a huge increase compared with the previous release, while Jordan has introduced its first battery storage capacity, totaling 12.5 MW. In contrast, Morocco's reported battery capacity has been revised to 275 MW. The commissioning timeline assumed in the previous release has since been updated, with this capacity now expected to enter service during the WO 2026/2027 period. Battery discharge is scheduled according to system needs, particularly during periods of peak demand.

Renewable capacity has also increased across several countries. Wind capacity has expanded in Morocco and Tunisia, while solar PV capacity has grown considerably in Egypt, Jordan, Morocco and Tunisia. Egypt has also recorded an increase in installed hydropower capacity. Lebanon is the only country reporting no capacity growth across any renewable generation or storage category compared with the previous release.

Table 3 Total expected available installed capacities (MW) per technology during winter period from W48 to W13, 2027.

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 (98%▲)	7%			140 (No Change)	0%	2981 (5%▲)	5%	610 (307%▲)	1%			50407 (0%▼)	82%	**61615**
JO	621 (No Change)	8%	2473 (6%▲)	31%							12.5 (New Capacity▲)				4813.9 (1%▲)	61%	**7920**
LB			1470 (No Change)	38%					285 (No Change)	7%					2153 (-13%▼)	55%	**3908**
LY			0 (-100%▼)	0%											9302.26 (19%▲)	100%	**9302**
MA	3497.4 (45%▲)	24%	1033.8 (98%▲)	7%	540 (No Change)	4%			1306 (No Change)	9%	275 (-31%▼)	2%	790 (No Change)	5%	6940.7 (8%▲)	48%	**14383**
TN	232 (1%▲)	4%	1030 (43%▲)	16%											5117 (No Change)	80%	**6379**
TOTAL	**7387**	**7%**	**10448**	**10%**	**540**	**1%**	**140**	**0%**	**4572**	**4%**	**898**	**1%**	**790**	**1%**	**78734**	**76%**	**103508**

	Installed Capacity [GW]	Peak Load [GW]
EG	61.6	32.9
JO	7.9	5
LB	3.9	4.77
LY	9.3	9.4
MA	14.4	7.5
TN	6.4	3.9

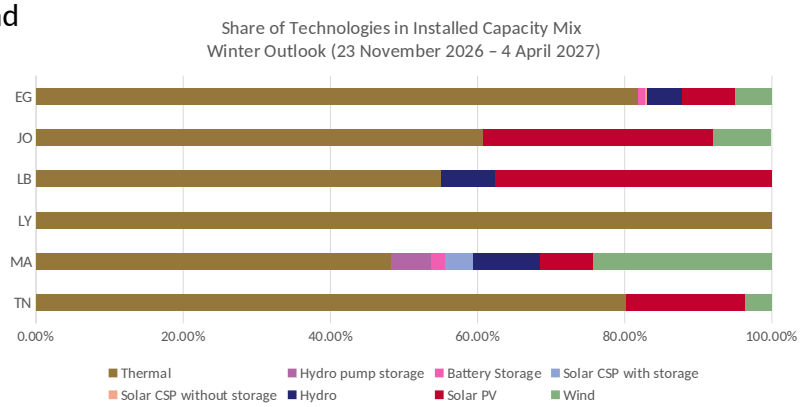


Figure 6 Available Installed capacity mix and peak load in winter period.

As shown in Table 3 Libya's generation mix remains dependent on thermal units. Installed thermal capacity has increased by approximately 19% compared with the previous release, reaching around 9,300 MW. This increase reflects the commissioning of new units alongside an updated assessment of the existing fleet, strengthening the country's domestic generation capacity. The availability and operational reliability of these units remain key determinants of Libya's adequacy position during the winter period. The solar PV capacity of Libya included in the previous release has been removed following a revision of the data provided, and no solar PV capacity is assumed for this winter.

Hydropower shows up in two forms and two countries. Egypt's conventional hydro capacity is up 5% to just under 3,000 MW, and Morocco combines 1,306 MW of conventional hydro with a separate 790 MW pumped-storage plant (PSHPP) -- both unchanged from the previous release.

Wind and solar together make up the largest share of installed capacity in Jordan, Lebanon, and Morocco -- all above a third of total capacity, topping out at 39% in Jordan's case. In Morocco, 540 MW of that solar capacity specifically is CSP 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 WO 2026/2027.

	2026		
Country	Wind CF	Solar CF	Solar CSP
EG	54.4%	26.2%	24.4%
JO	34%	26.5%	
LB	-	18%	
LY	-	-	
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
MA00	yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes
TN00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes

- For the planned maintenance, only TN, MA & JO provided maintenance schedule as for the rest of TSOs default parameters is applied for the rest of the courtiers, they follow the table below for allowing planned maintenance activities.

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*

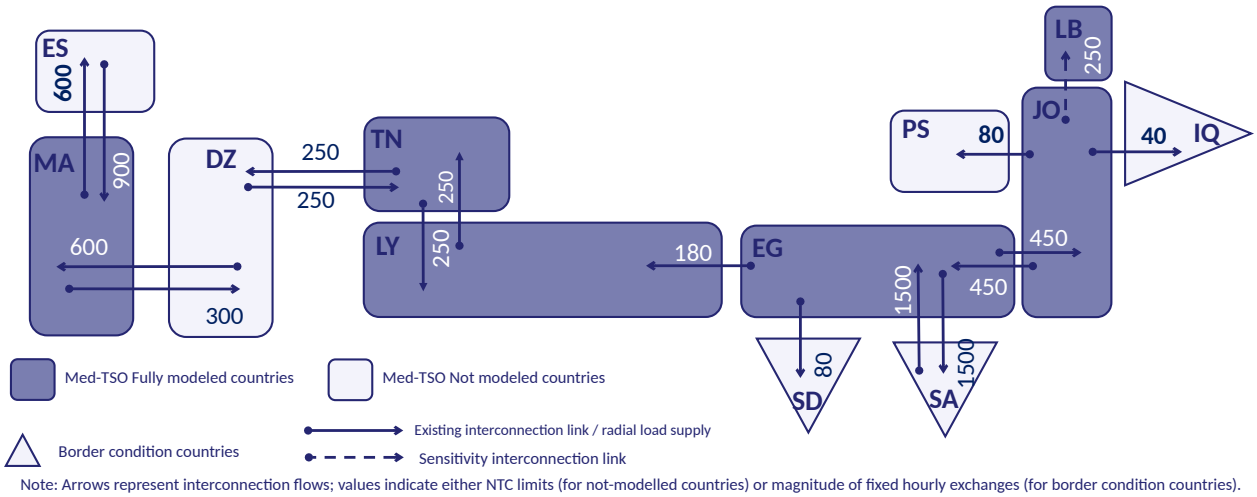
Cross-border transfer capabilities are represented by the summarised Net Transfer Capacity (NTC) values. Throughout the calculation period, these capacities are assumed to be used solely to address adequacy shortfalls. NTC defines the maximum exchange between two interconnected areas consistent with the applicable operational security standards, including the N-1 criterion, under which the system must remain within acceptable operating limits following the loss of a single network element. Under exceptional circumstances, transfers may exceed the established NTC to meet urgent demand, subject to operational decisions and the acceptance of reduced security margins.

The Antares model covers the six Med-TSO member countries assessed in this study, incorporating detailed generation capacities and electricity demand. Cross-border connections are represented through NTC limits, while internal transmission networks are not explicitly modelled. Exchanges with countries outside the modelled region are represented using hourly profiles provided by the respective members. Algeria is assumed to have no adequacy shortfalls and to be capable of supplying neighbouring countries when they face adequacy risks.

A specific limitation concerns the Egypt–Jordan (EG–JO) interconnection, which comprises a single circuit. An outage of this circuit would therefore interrupt all direct electricity exchanges between the two countries. Unlike interconnections with multiple circuits, this link provides no remaining transfer capacity following its loss. Consequently, adequacy results that depend on EG–JO exchanges should be interpreted considering this absence of redundancy. Compliance with the N-1 criterion at system level would require the affected systems to accommodate the loss of the interconnection.

For Lebanon, a sensitivity analysis considers a hypothetical connection with Jordan through Syria, allowing imports of up to 250 MW. This assumption is used to assess the potential contribution of cross-border support to Lebanon's adequacy.

A summary of the interconnection capacities and given exchanges is presented in the following figure.



Note: Arrows represent interconnection flows; values indicate either NTC limits (for not-modelled countries) or magnitude of fixed hourly exchanges (for border condition countries).

Figure 7 Net transfer capacity during WO 2026/2027.

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 modeled 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		WO 2026_2027
EG	FCR+FRR [MW]	1200
JO	FCR+FRR [MW]	210
LB	FCR+FRR [MW]	120
LY	FCR+FRR [MW]	250
MA	FCR+FRR [MW] [2]	700
TN	FCR+FRR [MW]	220

[2] 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.

Under a purely isolated scenario (Figure 8) focused on the winter season, meaningful adequacy risk is really confined to Lebanon, with Libya a distant second; Jordan, Tunisia, Morocco and Egypt all sit at low-to-negligible risk.

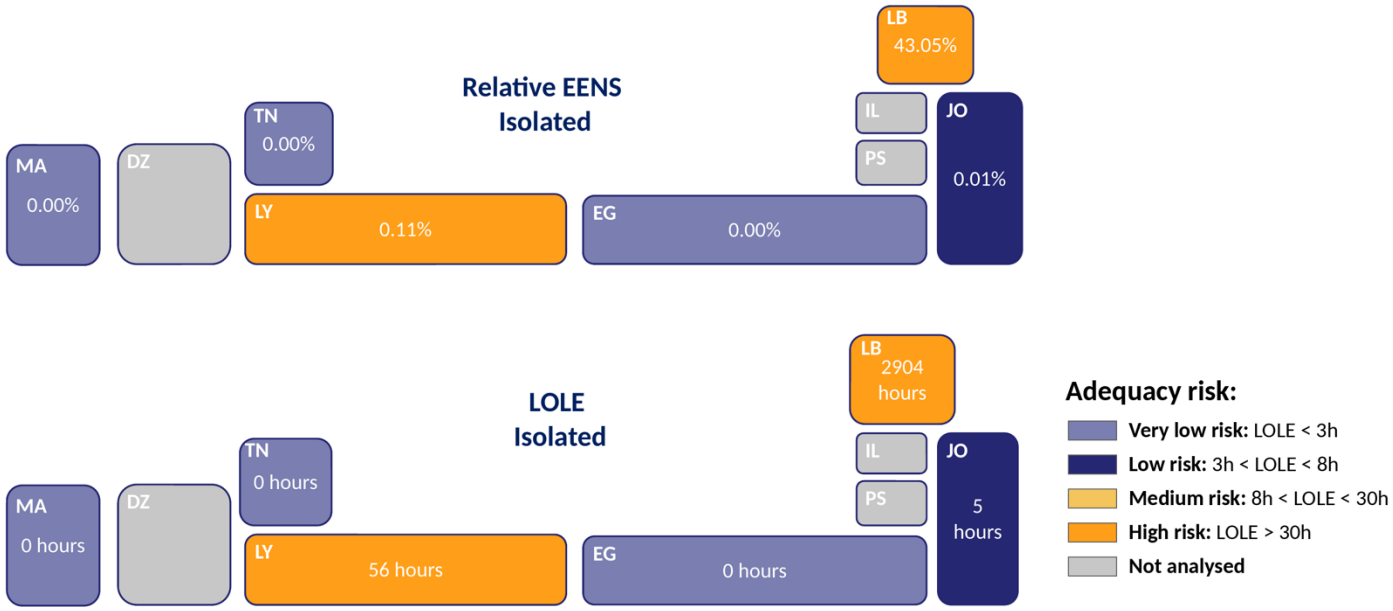
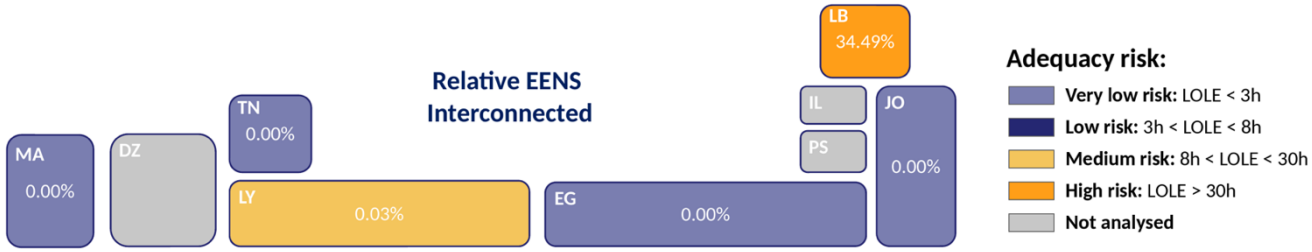


Figure 8 Relative EENS and LOLE for isolated system under normal operation mode (WO 2026/2027).

Once interconnections and the exchanges needed to cover adequacy shortfalls are factored in, risk drops to negligible for Jordan and Tunisia and to a medium level for Libya. Lebanon is the exception — even under this more relaxed operating mode, its risk remains unacceptably high.



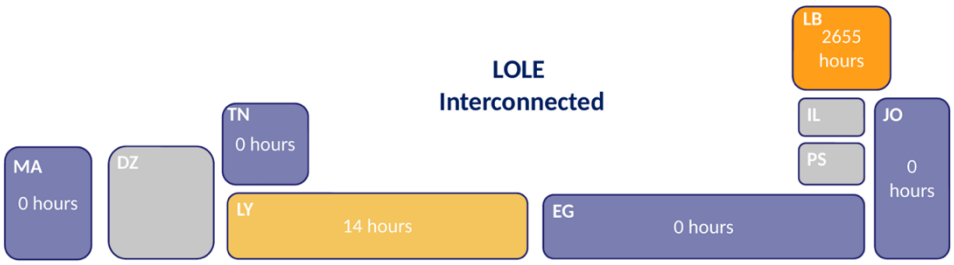


Figure 9 Relative EENS and LOLE for Interconnected system under normal operation mode (WO 20262027).

Table 8 Seasonal EENS for interconnected and isolated scenarios.

Country	Isolated EENS	Interconnected EENS	Isolated LOLE	Interconnected LOLE
DZ	0 MWh	0 MWh	0	0
	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
EG	0 MWh	0 MWh	0	0
	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	788 MWh	32 MWh	4.76	0.27
	50th percentile 102 MWh	50th percentile 0 MWh	50th percentile LOLD: 2 hours	50th percentile LOLD: 0 hours
	95th percentile 4799 MWh	95th percentile 194 MWh	95th percentile LOLD: 25 hours	95th percentile LOLD: 2 hours
MA	8 MWh	0 MWh	0.02	0
	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	28 MWh	0 MWh	0,27	0
	50th percentile 0 MWh	50th percentile 0 MWh	50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 200 MWh	95th percentile 0 MWh	95th percentile LOLD: 2 hours	95th percentile LOLD: 0 hours

LY	19676 MWh	4571 MWh	56.04	14.28
	50th percentile 13482 MWh	50th percentile 1526 MWh	50th percentile LOLD: 48 hours	50th percentile LOLD: 9 hours
	95th percentile 55968 MWh	95th percentile 20401 MWh	95th percentile LOLD: 145 hours	95th percentile LOLD: 43 hours
LB	3794142 MWH	3039949 MWH	2903.9	2655.32
	50th percentile 3768970 MWh	50th percentile 3012970 MWh	50th percentile LOLD: 2913 hours	50th percentile LOLD: 2659 hours
	95th percentile 4327310 MWh	95th percentile 3573870 MWh	95th percentile LOLD: 2998 hours	95th percentile LOLD: 2812 hours

Adequacy risk:
- **Very 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

Jordan's risk under isolation sits on the low side: around 5 hours of LOLE and roughly 788 MWh of EENS across the season. Interconnection pushes both figures down further still — LOLE close to zero, EENS around 31 MWh — which underscores how effectively regional exchange covers the modest gap Jordan starts with.

Under the P95 sensitivity scenario, isolated-mode LOLE reaches roughly 25 hours with EENS around 4,799 MWh -- meaningfully higher than the normal case, but still a fraction of what less resilient countries in the region face. Interconnected operation brings both down further, to about 2 hours of LOLE and 194 MWh of EENS.

These findings highlight the crucial role of interconnections in enhancing Jordan's adequacy under extreme conditions.

Tunisia

Tunisia's picture under normal conditions is reassuring: isolated LOLE stays under a third of an hour for the whole season, with EENS around 30 MWh. Interconnected operation pushes both effectively to zero, confirming that Tunisia's own generation fleet is enough to meet winter demand without leaning on its neighbours.

Under the P95 sensitivity scenario, isolated-mode LOLE reaches about 2 hours with EENS around 200 MWh -- a mild increase over the already-low normal case. Interconnected operation brings both effectively to zero, confirming that Tunisia's position holds up even under adverse conditions.

In short, Tunisia enters the winter with a comfortable adequacy position on its own, and that holds even under the more severe P95 conditions -- interconnection isn't doing much heavy lifting here either way.

Libya

In isolated operation, Libya falls within the high-risk category defined by the chart, with seasonal LOLE of approximately 56 hours and EENS of 19,676 MWh (≈19.7 GWh).

Interconnected operation reduces LOLE to approximately 14 hours and EENS to 4,571 MWh, placing Libya in the medium-risk category. Cross-border support therefore substantially improves adequacy but does not eliminate the risk. The limited domestic thermal capacity margin shown in Figure 27 warrants continued monitoring, as imports remain an important contributor to adequacy.

Under the P95 sensitivity scenario, isolated-operation LOLE rises to approximately 145 hours, while EENS reaches 55,968 MWh (≈56 GWh). This represents a substantial deterioration relative to the base case, although the values remain considerably below those of Lebanon. Interconnection continues to provide significant support under these conditions, reducing LOLE to approximately 43 hours and EENS to 20,401 MWh.

Lebanon

Lebanon exhibits the most severe adequacy shortfalls among the countries assessed. In isolated operation, LOLE reaches approximately 2,904 hours, with EENS of 3,794,142 MWh (≈3.8 TWh). These values indicate a persistent supply deficit affecting most of the winter assessment period, rather than occasional periods of scarcity.

Interconnected operation provides some relief, reducing LOLE to approximately 2,655 hours and EENS to 3,039,949 MWh (≈3.0 TWh). However, the remaining shortfall is substantial, demonstrating that the assumed cross-border support is insufficient to address Lebanon's underlying adequacy deficit.

Under the P95 sensitivity scenario, the adequacy position deteriorates further. In isolated operation, LOLE increases to approximately 2,998 hours and EENS reaches 4,327,310 MWh (≈4.3 TWh). Even with interconnection, LOLE remains at approximately 2,812 hours, with EENS of 3,573,870 MWh (≈3.6 TWh). These results reinforce the structural and persistent nature of Lebanon's supply deficit.

Egypt and Morocco

Egypt records zero LOLE and EENS across all scenarios presented in **Table 8** including isolated and interconnected operation and the P50 and P95 sensitivity results. Morocco also demonstrates a strong adequacy position, with negligible risk in isolated operation—8 MWh of EENS and 0.02 hours of LOLE—which is eliminated under interconnected operation. These findings indicate robust domestic supply positions and suggest that both countries could contribute to regional adequacy, subject to available generation and cross-border transfer capacity.

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 winter. 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	0	250	0	250
EG00	JO00	5	450	0	450
EG00	LY00	10	180	0	0
EG00	SD00	242	80	0	0
ES00	MA00	0	900	0	600
JO00	PS00	242	80	0	0
LY00	TN00	0	250	5	250
JO00	LB00	754	250	0	0
JO00	IQ00	121	40	0	0
EG00	SA00	0	1500	0	1500

Egypt exports approximately 5 GWh to Jordan for adequacy purposes over the season, exceeding Jordan's isolated-operation shortfall of less than 800 MWh reported in **Table 8**. Egypt also supplies approximately 10 GWh to Libya, while Tunisia contributes a further 5 GWh. Together, these exchanges account for nearly the entire 15 GWh reduction in Libya's EENS under interconnected operation shown in **Table 8**. Egypt and Jordan also have fixed hourly export commitments to Sudan, Palestine and Iraq, represented as boundary conditions in the model.

Tunisia requires no adequacy-related exchanges with Algeria during the assessment period. Table 9 reports zero exchanges in both directions along this corridor, consistent with Tunisia's negligible isolated-operation risk in **Table 8**, with seasonal LOLE of approximately 0.25 hours and EENS of 28 MWh. The results therefore indicate no adequacy-driven need for transfers exceeding the assumed NTC on this corridor, unlike the operating conditions reportedly experienced in previous periods.

Lebanon's improvement under interconnected operation is attributable almost entirely to the assumed Jordan–Lebanon connection. With an NTC of 250 MW, this corridor supplies approximately 754 GWh over the season, indicating utilisation close to its full transfer capacity for much of the winter. These imports account for nearly all of Lebanon's adequacy improvement: EENS decreases by approximately 20%, from 3.79 TWh to 3.04 TWh, while LOLE declines by approximately 9%, from 2,904 to 2,655 hours. Nevertheless, interconnection addresses only part of Lebanon's substantial supply deficit, and additional measures would be required to reduce the remaining shortfall.

5. Adequacy Situation at Country Level

5.1. Egypt

DEMAND

In winter, Egypt's weekly demand Figure 10, sits between roughly 4,086 GWh
and 4,390 GWh, with P95 peak hourly demand spanning about 30.6 to 32.9 GW. Weekly demand here reflects the average across all 36 climatic years, while the peak figures are the P95 weekly maximum across that same set.

The figure below shows demand building gradually over the season, with the highest levels reached in its closing weeks (around week 13, late March) rather than at any single sharp peak — the rest of the winter stays comparatively even. Hourly demand varies by only around 7-8% across the season, a noticeably narrower spread than summer typically brings.

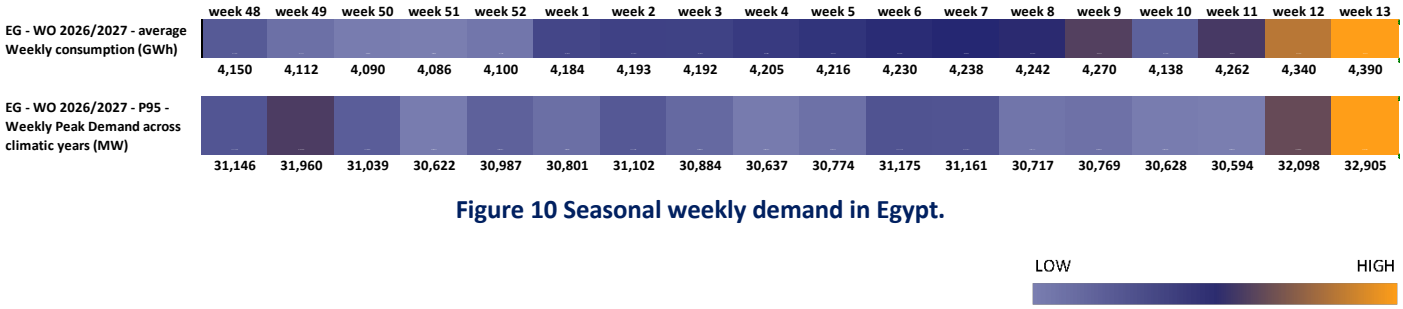


Figure 10 Seasonal weekly demand in Egypt.

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.

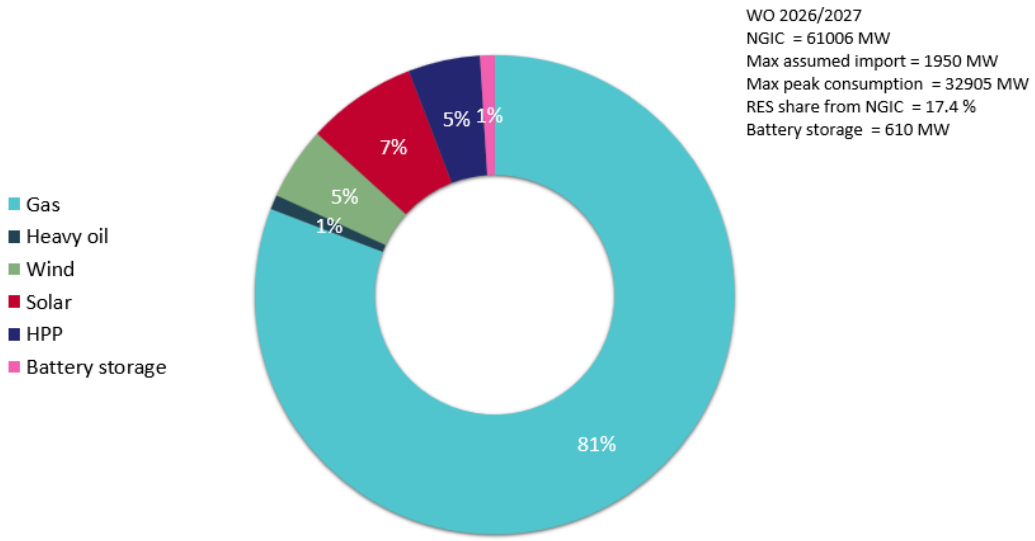


Figure 11 Available installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Egypt

Figure 12. traces the average daily available TPP capacity after forced outages, using the average across all simulated MC years (identical for both isolated and interconnected modes). That average holds close to 42 GW for essentially the whole winter, while the minimum daily figure — the lowest value across all MC years, once derating and outages are factored in — moves between roughly 35 GW and 38.5 GW.

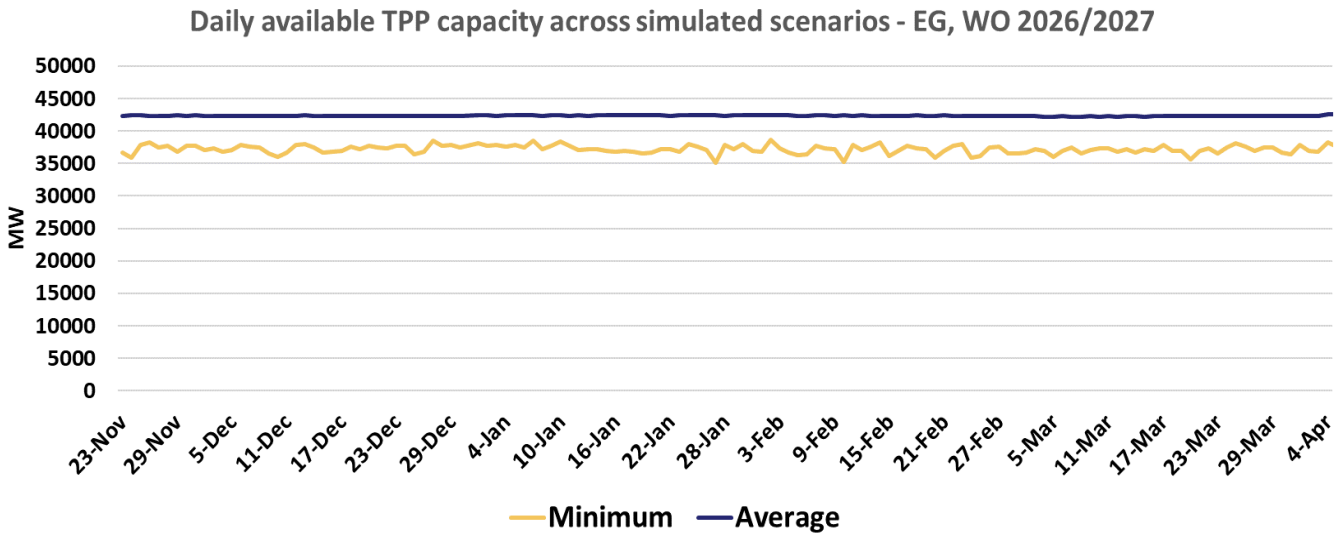


Figure 12 Average and minimum TPP available capacity among all simulated MC years in Egypt.

Figure 13. plots the minimum hourly TPP margin across all simulated years — the gap between available and activated capacity — for the winter period running 23 November 2026 to 4 April 2027. This margin shifts throughout the season but never comes close to zero, staying broadly within 6.8-12.5 GW. The tightest points fall around late November, late January and late March; the widest — above 12 GW — turn up near early January, early February and mid-March.

Because the margin stays positive throughout, Egypt faces no thermal adequacy shortfall over winter 2026/2027. Those consistently comfortable margins point to strong thermal reserves and real export potential that could support neighbouring systems under strain.

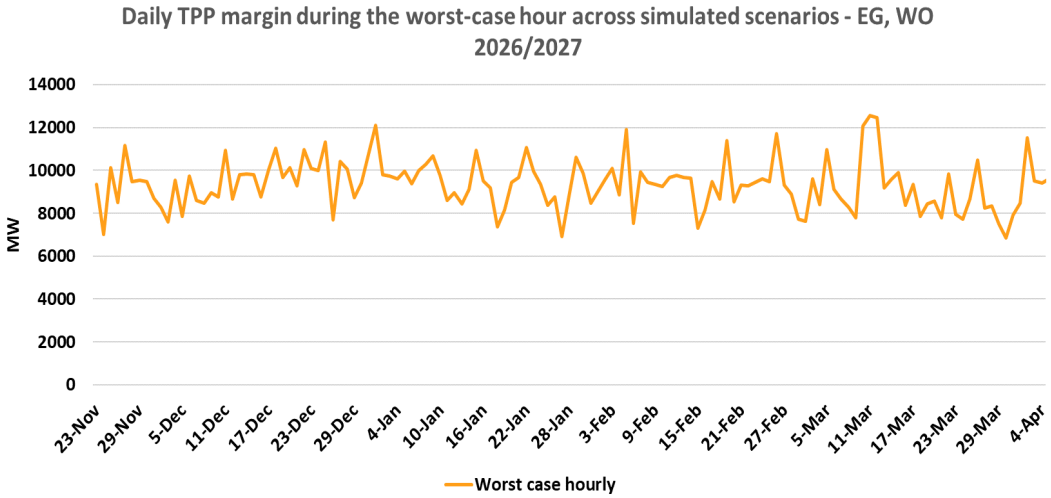


Figure 13 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Egypt.

ADEQUACY ASSESSMENT

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

5.2. Jordan

DEMAND

Jordan's winter weekly demand Figure 14, runs from about 481 GWh to 538 GWh — a swing of roughly 12% — while P95 peak hourly demand ranges more widely, from 4,145 MW to 5,013 MW, close to a 21% spread. As elsewhere, weekly demand is the 36-year average and the peak figures reflect the P95 weekly maximum across that same set of years.

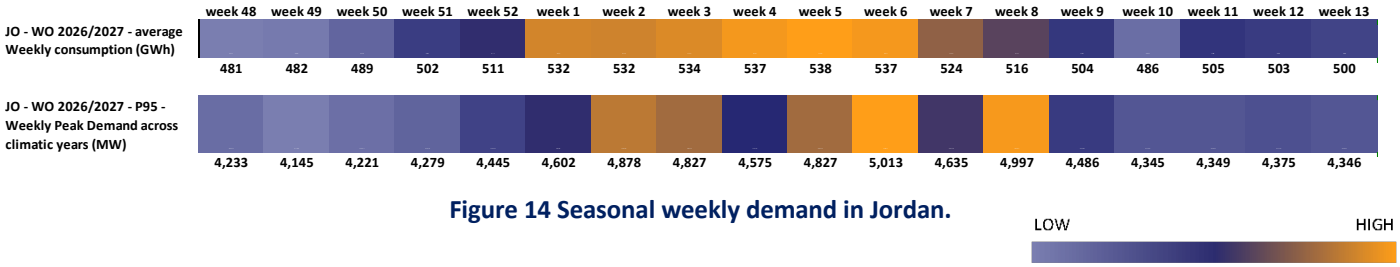


Figure 14 Seasonal weekly demand in Jordan.

SUPPLY AND NETWORK OVERVIEW

Natural gas still dominates Jordan's generation mix, but renewables have carved out a real presence: solar alone accounts for nearly a third of installed capacity, with wind and oil shale filling smaller roles. Altogether RES makes up 39.1% of NGIC — among the highest shares in the region — a reflection of how seriously Jordan has pursued 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.

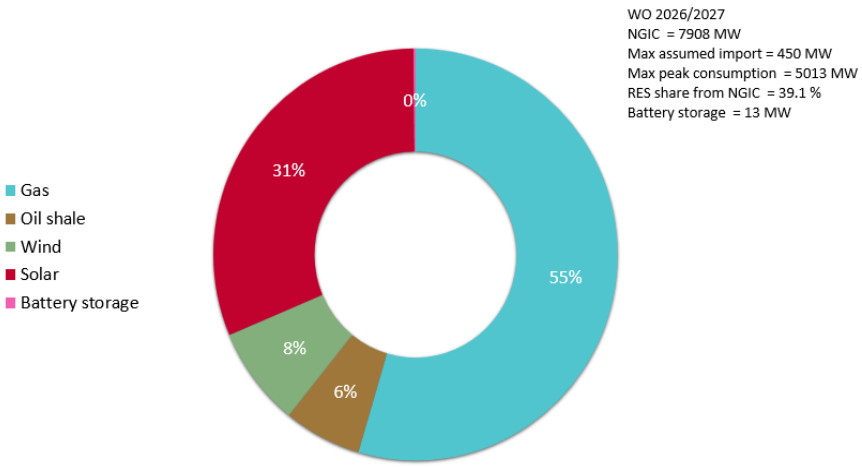


Figure 15 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Jordan.

Figure 16. shows average daily available TPP capacity after derating and outages, again identical across both operating modes. It opens the season around 4,300 MW and climbs to roughly 4,600-4,700 MW once January begins, tracking the maintenance schedule; the minimum daily figure across all MC years ranges from about 3,500 MW to 4,100 MW.

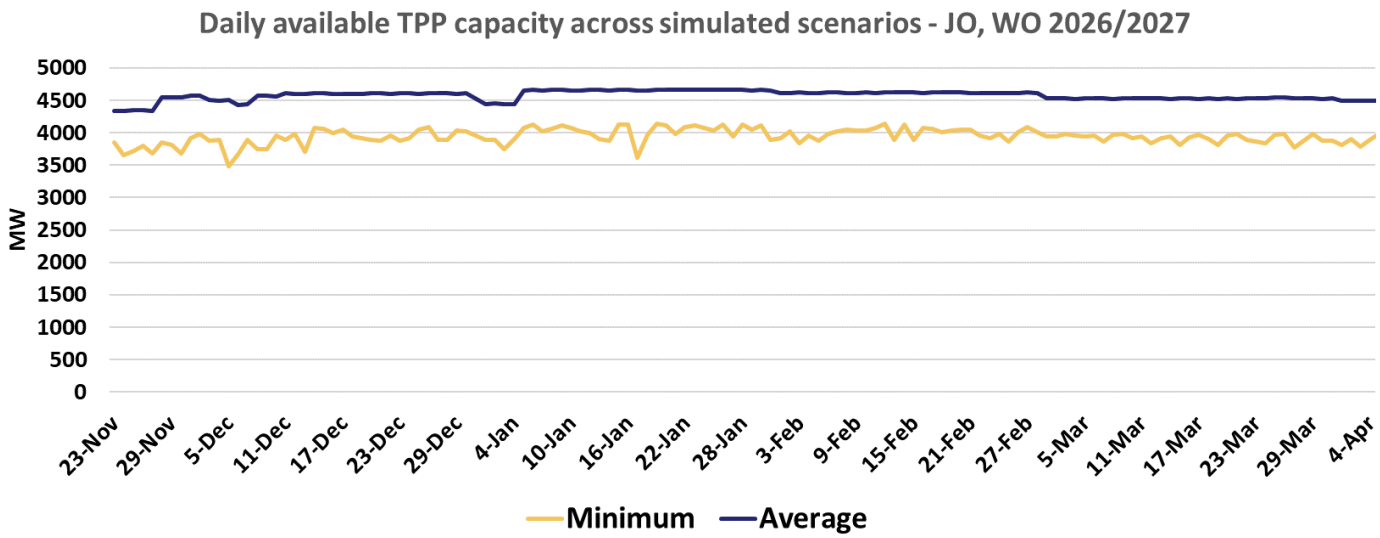


Figure 16 Average and minimum TPP available capacity among all simulated MC years in Jordan.

The worst-case hourly margin presented in Figure 17. highlights Jordan's potential adequacy vulnerabilities during the winter period. From late November until approximately the end of February, the margin remains at or close to zero, indicating minimal thermal capacity headroom under the most stressed simulated conditions.

The margin begins to recover in early March, with short-lived peaks reaching approximately 520 MW by early April. This recovery appears consistent with reduced maintenance requirements and lower demand, rather than a structural improvement in the supply position.The prolonged period of near-zero margins highlights Jordan's limited domestic flexibility under stressed conditions and the importance of the 450 MW import capacity from Egypt in mitigating adequacy shortfalls during peak demand.

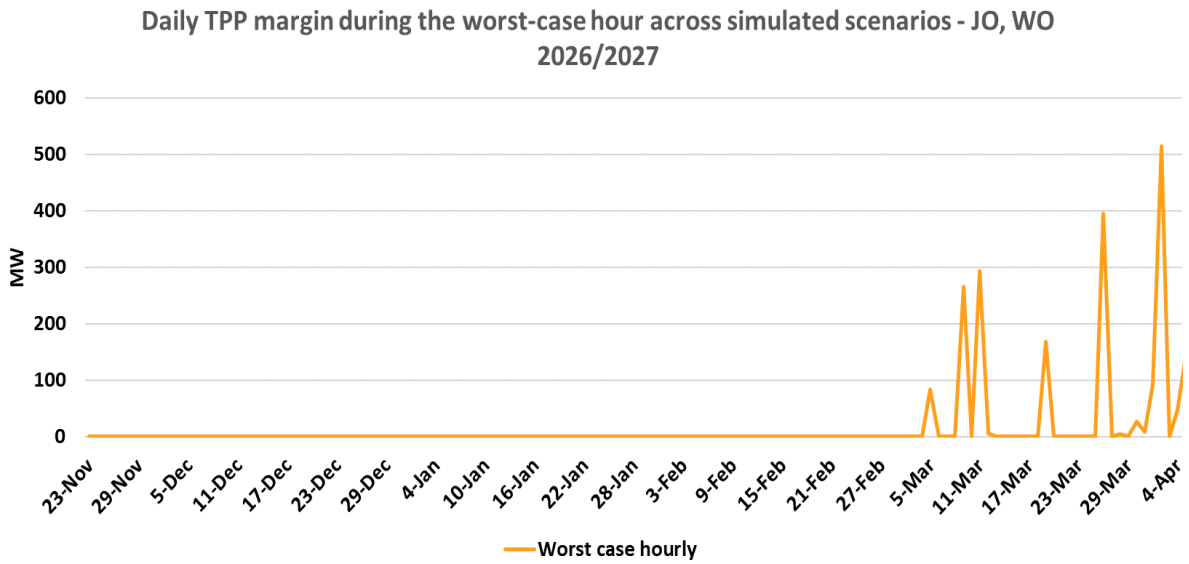


Figure 17 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Jordan.

ADEQUACY ASSESSMENT

Figure 18 breaks down the daily adequacy risk across the season for Jordan, isolated and interconnected shown side by side, with LOLE in the first panel and EENS in the second.

On the right-hand side of the figure, LOLE and EENS for the entire season for both system operation modes are provided. Isolated risk clusters around the middle of the season — daily LOLE touches 0.3-0.45 hours at its worst, and daily ENS tops out just under 100 MWh, mostly between late December and mid-February. Outside that window — late November into mid-December, and from March onward — risk is essentially absent.

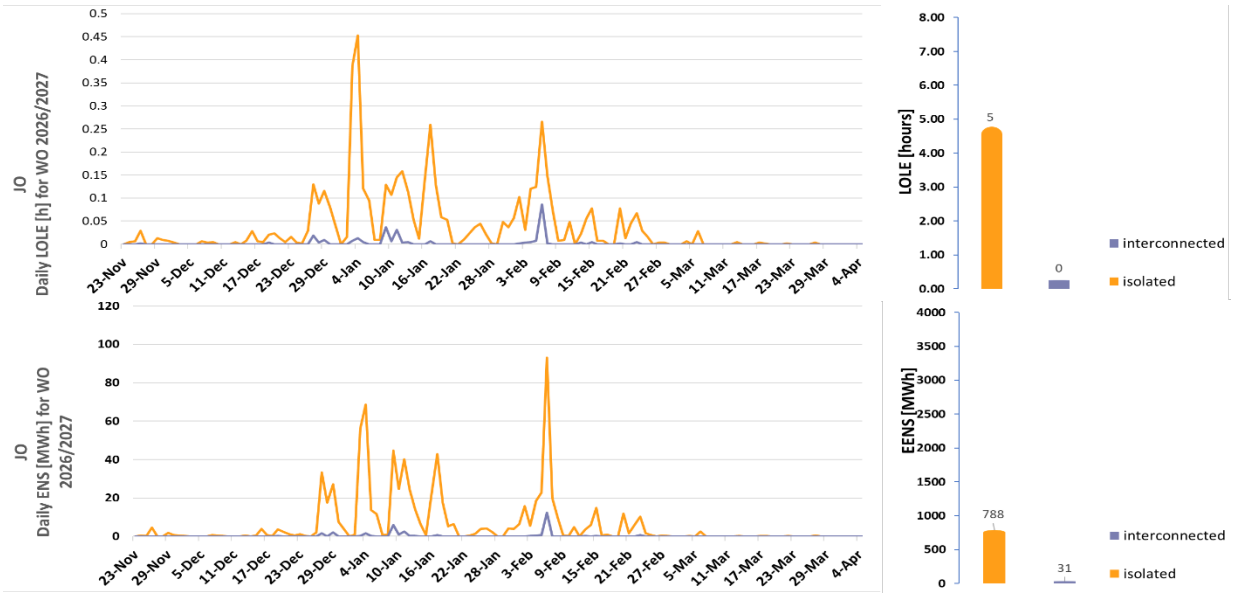


Figure 18 Daily LOLE and EENS for the interconnected and isolated operation modes in Jordan.

Interconnection with Egypt effectively suppresses most of this risk, bringing daily LOLE and ENS values close to zero throughout the season.

Seasonally, isolation brings roughly 5 hours of LOLE and about 788 MWh of EENS; interconnection cuts both close to nothing — near-zero LOLE and around 31 MWh of EENS. Jordan's position is already comfortable on its own, and regional exchange all but closes the small gap that remains.

5.3. Lebanon

DEMAND

Lebanon's winter weekly demand in Figure 19 ranges from approximately 457 GWh to 524 GWh, while P95 weekly peak hourly demand ranges from 3,667 MW to 4,766 MW. Weekly energy is the 36-year average and peak demand is the P95 weekly maximum. Demand peaks in week 6 of 2027, reflecting colder weather and higher heating requirements. The demand profile used for this adequacy assessment represents an unconstrained electricity requirement: the load that could arise if reliable supply were continuously available at an economically sustainable cost. This common planning basis permits comparison with the other Mediterranean systems assessed. It is higher than demand currently expressed under Lebanon's prolonged electricity and economic crisis; the crisis-adjusted trajectory is approximately 18.3 TWh in 2026 and 18.9 TWh in 2027, whereas approximately 24.3 TWh is used as an unconstrained annual planning reference. The latter is a sensitivity based on 2020 demand, not a forecast of immediate demand recovery in 2026 or 2027.

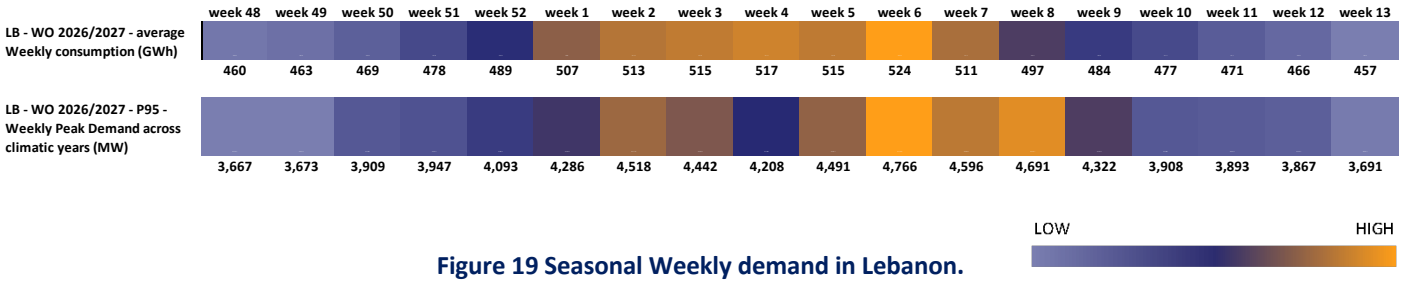


Figure 19 Seasonal Weekly demand in Lebanon.

SUPPLY AND NETWORK OVERVIEW

Lebanon's generation mix differs markedly from those of the other countries assessed. Although "Other Non-RES" and "Light oil" collectively account for the majority of installed capacity, these categories do not fully capture the operational constraints affecting the thermal fleet. Many units originally intended to operate on natural gas rely on oil-based fuels due to the absence of an operational gas supply, increasing operating costs and limiting reliable generation. Some units remain effectively unavailable because their operating costs are prohibitively high.

Solar power, predominantly comprising rooftop installations, represents the largest individual technology share at 38% of NGIC. Its expansion largely reflects investment by households and businesses seeking to compensate for unreliable grid supply. Hydropower accounts for a further 7%.

Renewable sources collectively represent 44.9% of NGIC, one the highest proportion among the countries covered in this report. However, this share should be interpreted in the context of Lebanon's supply constraints and the expansion of decentralised generation in response to persistent electricity shortages.

Although total installed capacity is nominally close to the modelled peak demand, a substantial share is unavailable or economically constrained. Effective dependable capacity is therefore much lower than nameplate capacity. Private diesel generation and rooftop solar PV supply part of end-user consumption outside EDL's central generation fleet. Their treatment in the demand profiles and adequacy model must be considered when interpreting the shortfalls; neither should be subtracted again from modelled EENS if already reflected in the model inputs.

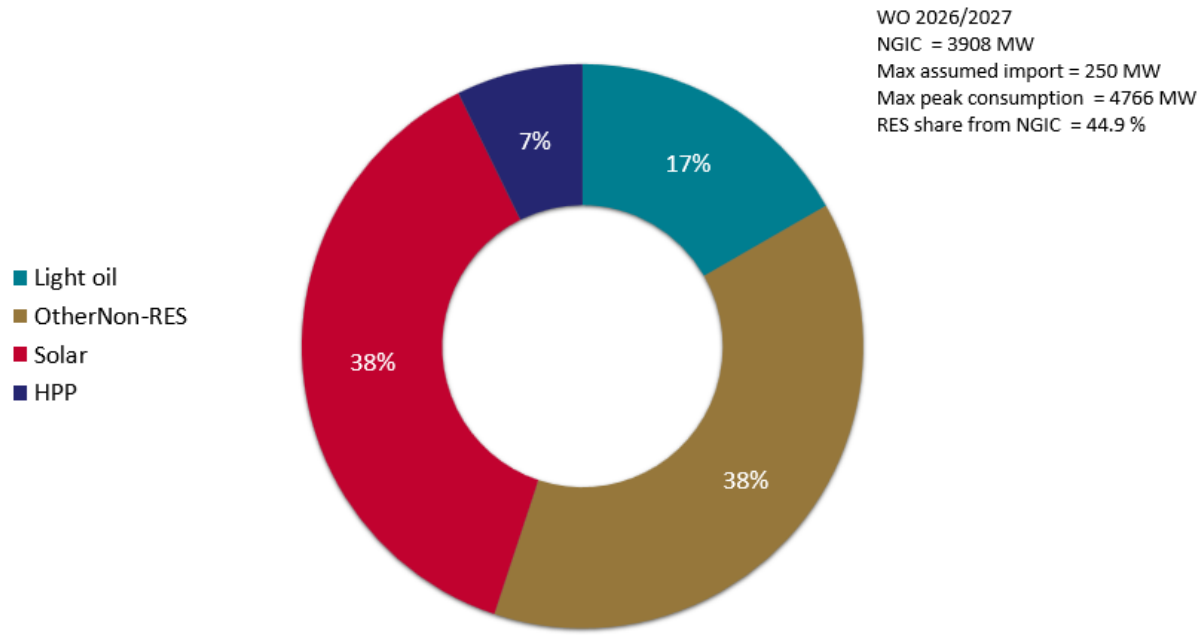


Figure 20 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Lebanon.

Figure 21. presents the average daily available thermal power plant (TPP) capacity after accounting for forced outages. Each daily value is averaged across all simulated Monte Carlo (MC) years and is identical for isolated and interconnected operation.

Lebanon's net generating capacity (NGC) represented in the model is below maximum expected hourly unconstrained demand. Average daily available thermal capacity across the simulated MC years is approximately 2,000 MW, illustrating the limited dependable supply relative to this planning demand. The comparison indicates the scale of capacity and energy required for reliable service as demand recovers; it should not be interpreted as the current observed shortfall at every hour.

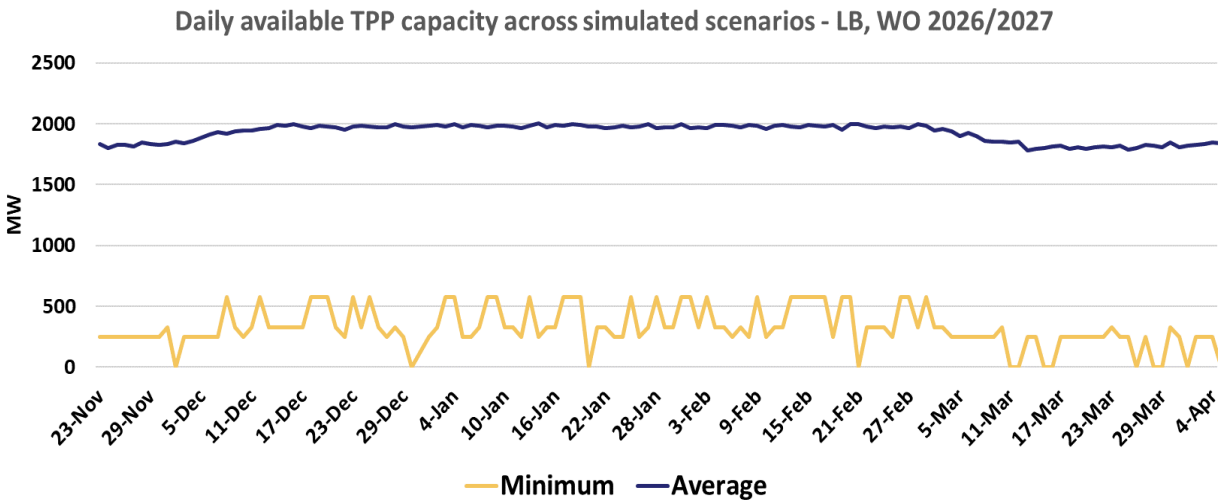


Figure 21 Average and minimum TPP available capacity among all simulated MC years in Lebanon.

Figure 22 shows the minimum hourly thermal power plant (TPP) capacity margin across all simulated MC years, defined as available less dispatched TPP capacity. Under the modelled unconstrained demand, the minimum margin reaches zero throughout the analysed period, indicating that available thermal resources are fully utilised in the most stressed simulations.

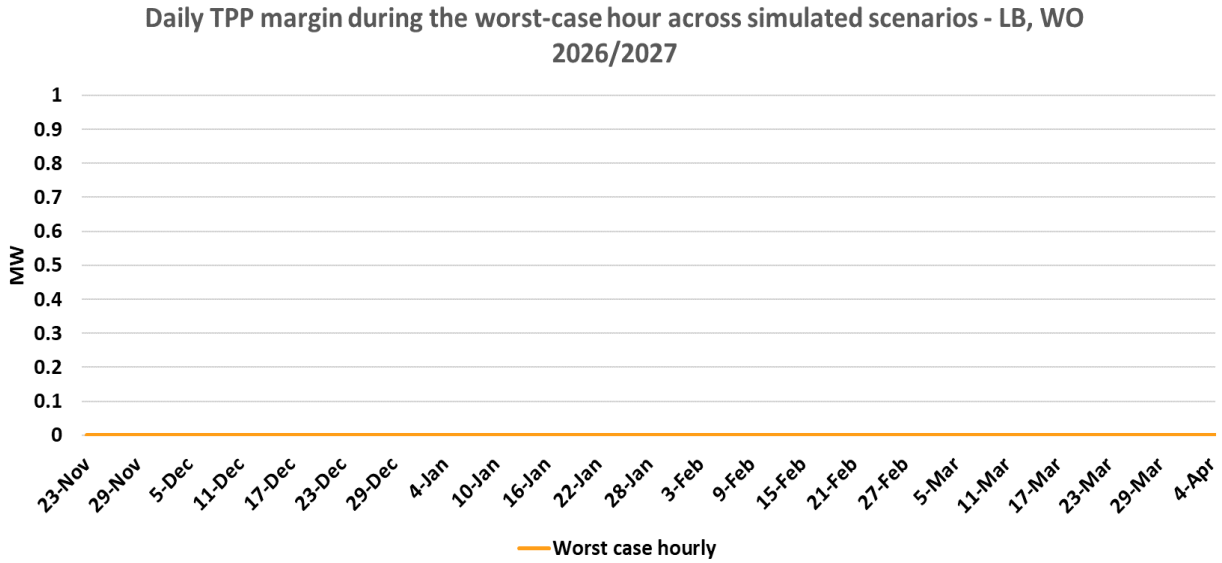


Figure 22 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Lebanon.

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 has the highest modelled adequacy risk under the common unconstrained-demand basis, which represents potential requirements as reliable supply and economic activity recover.

Daily LOLE is approximately 15–24 hours in isolation and 15–22 hours with interconnection. These simulated shortfalls are not measured end-user outages; private generation, rooftop PV and suppressed demand affect actual consumption.

Seasonal LOLE and EENS fall from approximately 2,904 hours and 3.79 TWh in isolation to 2,655 hours and 3.04 TWh with the interconnection. Interconnection gives partial relief; dependable domestic supply remains essential. Future studies should show both demand cases and account explicitly for distributed supply without double counting.

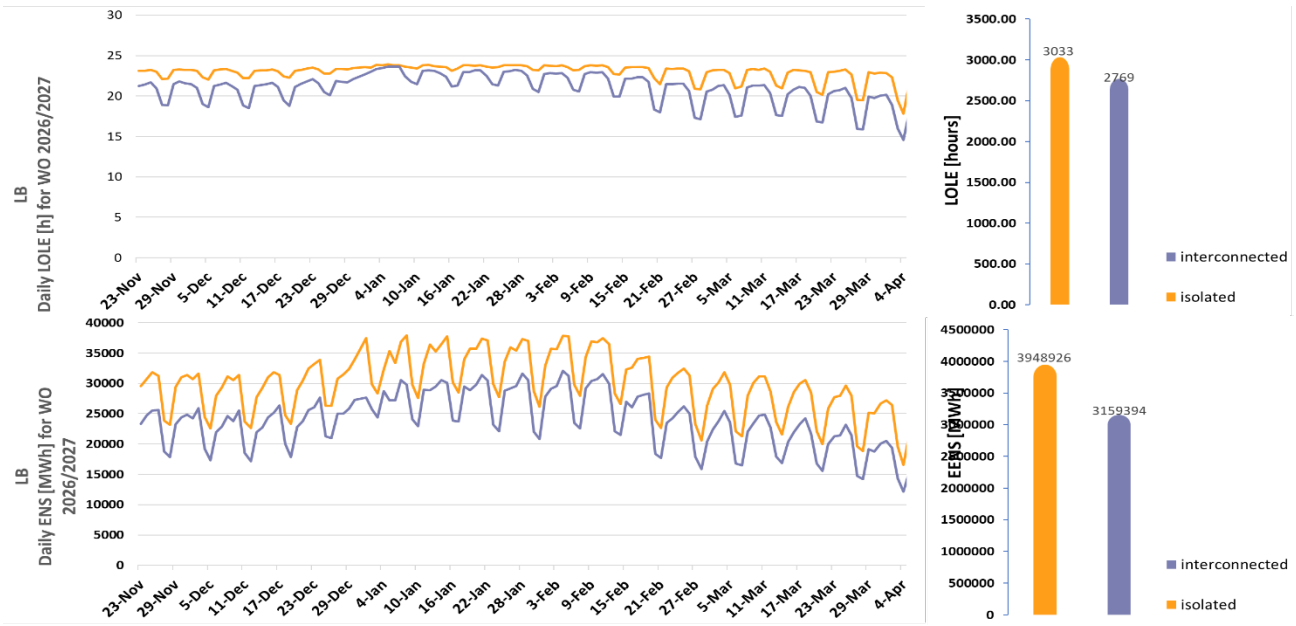


Figure 23 Daily LOLE and EENS for the interconnected and isolated operational modes in Lebanon.

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 winter weekly demand Figure 24, ranges from around 829 GWh to 1,122 GWh, with P95 peak hourly demand between 6,941 MW and 9,374 MW — weekly figures averaged across 36 climatic years, peaks taken as the P95 weekly maximum over the same set.

Demand peaks earliest here of all six countries, in week 1 of the new year.

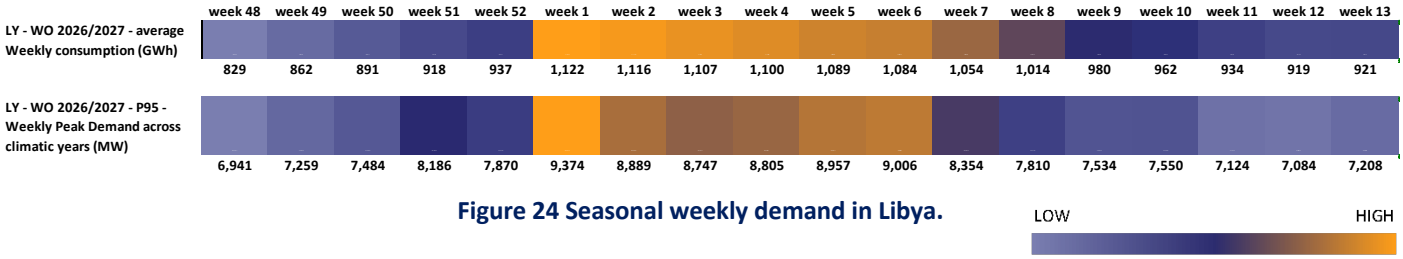


Figure 24 Seasonal weekly demand in Libya.

SUPPLY AND NETWORK OVERVIEW

Libya's generation is fossil-fuelled from end to end — the only system in this report with no renewable contribution at all for WO 2026/2027. Natural gas carries the bulk of installed capacity, with light and heavy oil making up what remains.

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 thin.

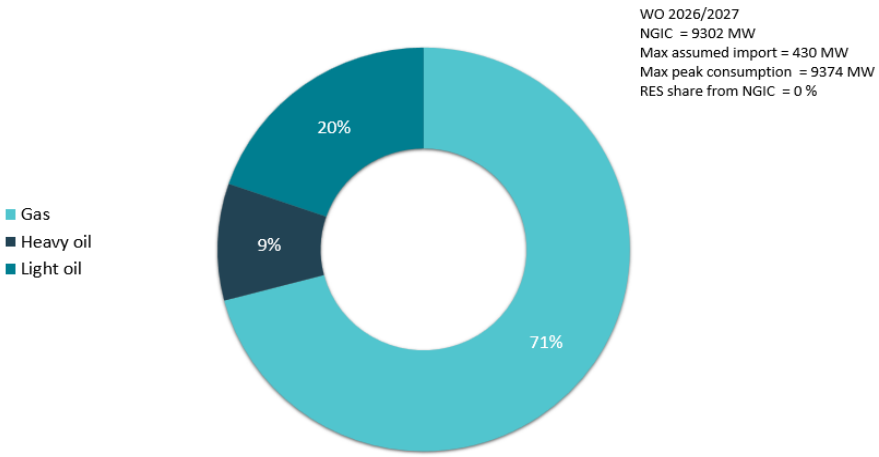


Figure 25 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Libya.

Figure 26.shows average daily available TPP capacity after forced outages. It climbs from around 7,700 MW in late November to a high of roughly 8,700 MW around late January/early February, then eases back to somewhere between 7,500 MW and 8,100 MW as the season winds down. The lowest daily figure across all analysed MC years falls between about 5,100 MW and 7,300 MW.

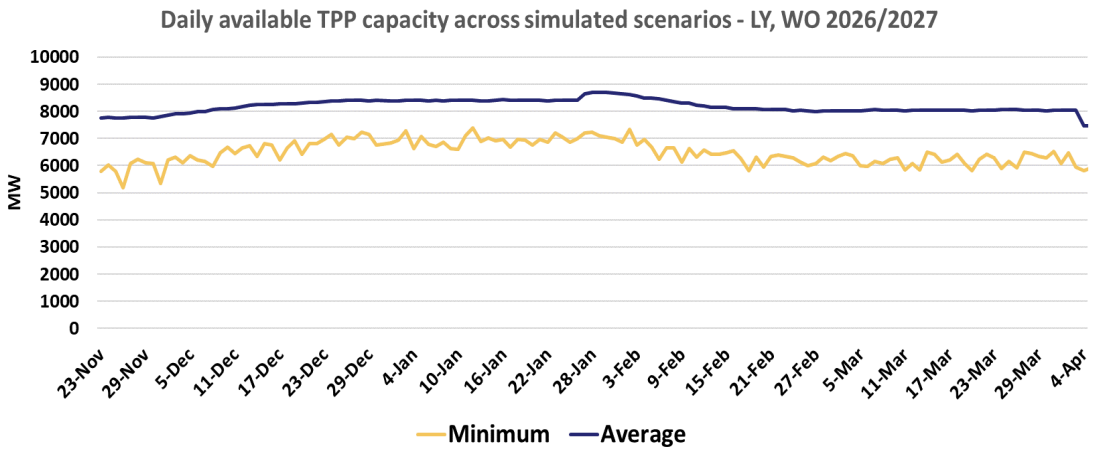


Figure 26 Average and minimum TPP available capacity among all simulated MC years in Libya.

Figure 27's worst-case hourly margin is is among the most pronounced indicators of adequacy risk in this dataset — it sits flat at or essentially at zero for nearly the entire winter, from 23 November through to early April, with just one brief exception: a single-day spike to around 25 MW in mid-December. In the worst simulated scenarios, Libya's thermal fleet is running at full stretch on almost every day of the season, with next to no buffer to absorb a unplanned outage or demand spike.

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.

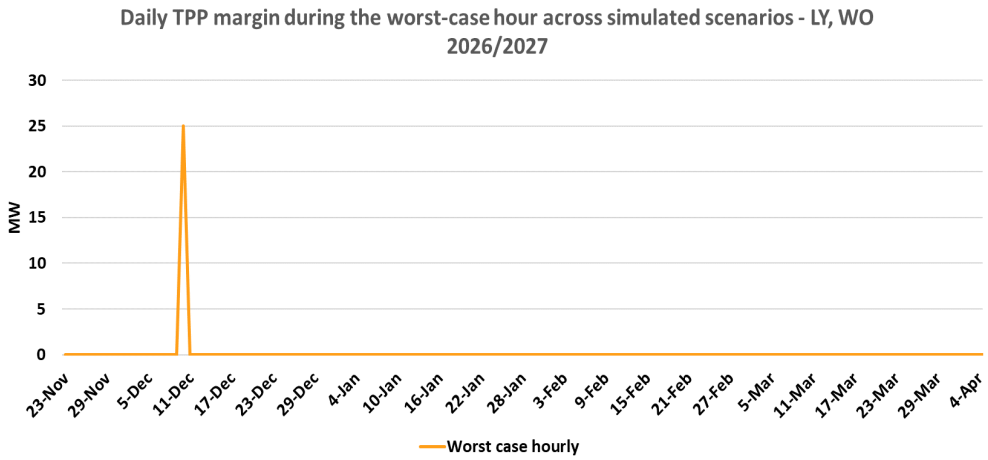


Figure 27 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Libya.

ADEQUACY ASSESSMENT

Figure 28 breaks the season's adequacy risk down by day, both operating modes, with LOLE in the first panel and EENS in the second.

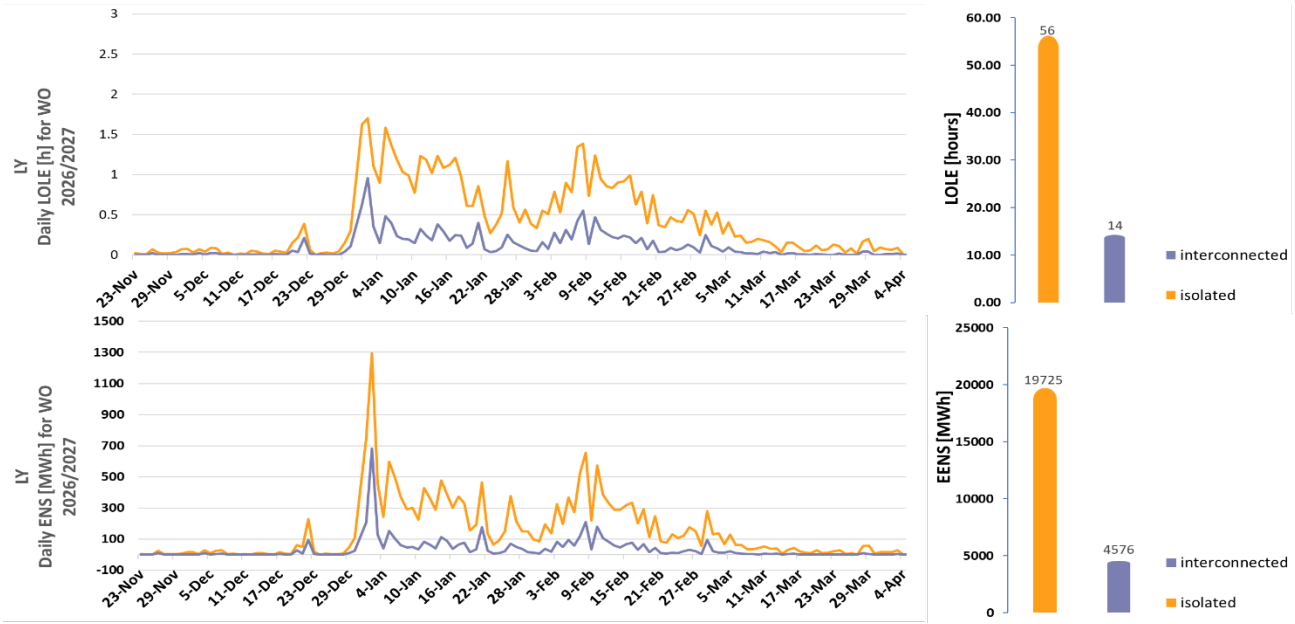


Figure 28 Daily LOLE and EENS for the interconnected and isolated operational modes in Libya

Rather than a problem that runs the whole season, Libya's risk is concentrated in a defined window. Late November through late December is essentially risk-free; shortfalls start appearing around the new year and persist, with some ups and downs, until roughly mid-February, before easing off again toward season end — in both isolated and interconnected modes.

Daily LOLE climbs sharply around the turn of the year, peaking at about 1.7 hours in early January, then eases gradually — with a smaller secondary peak in early-to-mid February — as the season closes out. Daily unserved energy follows the same arc, hitting its high point (around 1,300 MWh) in early January.

Bringing in Tunisia and Egypt roughly halves both daily LOLE and ENS across the risk window. Seasonally, that takes isolated LOLE of about 56 hours and EENS of roughly 19,676 MWh down to around 14 hours and 4,571 MWh under interconnection — a meaningful step down to a medium-risk outcome.

Risk peaks right around the new year, when demand is at its highest and the thermal fleet is under the most pressure — but between regional support and the underlying generation margin, Libya's overall exposure this winter stays at a manageable level.

5.5. Morocco

DEMAND

Morocco's winter weekly demand in Figure 29 is flat, holding between about 926 GWh and 1,003 GWh, while P95 peak hourly demand ranges narrowly from 7,194 MW to 7,470 MW — weekly figures averaged across 36 climatic years, peaks as the P95 weekly maximum.

Where most countries in this report show a clear seasonal swing, Morocco's demand barely moves across the winter — the highest weekly peak lands in late February (week 9).

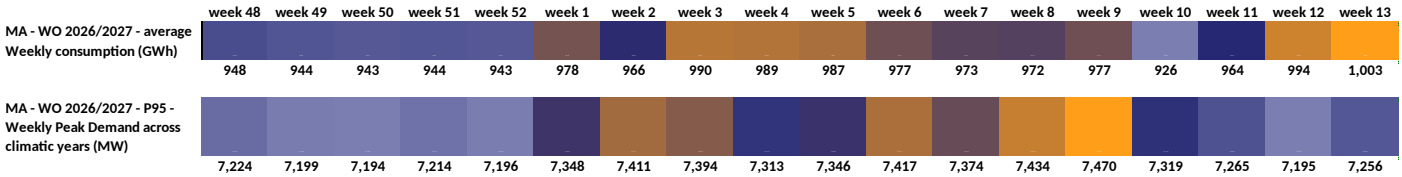


Figure 29 Seasonal weekly demand in Morocco.

SUPPLY AND NETWORK OVERVIEW

Morocco has the most diversified generation mix among the countries assessed. Hard coal constitutes the largest share of installed capacity, complemented by substantial contributions from wind, hydropower, heavy oil, natural gas and solar. This broad distribution across technologies distinguishes Morocco’s generation capcity from those of the other countries covered in the study.

RES makes up 47.9% of NGIC, led by a strong wind fleet and a growing solar contribution, with storage-backed technologies — hydro pump storage and solar CSP with storage — adding further depth. The combination of variable renewable generation and storage places Morocco in a leading position among the countries assessed in this respect. 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.

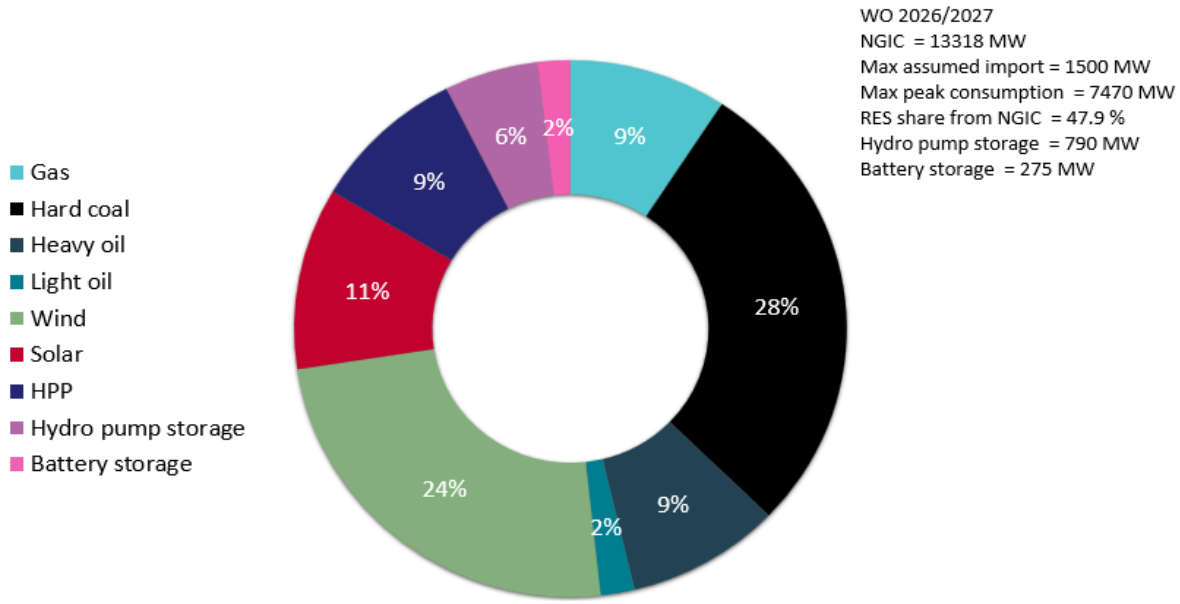


Figure 30 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Morocco.

Average daily available TPP capacity which is shown Figure 31 mostly holds in the 5,900-6,150 MW range, with a temporary lift to around 6,600 MW between early and mid-March. The minimum daily figure across all simulated MC years ranges from roughly 3,900 MW to 5,400 MW.

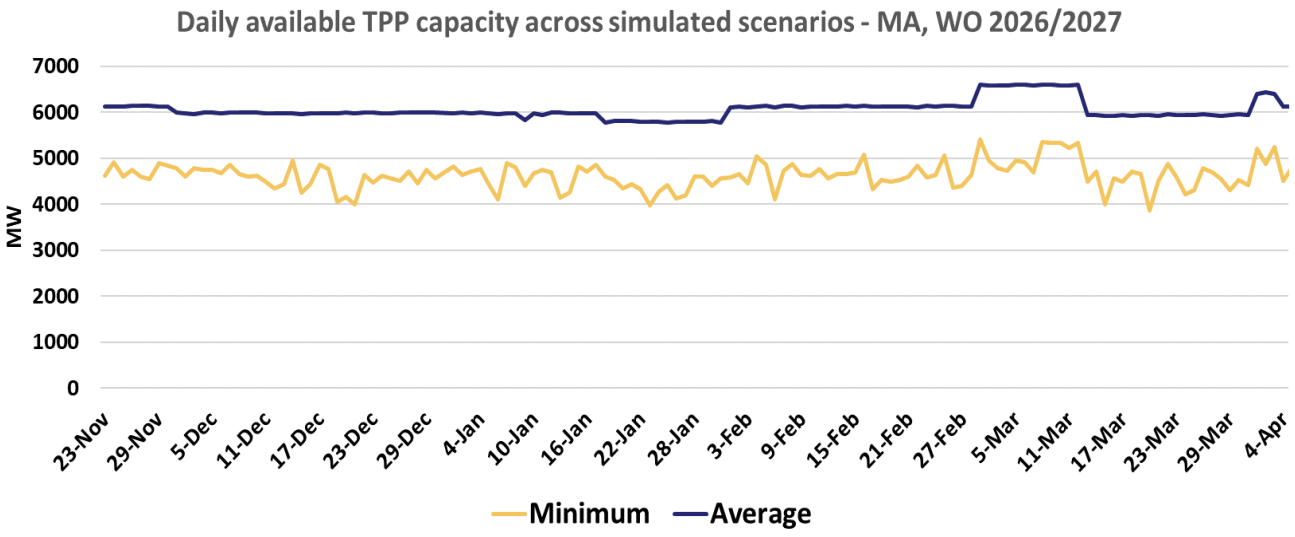


Figure 31 Average and minimum TPP available capacity among all simulated MC years in Morocco.

As a result of simulation, the minimum hourly TPP capacity margin among all simulated MC years on each day is depicted in Figure 32.

Morocco's worst-case hourly margin follows a different seasonal pattern from those of Libya and Lebanon, although it indicates greater vulnerability during early winter. From late November to late January, the margin remains at or close to zero on most days, with occasional increases above 200–300 MW. From early February onwards, it rises substantially, remaining above 1,000 MW for most of the remaining assessment period and exceeding 2,000 MW in early to mid-March.

This variation is consistent with the interaction between thermal generation availability and wind and hydropower conditions within Morocco's diversified generation portfolio. While the limited margins during early winter indicate potential exposure under stressed conditions, the improvement distinguishes Morocco from systems experiencing persistent capacity constraints throughout the season.

Available import capacity from Spain provides additional support during periods of limited domestic margins, contributing to Morocco's favourable overall adequacy position.

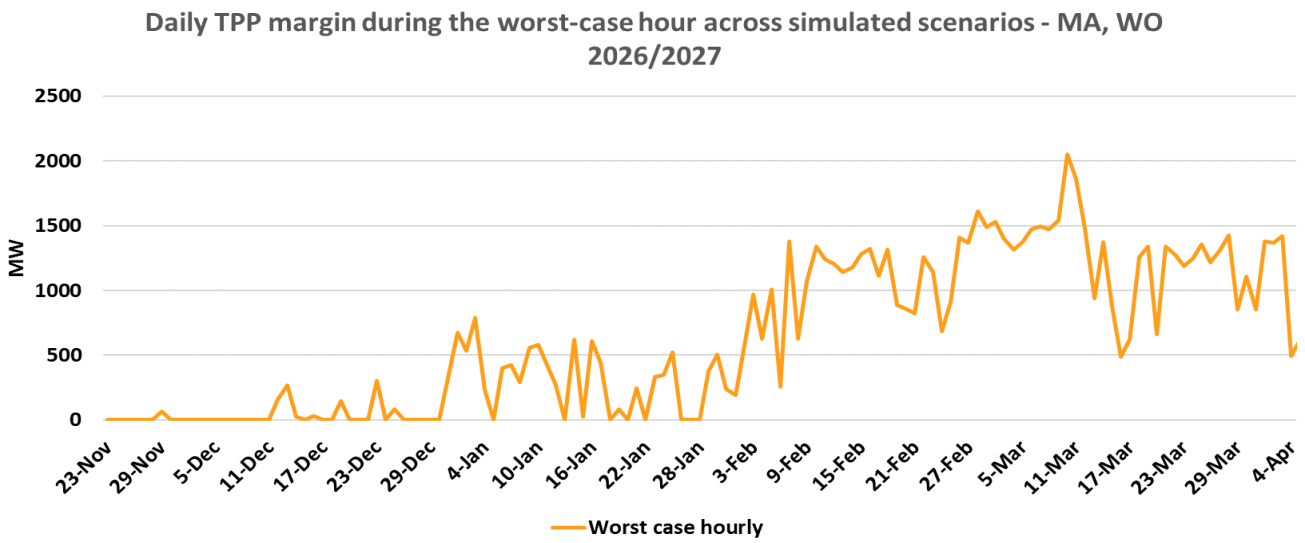


Figure 32 Minimum hourly TPP margin on each day of the analysed period in Morocco.

ADEQUACY ASSESSMENT

Morocco's daily LOLE and EENS chart Figure 33 tells a reassuring story: risk sits flat at zero for almost the entire season. A limited number of minor fluctuations appear between late November and late December, and one somewhat larger spike shows up around 28 January -- the single most notable moment of the whole winter, though even then daily EENS only reaches about 4.5 MWh.

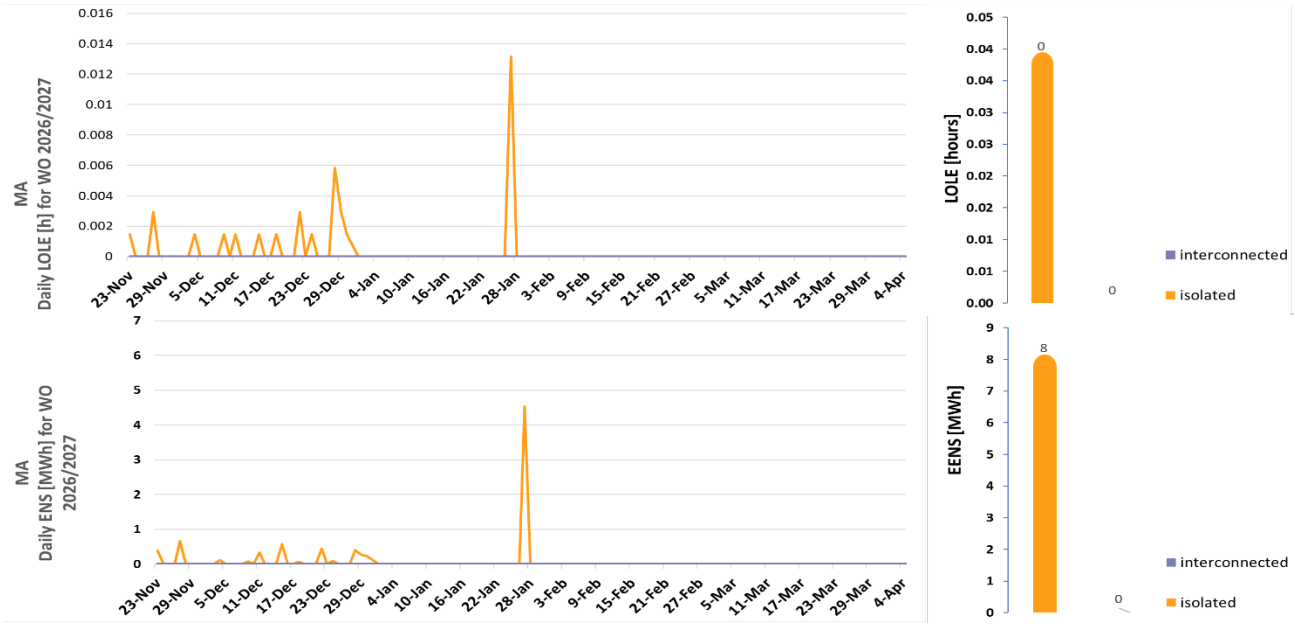


Figure 33 Daily LOLE and EENS for the interconnected and isolated operational modes in Morocco

From February through early April, the chart shows nothing at all. Across the full season that adds up to just 8 MWh of isolated-mode EENS and 0.02 hours of LOLE **Table 8** and interconnection erases even that, bringing both figures to zero. No adequacy concerns are detected for either operational mode in Morocco's case.

5.6. Tunisia

DEMAND

Tunisia's winter weekly demand Figure 34 falls between 408 GWh and 457 GWh, with P95 peak hourly demand from 3,361 MW to 3,916 MW — weekly figures averaged across 36 climatic years, peaks taken as the P95 weekly maximum. Demand peaks earlier in the season than most, clustering in weeks 2 to 5 (through January)

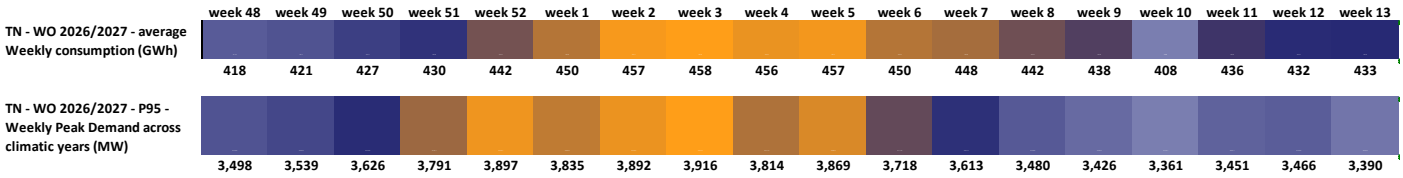


Figure 34 Seasonal weekly demand in Tunisia.



SUPPLY AND NETWORK OVERVIEW

Natural gas dominates Tunisia's generation mix much as it does Egypt's, though Tunisia's buffer against demand is noticeably thinner. Solar and wind together account for a modest 19.8% of NGIC — early movement toward diversification, but not yet enough to meaningfully loosen the system's dependence on gas.

Tunisia's installed capacity exceeds peak demand by about 63%, and thermal capacity alone covers peak with a margin of roughly 30%. Only in the most stressed simulated conditions does the thermal margin reach zero making the 500 MW import capacity from neighbouring countries a precaution for these events rather than a day-to-day necessity.

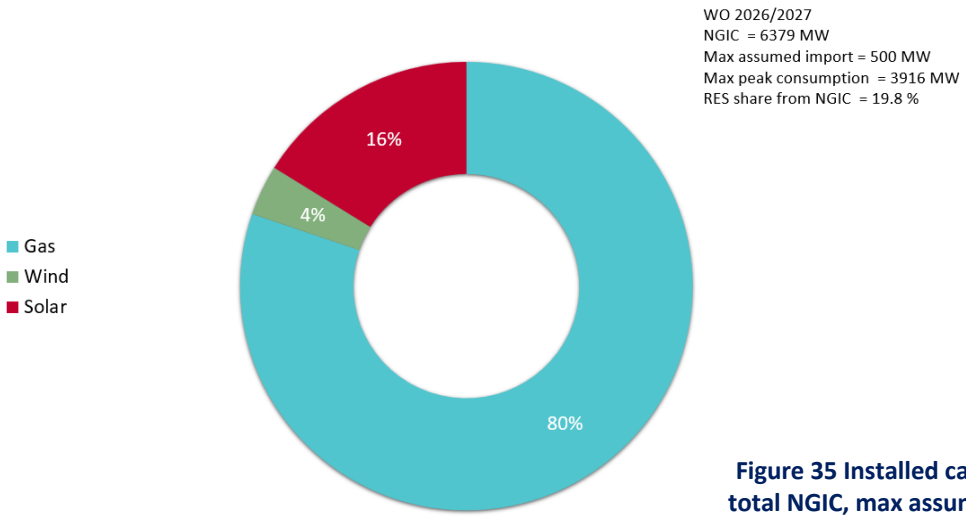


Figure 35 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Tunisia.

Average daily available TPP capacity, which is shown in Figure 36 mostly sits between around 4,300 MW and 4,900 MW across the 684 MC years, with a brief early peak near 4,950 MW around late November/early December. The minimum daily figure dips lower, to around 3,000-3,100 MW.

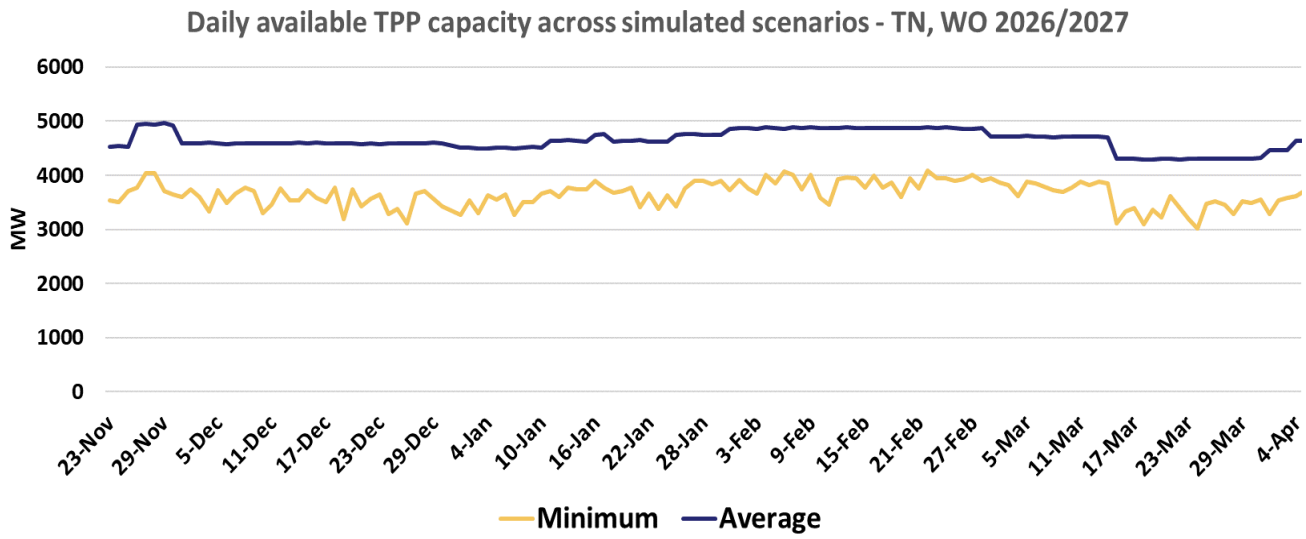


Figure 36 Average and minimum TPP available capacity among all simulated MC years in Tunisia.

The worst-case hourly margin shown in Figure 37 exhibits considerable variability throughout the winter. It falls to zero at several points, particularly in mid-to-late December, early January and mid-to-late March, before recovering to several hundred megawatts and occasionally exceeding 800 MW. An overall upward trend is evident from late January to early March.

This pattern indicates that Tunisia's thermal fleet approaches its available capacity limits repeatedly under the most stressed simulated conditions, although these constraints do not persist continuously or remain concentrated within a single period.

Tunisia's overall adequacy risk nevertheless remains low. The recurrence of limited margins across the season highlights the value of reliable access to imports as a precautionary measure throughout winter, rather than solely during a specific peak-demand period.

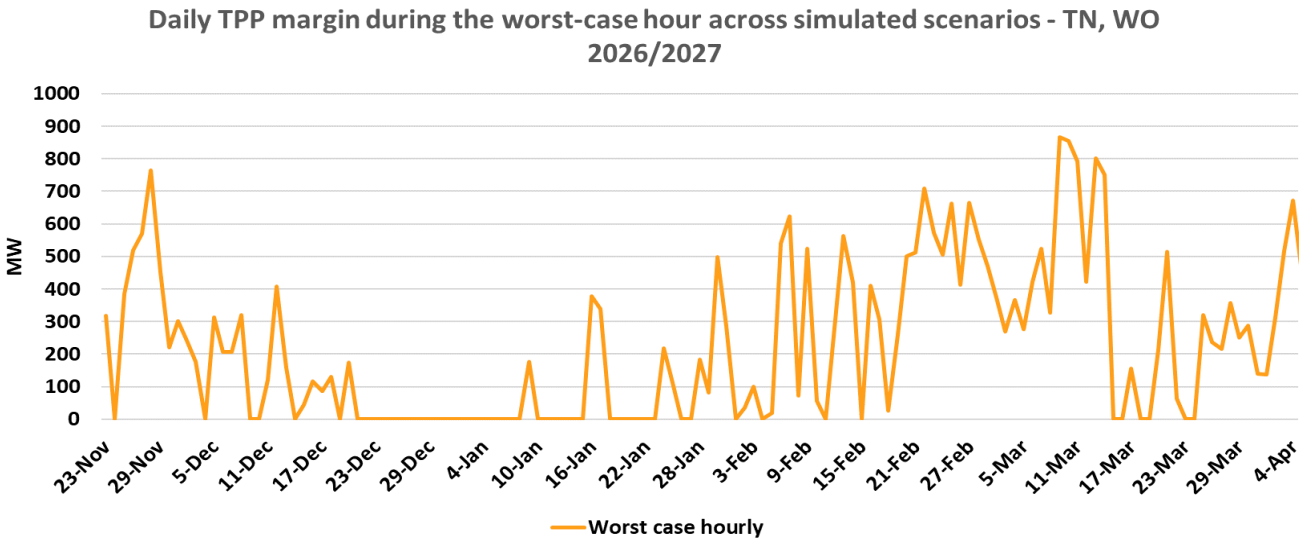


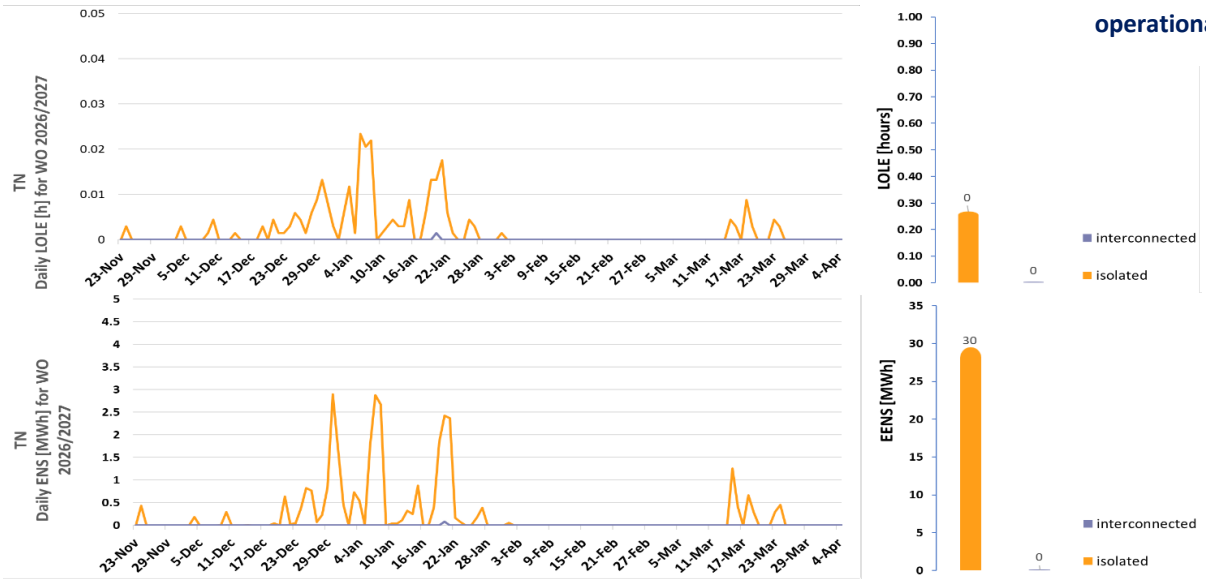
Figure 37 Minimum hourly TPP margin on each day of the analysed period in Tunisia.

ADEQUACY ASSESSMENT

Figure 38 presents Tunisia's daily adequacy risk throughout the winter assessment period under isolated and interconnected operation, with LOLE shown first, followed by EENS.

Tunisia's adequacy risk remains very low. The limited shortfalls observed are concentrated mainly between late December and mid-January, with a smaller cluster in mid-to-late March. Daily LOLE values are of the order of hundredths of an hour, while EENS amounts to only a few megawatt-hours. February records virtually no adequacy risk. Interconnected operation eliminates almost all residual risk, with both indicators remaining at zero for nearly the entire season. However, given the already negligible risk under isolated operation, the absolute improvement is low.

Figure 38 Daily LOLE and EENS for the interconnected and isolated operational modes.



Seasonally, isolated LOLE totals around 0.3 hours with EENS of roughly 30 MWh — both essentially eliminated under interconnected operation.

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.

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[3].

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.
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

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

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 39 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.

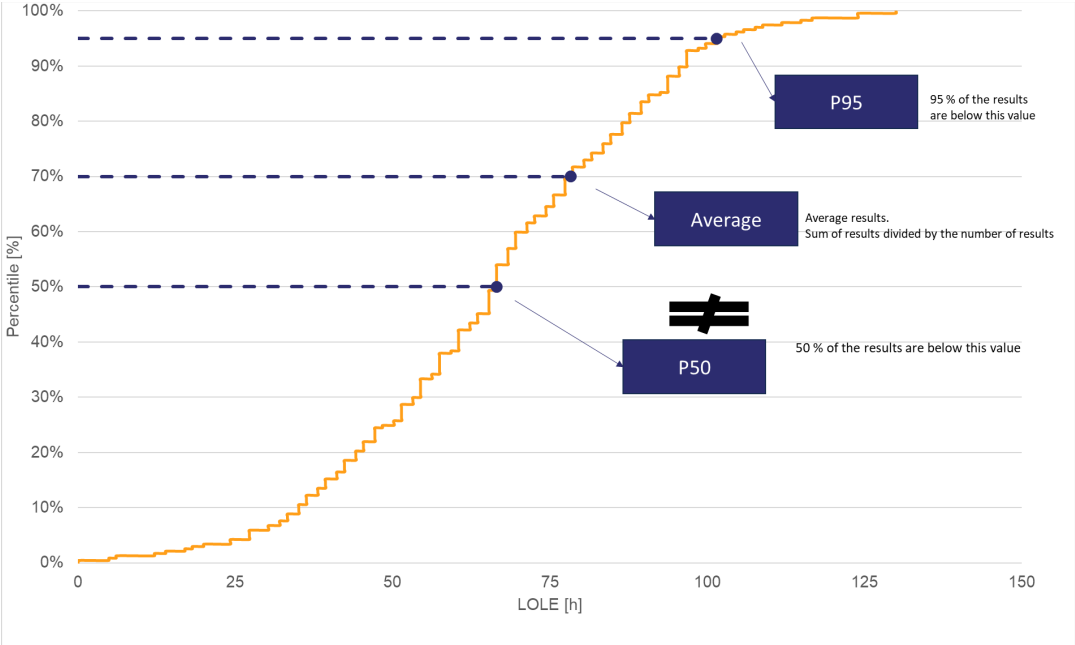


Figure 40 Illustrative example of the relation between average, P50, and P95 values.

- **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.

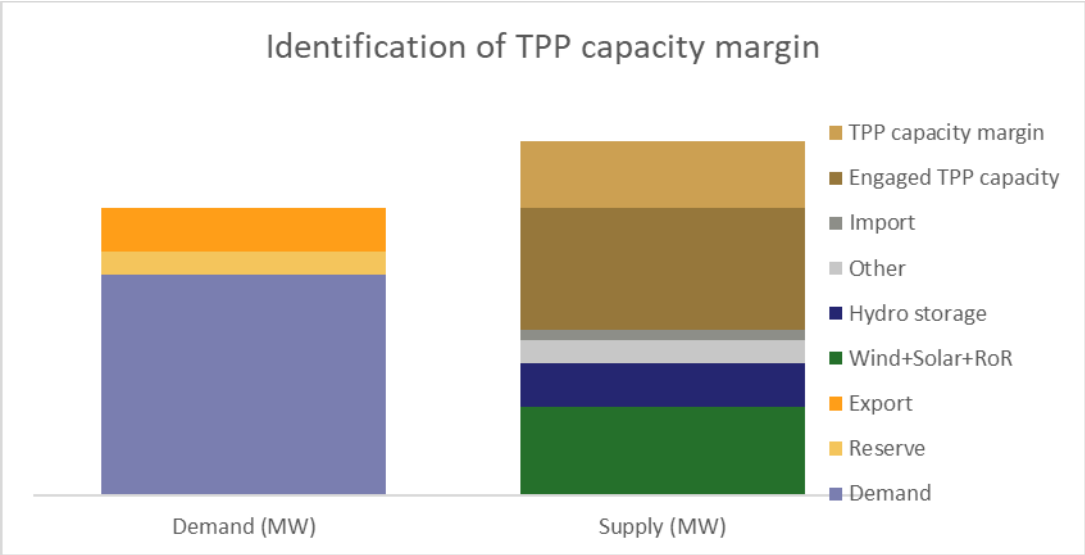


Figure 41 Illustrative example of TPP capacity margin identification.

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 42
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 42. This would allow the detection of which weeks are most at risk.

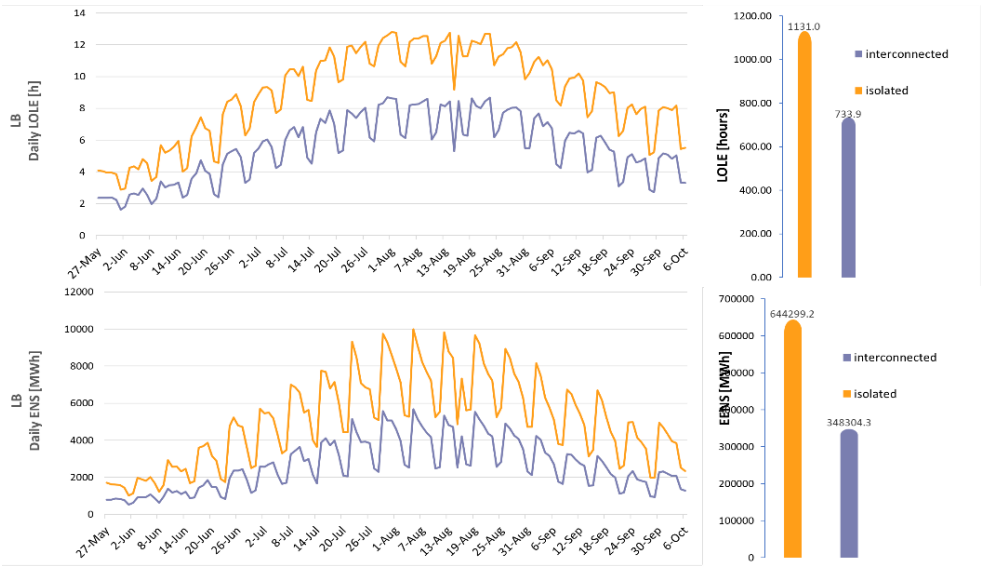


Figure 42 Illustrative example of average daily LOLE and EENS.

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.

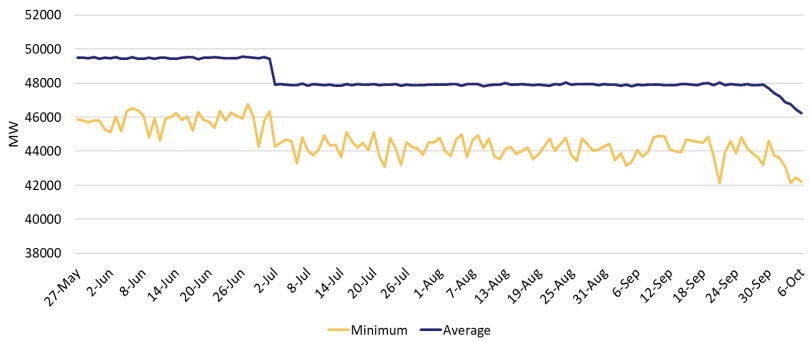


Figure 43 Illustrative example of available TPP capacity.

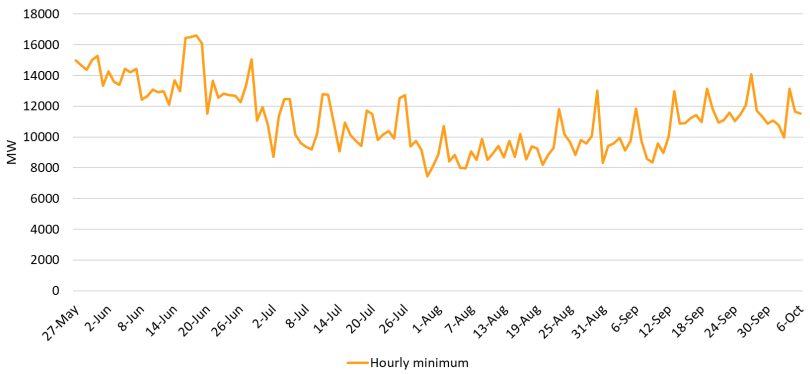


Figure 44 Minimum hourly TPP margin on each day of the analysed period.

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[4], TYNDP 2020/2022, ERAA 2021, and any other relevant documents from the ENTSO-E website.

[4] 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 4.2 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:

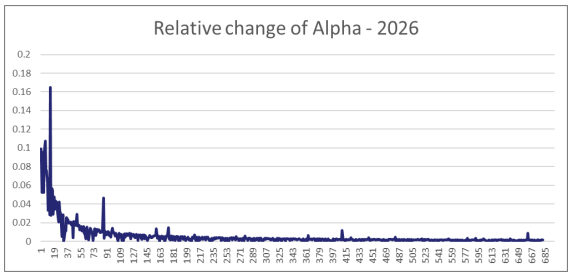
- Climate years (each of 36 years from PECD v4.2) are selected one by one.
- Each climate year is associated with random outage samples, i.e.. randomly assigned, unplanned (and planned) outage patterns for thermal units.

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.



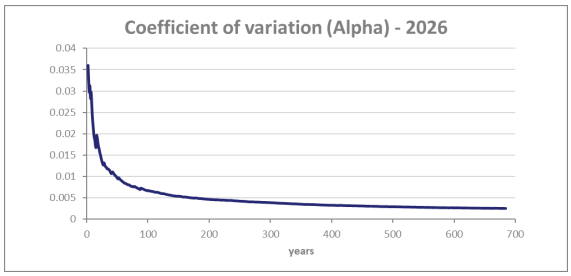
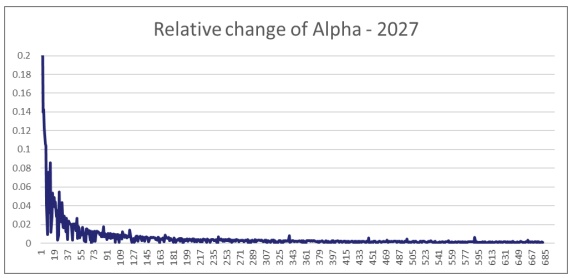


Figure 45 Evolution of convergence criteria for 684 MC years, simulations for the year 2026.



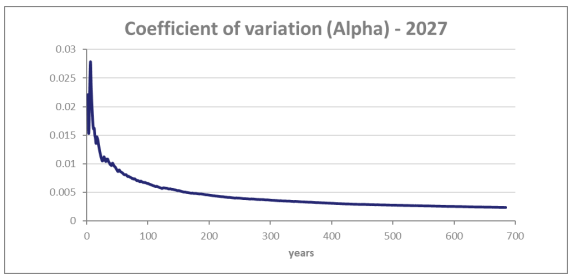


Figure 46 Evolution of convergence criteria for 684 MC years, simulations for the year 2027

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