

**SEASONAL ADEQUACY**

**ASSESSMENT**

**Winter Outlook 2024/2025**

**Detailed Report**

Released on 11.11.24



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## Abbreviations

CCGT	–	Combine Cycle Gas Turbine
EU	–	European Union
FCR	-	Frequency Containment Reserve
FRR	-	Frequency Restoration Reserve
NTC	–	Net Transfer Capacity
OCGT	–	Open Cycle Gas Turbine
O&M	–	Operating and Maintenance
PEMMDB	–	Pan-European Market Modelling Database (developed by ENTSO-E)
RES	–	Renewable Energy Sources that in general include wind, solar and hydro capacities, but in this study, RES refers only to wind and solar as VRES (Variable RES) capacities
ROR	–	Run-of-River
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 adequacy situation among non-EU Med-TSO members for the winter 2024/2025. With this assessment, Med-TSO aligns with the world-wide best practices and the latest developments of EU regulation<sup>1</sup>. These investigations consider 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 because also of the power system operation, more and more based on open market conditions; all these aspects call for the assessment of power system adequacy in the short, mid, and long run. Moreover, the integration of huge amounts of RES must be closely followed by the commissioning of devices that can provide adequate power system flexibility.

This winter outlook 2024/2025 Report provides information about potential adequacy issues during the period from 25 November 2024 to 30 March 2025 in 6 MED-TSO countries: Morocco, Tunisia, Libya, Egypt, Jordan and Lebanon.

Data for Algeria is missing during this assessment due to limited engagement from Algerian side and data for Israel and Palestine are not available at the moment.

Main adequacy indicators that have been assessed are:

- **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 expected (average) value of energy not to be supplied due to lack of resources while complying with transmission grid operational security limit.
- **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.

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 assessed to quantify the importance of interconnections.

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

Furthermore, a sensitivity analyses have been conducted to identify the most severe Monte Carlo Climatic Year (MCY) for each country.

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

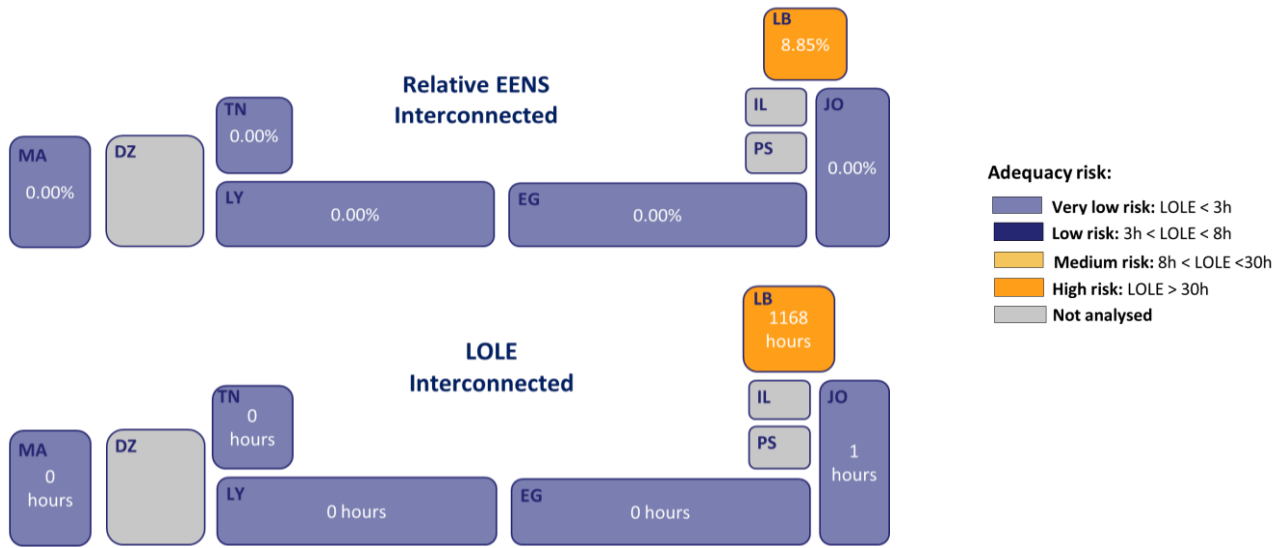


Figure 1 Seasonal relative EENS & LOLE for interconnected mode of operation.

## Conclusion

The conclusions of this assessment show that during this winter the most severe adequacy issues may occur in Lebanon (see Figure 1), where LOLE reaches around 1168 hours (around 39 % of the winter season) and energy not supplied is higher than 8.8% of the power demand in the relevant period. On the other hand, a very low adequacy risk is registered in all countries.

The situation in Lebanon is completely different, with energy not supplied during the whole winter period. However, it should be noted that the operation of the Lebanese power system is very difficult, with very frequent lack of supply and regularly scheduled load shedding programs. It should be emphasized that, in the case of Lebanon, even if all generation capacities are available and the maximum potential electricity import from the neighboring systems is taken into account, it could possibly reduce the adequacy risks but electricity demand during peak hours of the observed period cannot be supplied.

### Sensitivity case - Most Severe MCY

After identifying the most severe Monte Carlo Climatic Year (MCY) for each country, it becomes apparent from Figure 2 that interconnection plays a crucial role in mitigating its impact of the most severe MCY.

Jordan registers very low adequacy risks, with LOLE of 2 hours respectively.

However, Lebanon experiences the most severe situation during the MCY, with LOLE reaching approximately 1736 hours (around 57% of the winter season), indicating a significantly higher level of risk compared to other countries.

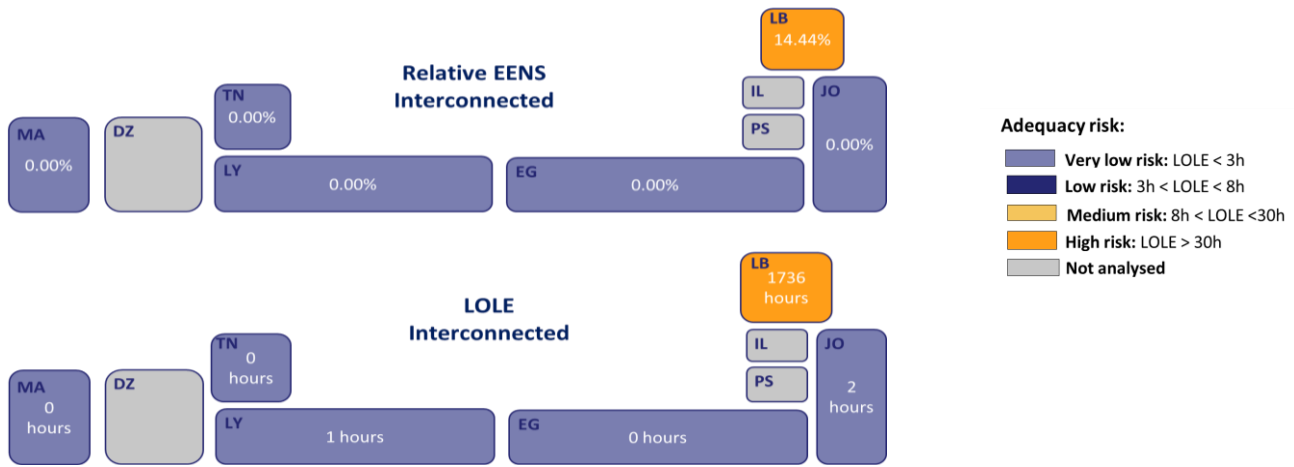


Figure 2 Seasonal relative ENS and LOLE for the interconnected mode of operation for the most severe MCY for winter.

## 2 Approach and Methodology

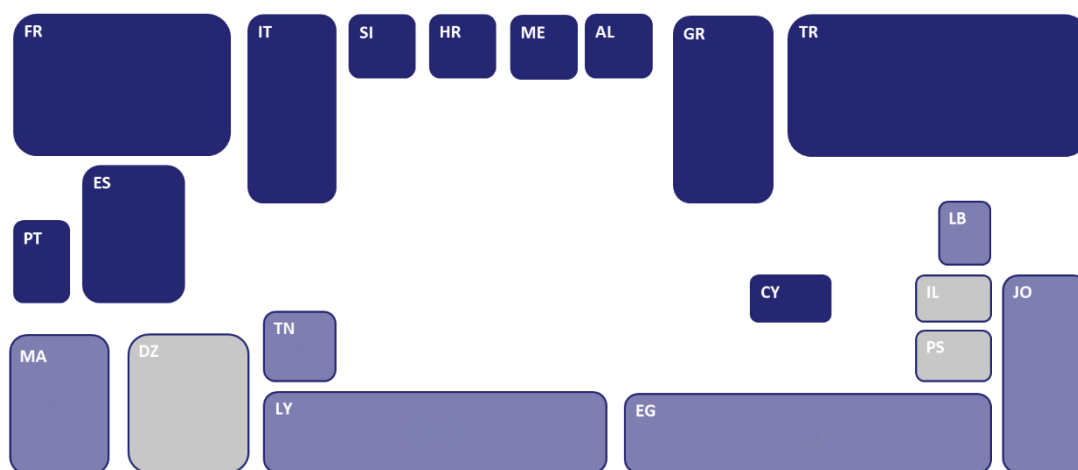
### 2.1 Adequacy assessment methodology

This Report presents the adequacy situation among non-European Med-TSO members during Winter 2024/2025. With this assessment, Med-TSO is aligning with the worldwide best practice and the latest development of the EU regulations<sup>2</sup>.

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 run. 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 decarbonize energy systems - adequacy monitoring becomes even more important.

This Winter Outlook 2024/2025 Report provides information about potential adequacy issues during winter 2024/2025 in the 6 MED-TSO members: Morocco, Libya, Tunisia, Egypt, Jordan and Lebanon.



Med-TSO members analyzed in this adequacy assessment
Med-TSO members not analyzed in this adequacy assessment
Med-TSO members taking part to the ENTSO-E adequacy study

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

<sup>2</sup> <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en>

Data for Algeria is missing during this assessment due to limited engagement from Algerian side and data for Israel and Palestine are not available at the moment.

The analyzed period includes all hours between the beginning of week 48 in 2024 till the end of week 13 in 2025 which is the period between Monday, November 25<sup>th</sup>, 2024, and Sunday, March 30<sup>th</sup>, 2025.

The analyses have been carried out with the ANTARES simulator v8.03, considering the following:

- The ANTARES (ANTARES – A New Tool for Adequacy Reporting of Electric Systems) simulator, 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 recognized and used in ENTSO-E for TYNDP and Adequacy assessments (ENTSO-E 2020 edition of the Mid-Term Adequacy Forecast (MAF) was carried out with ANTARES)
- The ANTARES simulator was already used by Med-TSO in the project “Mediterranean Master Plan 2022”.
- ANTARES Simulator is an Open-Source software; hence it is accessible to all Med-TSO members.

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

The data collection process has been carried out by our members, and it included the collection 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 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.

A number of Monte Carlo (MC) years are constructed to assess adequacy risks under various conditions for the analyzed timeframe. For all those MC years, hourly calculations are performed for the whole geographical scope.



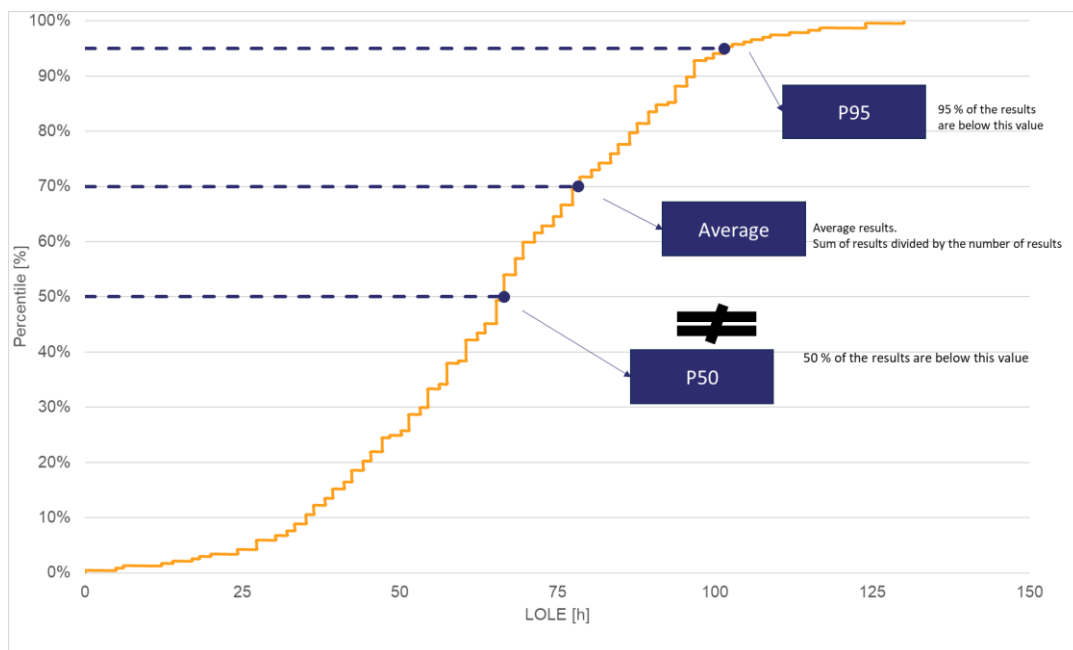
Figure 4 Probabilistic modelling general approach (source: ENTSO-E)

## 2.2 Adequacy indicators and other results of adequacy assessment

Seasonal adequacy assessment is 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 in 20 years.
  - P50: LOLD that happens once in 2 years.
- 1. **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.

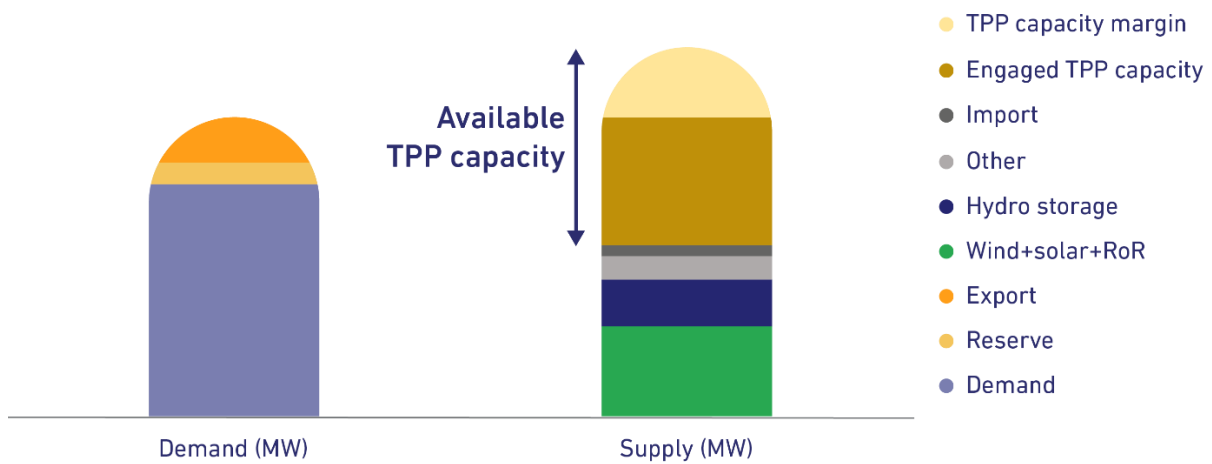
A more detailed presentation of the relations between average, P50 and P95 values is presented in the following diagram.



**Figure 5 Illustrative Example of the relation between average, P50 and P95 values.**

- **P95/P50 Energy Not Serve (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 in 20 years
  - P50: ENS that happens once in 2 years

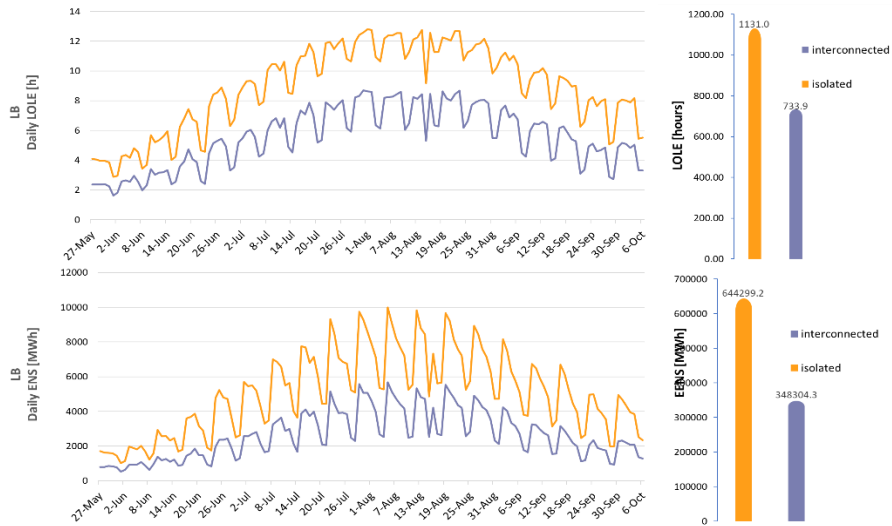
- **Expected Energy Not Served (EENS)** in a given geographical zone for a given period, is the expected (average) value of energy not to be supplied due to a lack of resources while complying with transmission grid operational security limit.
- **Relative EENS:** is a more suitable indicator to compare 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 renewable 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 6 Illustrative Example of TPP capacity margin identification.**

Presentation of the adequacy indicators also include the following:

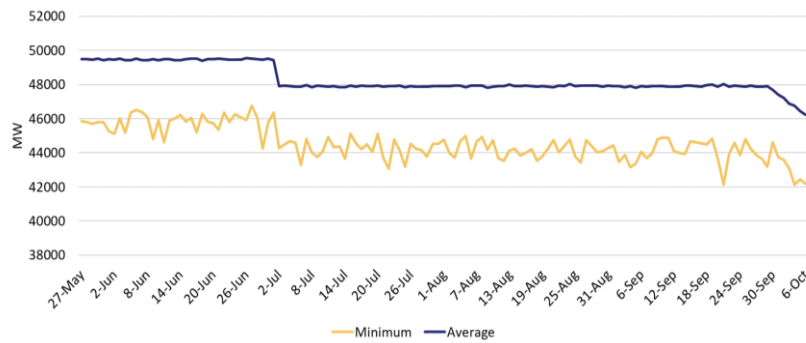
1. The seasonal spatial screening gives a general indication of the adequacy risks for the coming season in the Med-TSO region. A relative EENS indicator is used, as illustrated in **Figure 7**
2. The temporal screening gives the indication when adequacy risks are the highest. Temporal risk screening is supported by the chart of daily LOLE and EENS at the country level, as illustrated in **Figure 7**. This would allow the detection of which weeks are mostly at risk.



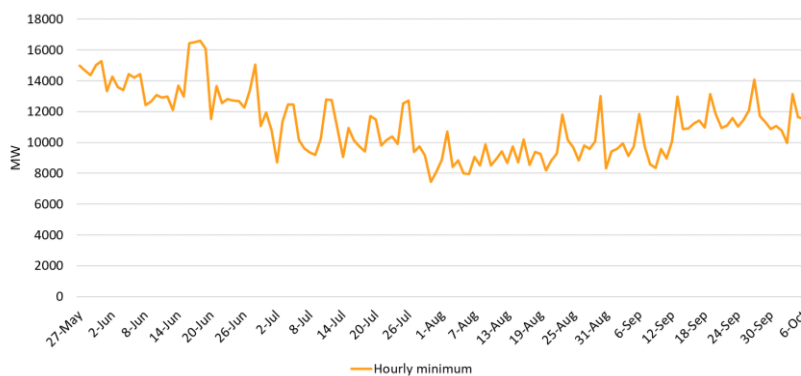
**Figure 7 Illustrative example of average daily LOLE and EENS**

The available thermal capacities and thermal capacity margins are analyzed 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 at 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 8 Illustrative example of available TPP capacity**



**Figure 9 Minimum hourly TPP margin on each day of the analyzed period**

## 2.3 Data collection and preparation of the database

This process included a collection of all relevant data and information necessary to model the power systems of Med-TSO countries. In case of missing data, standard values and appropriate assumptions have been used, all based on publicly available data from relevant sources such as National network development plans and annual reports, Med-TSO publications<sup>3</sup>, TYNDP 2020/2022, ERAA 2021 and any other relevant documents from ENTSO-E website.

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

Relevant data have been collected via standardized forms specialized for the collection of the 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.

For the Winter Outlook 2024/2025 data have been collected in August 2024.

This database will be updated in December/January 2024/2025 with the latest information that will be used for the preparation of the next report – Summer Outlook 2025.

Within data collection particular attention has been paid to the following data:

1. Hourly demand per each market area/country

Hourly demand data per each market area (country) that are modelled have 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 include losses in the transmission network but do 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 is obtained as the result of the simulations.

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<sup>3</sup> <https://med-tso.org/en/adequacystudies/>

## 2. Supply

Supply data include 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 on the unit-by-unit level. For some countries schedules for the maintenance of thermal units have been provided by our members and these schedules 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 in advance and to incorporate them many random drawings are taken, 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 used technologies and zone splitting of each country.

The 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 of 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 always kept aside (and not engaged to cover the load). This does not make any distortions in system operation results, but there may be some hours during the year in which not full balancing requirements are 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 analyzed power systems (almost no hydro generation), balancing reserve has been modelled as a negative balance (Export) with fictitious node called rest of world (ROW) in all countries having in mind that this approach is stricter and conservative providing the adequacy results that are on the safe side. Only in cases when TSO provided capacity reduction at TPPs due to FCR provision, given reduction has been applied (and only FRR requirements have been modelled as negative balance with ROW).

Considering the above-mentioned, 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 1 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 analyzed countries**
- **Isolated operation of the analyzed countries**

**Furthermore, one sensitivity analyses have been conducted to identify the following.**

- **The most severe Monte Carlo Climatic Year (MCY) for each country.**

## 2.4 Overview of the MED-TSO power systems in Winter 2024/2025

The overview is organized in alphabetical order, including submitted data, assumptions and proxies that are used to develop the corresponding market model using the Antares software tool.

All relevant parameters are presented so that the reader may check their plausibility and confirm their usability for the adequacy analyses.

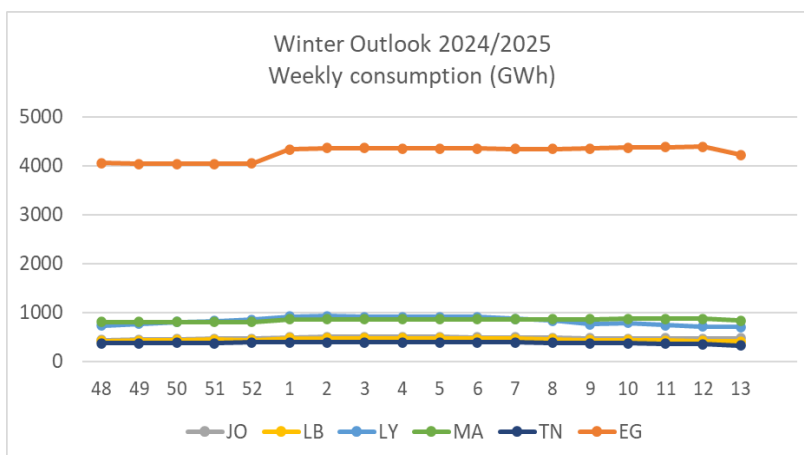
### A. Demand Evolution.

Table 1 presents the expected consumption per week from the 48<sup>th</sup> week in the year 2024 to week 13<sup>th</sup> in the year 2025. These values are the average weekly consumption for 38 climatic years in the period from 1982 to 2019.

**Table 1 Expected consumption in the winter weeks – 2024/2025.**

Weekly consumption (GWh)		EG	JO	LB	LY	MA	TN
<b>Total</b>		<b>76771</b>	<b>8631</b>	<b>8093</b>	<b>14926</b>	<b>15313</b>	<b>6845</b>
Week	<b>48</b>	4055	442	419	735	810	373
Week	<b>49</b>	4043	451	430	773	811	378
Week	<b>50</b>	4041	459	437	811	810	383
Week	<b>51</b>	4040	466	445	826	813	378
Week	<b>52</b>	4046	466	443	852	812	389
Week	<b>1</b>	4335	496	473	924	862	389
Week	<b>2</b>	4362	504	480	925	865	394
Week	<b>3</b>	4361	504	476	914	867	394
Week	<b>4</b>	4358	502	479	909	867	395
Week	<b>5</b>	4355	500	480	911	868	394
Week	<b>6</b>	4356	496	468	910	868	396
Week	<b>7</b>	4344	492	462	875	867	395
Week	<b>8</b>	4344	487	456	837	866	388
Week	<b>9</b>	4357	478	442	766	868	377
Week	<b>10</b>	4374	470	436	789	872	370
Week	<b>11</b>	4384	472	432	745	871	363
Week	<b>12</b>	4393	467	422	717	876	360
Week	<b>13</b>	4222	478	412	708	839	330

High Value
Low Value



**Figure 10 Expected weekly consumption per country in the analyzed season.**

Weekly consumption in Jordan, Lebanon and Tunisia is the lowest among the analyzed 6 countries. The highest is consumption in Egypt, almost 10 times higher. Consumption in Libya, Morocco are in between, although still with high differences among them.

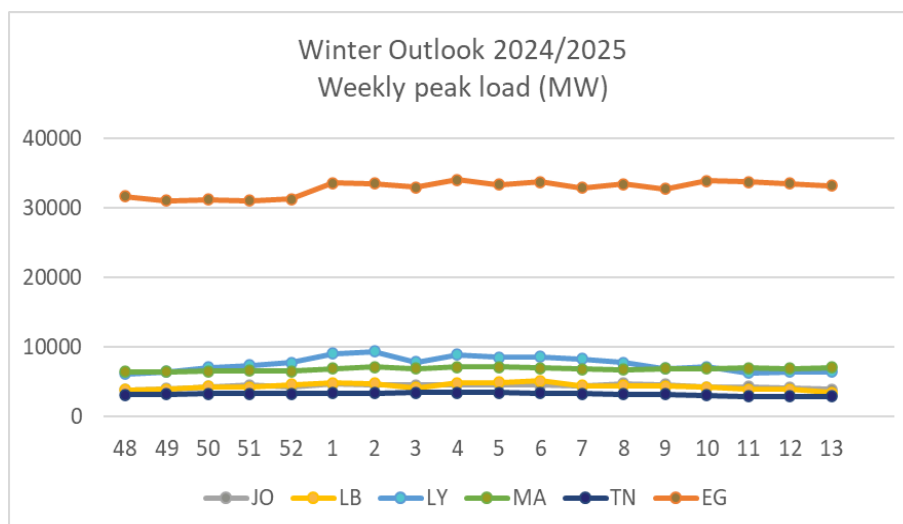
It should be noted weekly consumption is rather constant during this period.

Hourly peak demand values are presented in the following table and figure. Presented values represent maximum values among peak loads for each week for all 38 climatic years.

**Table 2 Maximum weekly peak loads in winter weeks 2024/2025**

Peak load, based on maximum among 38 CY (MW)		EG	JO	LB	LY	MA	TN
<b>Maximum</b>		<b>34062</b>	<b>4824</b>	<b>5153</b>	<b>9360</b>	<b>7175</b>	<b>3486</b>
Week	48	31657	3887	3859	6198	6488	3152
Week	49	31041	4026	3960	6491	6499	3270
Week	50	31192	4340	4343	7083	6578	3300
Week	51	31053	4583	4233	7399	6604	3330
Week	52	31293	4253	4605	7769	6589	3343
Week	1	33578	4739	4841	9108	6920	3388
Week	2	33464	4621	4785	9360	7155	3418
Week	3	32959	4580	4197	7844	6960	3470
Week	4	34062	4612	4878	8948	7175	3481
Week	5	33303	4655	4925	8539	7171	3486
Week	6	33698	4555	5153	8655	6980	3379
Week	7	32872	4437	4467	8321	6850	3353
Week	8	33386	4824	4523	7823	6823	3271
Week	9	32746	4632	4390	6926	6904	3231
Week	10	33912	4226	4269	7193	6960	3113
Week	11	33711	4314	3937	6365	6995	2936
Week	12	33455	4182	3917	6503	6940	2937
Week	13	33150	3927	3469	6451	7106	2914

High Value  
Low Value



**Figure 11 Maximum weekly peak loads per country in the analyzed season.**

In Jordan, the peak load is observed during winter, with values 10% higher than those in the summer season.

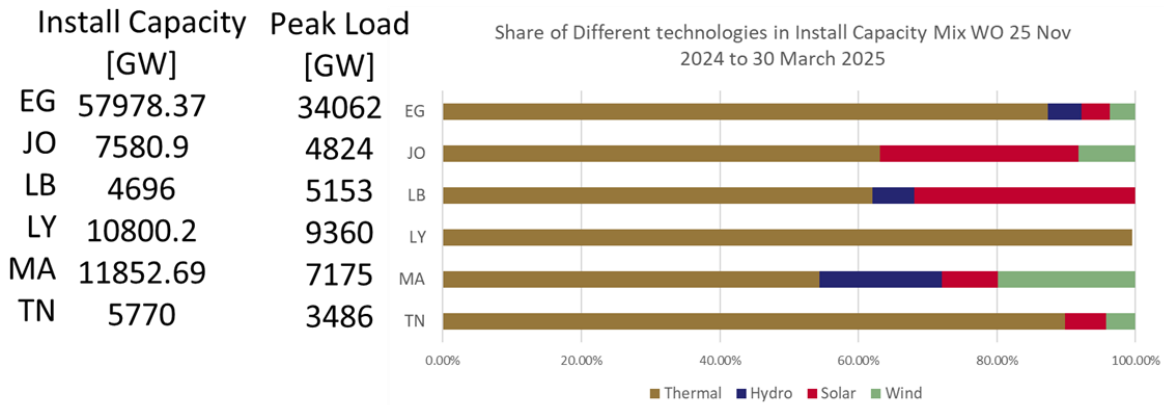
Regarding daily patterns, each country experiences seven relatively similar daily profiles, typically with one or two peaks throughout the day. In Egypt and Jordan, demand tends to be slightly lower on Fridays, while in Morocco and Tunisia, it is lower on Sundays.

#### B. Install capacities evolution.

The following tables provide information about install capacities during winter period in 2024/2025. Total install capacities in the observed region are expected to reach 100 GW, with almost 83 GW (or around 83%) in thermal units.

**Table 3 Total Install capacities (MW) per technology during winter period from Week 48 in year 2025 to Week 13 in year 2024**

Med-TSO Member	Expected WPP capacity		Expected SPP capacity		Expected HPP capacity		Expected TPP capacity		TOTAL [MW]
	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	
DZ	-	-	266	1.16%	100	0.44%	22543	98.40%	22909
EG	2136.37	3.68%	2374	4.09%	2831	4.88%	50637	87.34%	57978.37
JO	621	8.19%	2175	28.69%	-	-	4784.9	63.12%	7580.9
LB	-	-	1500	31.94%	285	6.07%	2911	61.99%	4696
LY	-	-	50	0.46%	-	-	10750.2	99.54%	10800.2
MA	2350	19.83%	961	8.11%	2096	17.68%	6445.69	54.38%	11852.69
TN	242	4.19%	345	5.98%	-	-	5183	89.83%	5770
<b>TOTAL</b>	<b>5349.37</b>	<b>4.40%</b>	<b>7671</b>	<b>6.31%</b>	<b>5312</b>	<b>4.37%</b>	<b>103254.8</b>	<b>84.92%</b>	<b>121587.2</b>



**Figure 12 Install capacity mix and peak load in winter period.**

It's important to highlight that Libya's power system relies exclusively on thermal power plants. In contrast to prior adequacy assessments, the thermal fleet has undergone a thorough re-evaluation. This reassessment takes into account the maintenance activities performed by the Libyan system, which has led to the restoration of certain power plants 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 hydro capacities exist only in Egypt and Morocco.

In Morocco, there is also a pump storage (PS) Hydro Power plant (HPP) with capacity of 464 MW. Additionally, the commissioning of a new pumped storage facility with a capacity of 326 MW has been completed

The highest wind & solar capacities participation in total generation capacities is noted in Lebanon, Jordan and Morocco where their participation reaches more than 35%. 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 also the zone splitting of each country.

**Table 4 Wind and solar capacity factors for all countries during WO 2024/2025**

Country	2024	
	Wind CF	Solar CF
EG	49.5%	26.3%
JO	33.23%	25.82%
LB	-	18%
LY	-	21.7%
MA	50.3%	30.4%
TN	30%	20%

The impact of RES generation in Egypt and Tunisia is marginal since the participation of thermal units is above 80%. Among thermal technologies, the main part is presented by gas-fired units.

Concerning thermal units, it should be noted that available capacities take into account forced outages, as well as derating factors which define the reduction in available thermal capacities due to various reasons. Planned outages are modelled according to data provided by TSOs (TN & MA) or as random outages but respecting certain predefined rules as seen in the below table:

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

Market Node	January	February	March	April	May	June	July	August	September	October	November	December
EG00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes
JO00	no	no	yes	yes	yes	yes	no	no	no	yes	yes	no
LB00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes
LY00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes
MA00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes
TN00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes

- In all countries except Jordan, planned outages are envisaged in the period from the 1st of November to 1st of April.
- In Jordan, planned outages are not envisaged in the period from 1st of December to the 1st of March.
- In Morocco & Tunisia, detailed planned outages are provided and taking into consideration during the simulations

Practically, when predetermined rule is applied, period analyzed in winter outlook should not include maintenance on any of the thermal units. This is the case also in this winter outlook.

Forced outages of thermal units are in all cases and all countries modelled as random. Similarly, for thermal units, commissioning/decommissioning dates are taken into account.

### C. Interconnections between countries

Summarized NTC values provided are used as available cross-border capacities and we assumed that these capacities are only used if a country is facing adequacy issues for the entire calculation period.

The Antares model included the power systems of 6 analyzed Med-TSO members 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. In addition to this, in the case of some 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 neighboring countries in the event of adequacy risk. Additionally, it is assumed that Algeria itself does not face any adequacy risk.

For Lebanon, we evaluated a hypothetical interconnection between Lebanon and Jordan through Syria, which enables 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.

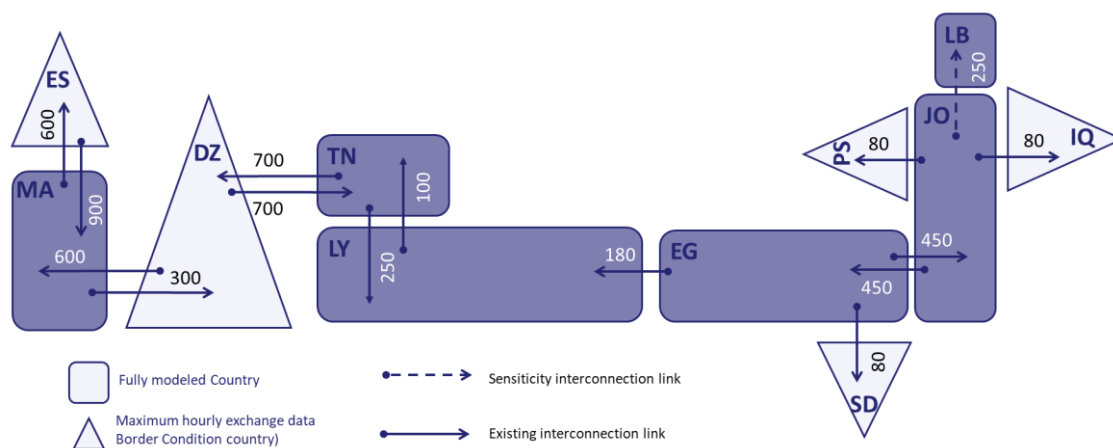


Figure 13 Net Transfer Capacity during WO 2024/2025

D. Reserve requirements and their modelling.

Reserve requirements have been provided for each country (Table 6). In some countries (LY, MA) the percentages of the 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 rest of world (ROW). FRR requirements have been modelled as a negative balance (Export) with rest of world (ROW) in all countries.

Table 6 Balancing reserve requirements.

	Reserve	WO 2024/2025
EG	FCR+FRR [MW]	1200
JO	FCR+FRR [MW]	200
LB	FCR+FRR [MW]	120
LY	FCR+FRR [MW]	250
MA	FCR+FRR [MW] <sup>4</sup>	700
TN	FCR+FRR [MW]	220

<sup>4</sup> FCR for MA has been modeled through reduced thermal capacity by total of 300 MW.

### 3 Adequacy Situation Overview

#### 3.1 Number of MC years and results' convergence

MC years have been constructed by combining climate-dependent variables (wind, solar and demand from 38 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. Then the MC combinations have been developed as follows:

- Climate years (each of 38 years from the period 1982- 2019) 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, different weather conditions and different status of the interconnections. The sufficient number of MC years that can provide sufficiently good convergence of the main results has been determined as 684 (38 x 18).

The sufficient number of MC years that ensures good convergence of results has been defined by assessing the coefficient of variation ( $\alpha$ ) of the EENS metric and its change.

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

Where EENS<sub>N</sub> 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  $Var[EENS_N]$  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.

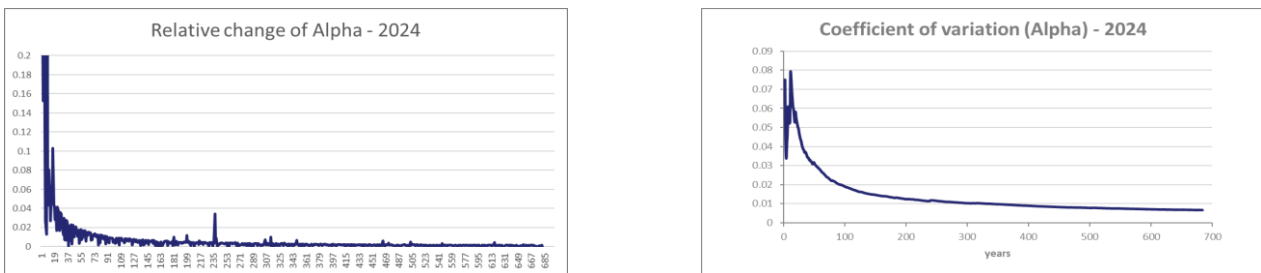


Figure 14 Evolution of convergence criteria for 684 MC years, simulations for the year 2024.

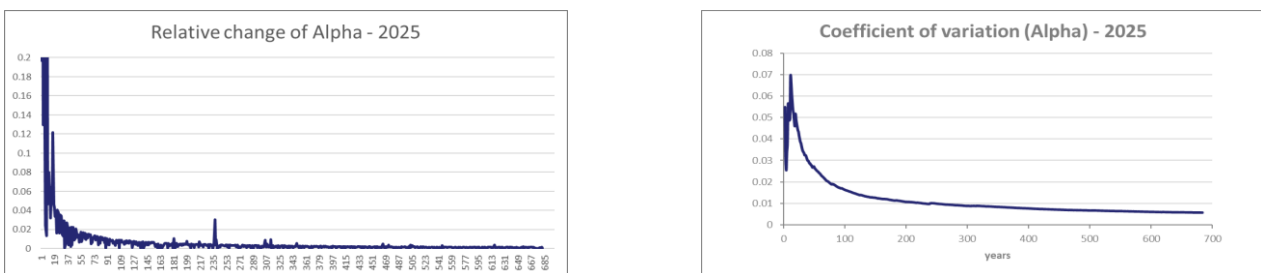


Figure 15 Evolution of convergence criteria for 684 MC years, simulations for the year 2025

### 3.2 Adequacy assessment

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 assessed to quantify the importance of interconnections.

In a theoretical isolated scenario (Figure 16), which focuses on the winter season, adequacy risks are identified in Jordan, and Lebanon. While Jordan face medium risk, Lebanon experiences a very high adequacy risk under an isolated system operating mode.

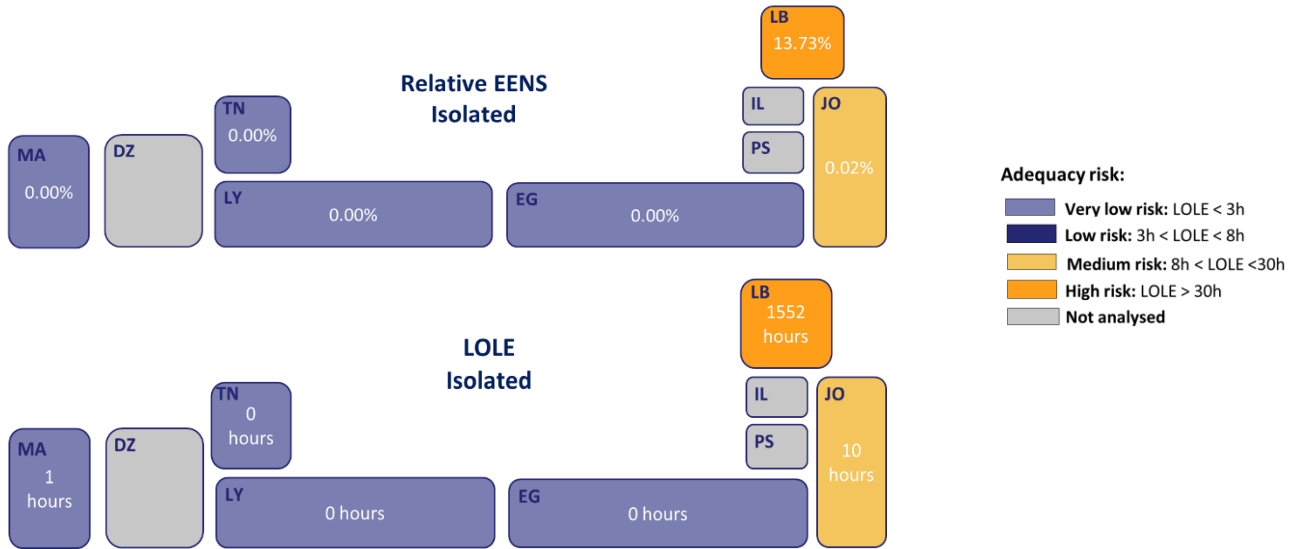


Figure 16 Seasonal Relative EENS and LOLE for the isolated mode of operation for only winter season.

Interconnections and energy exchanges needed to overcome adequacy issue with neighboring countries reduce adequacy risks to very low risk in the case of Jordan but, in Lebanon even in this more relaxed operating mode, adequacy risks are at an unacceptable level (Figure 17)<sup>5</sup> shows interconnected scenario for the winter season only.

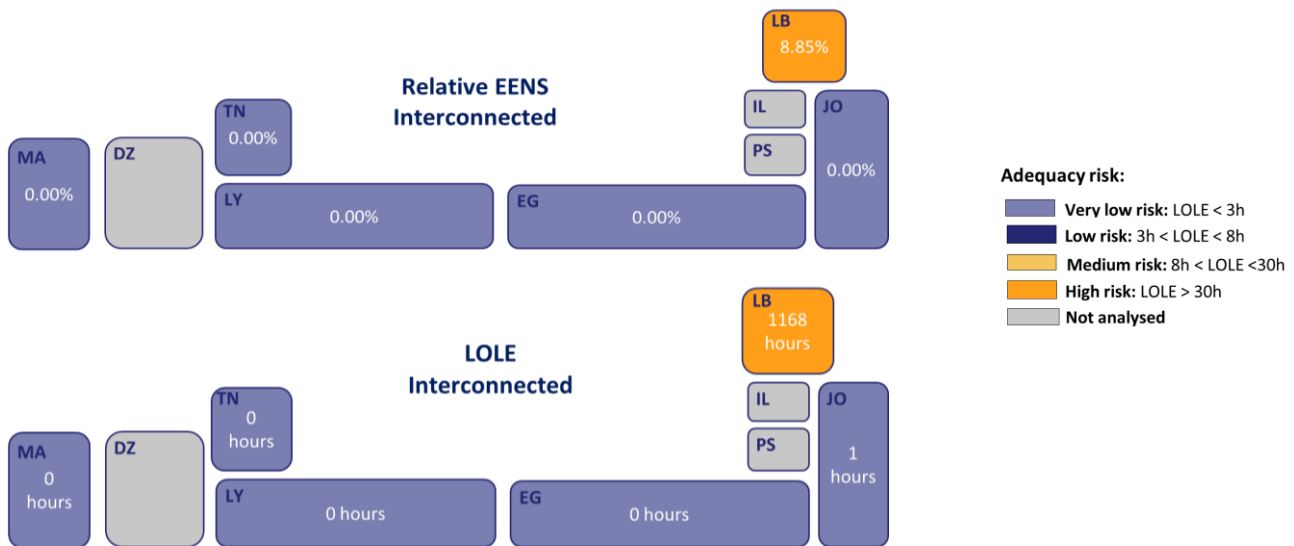


Figure 17 Seasonal relative ENS and LOLE for the interconnected mode of operation for only winter season.

<sup>5</sup> Color coding of adequacy risk levels presented in Figure 16 & Figure 17 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

Table 7 Seasonal EENS for Interconnected and isolated scenario

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	1767 MWh	104 MWh	10.01	0.73
	50th percentile 925 MWh	50th percentile 0 MWh	50th percentile LOLD: 7 hours	50th percentile LOLD: 0 hours
	95th percentile 6469 MWh	95th percentile 695 MWh	95th percentile LOLD: 29 hours	95th percentile LOLD: 4 hours
MA	311 MWh	0 MWh	0.66	0
	50th percentile 0 MWh	50th percentile 0 MWh	50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 1554 MWh	95th percentile 0 MWh	95th percentile LOLD: 4 hours	95th percentile LOLD: 0 hours
TN	14 MWh	0 MWh	0.09	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
LY	103 MWh	11 MWh	0.44	0.06
	50th percentile 0 MWh	50th percentile 0 MWh	50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 376 MWh	95th percentile 0 MWh	95th percentile LOLD: 3 hours	95th percentile LOLD: 0 hours
LB	1111462 MWh	716633 MWh	1552.06	1167.07
	50th percentile 1090754 MWh	50th percentile 693787 MWh	50th percentile LOLD: 1548 hours	50th percentile LOLD: 1158 hours
	95th percentile 1629167 MWh	95th percentile 1163545 MWh	95th percentile LOLD: 1936 hours	95th percentile LOLD: 1548 hours

**Adequacy risk:**

- Very low risk: LOLE < 3h
- Low risk: 3h < LOLE < 8h
- Medium risk: 8h < LOLE < 30h
- High risk: LOLE > 30h

In **Table 7** detailed EENS and LOLD seasonal results are given for all analyzed countries.

Results point to adequacy issues in some countries. Notable in:

- Jordan

In isolated operation mode, Jordan faces a moderate risk to adequacy, with EENS potentially reaching 1.7 GWh and LOLE lasting for 10 hours. However, in more critical P95 scenarios, EENS can escalate to 6.4 GWh with a LOLE of up to 29 hours. In contrast, when operating in interconnected mode, the risk to adequacy is minimal to only 104 MWh and LOLE of less than one hour.

- Lebanon

Lebanon experiences the highest EENS and LOLE during the winter of 2024/2025 in the region, with 716 GWh of EENS and 1167 hours of LOLE (equivalent to 39% of the time) in the hypothetical interconnected mode.

These figures highlight an extremely precarious adequacy situation (daily LOLD during the whole season can be ranged from 2 hours to 15 hours). In the event of more critical but less probable P95 cases, EENS can reach a staggering 1.1 TWh with an unavailability to supply the load for over 51% of the time.

In the isolated mode of operation, adequacy is even more at risk, with EENS reaching 1.1 TWh and LOLE extending to 1551 hours (daily LOLD during the whole season can be ranged from 4 hours to 18 hours). This emphasizes that Lebanon's interconnection with Jordan significantly reduces adequacy risks by 24%.

It should be noted that curtailment of RES generation can only happen in Jordan and Morocco in isolated operations, but this curtailment is marginal, far below 1% of RES generation.

The rationales behind these results are given in relevant country chapters.

## 4 Importance of interconnections

In this chapter, we will thoroughly explore the interconnections between the countries under analysis and their need for energy exchange to mitigate the anticipated adequacy challenges in the upcoming winter. Our primary objective is to evaluate potential cross-border exchanges among the six analyzed nations and quantify each country's requirements to address adequacy risks during periods of isolation.

The table provided below summarizes the feasible exchanges needed to overcome adequacy risk and NTC among the countries subject to our analysis.

**Table 8 Exchanges needed to overcome Adequacy in the region**

Link	Direct Exchanges for Adequacy (GWh)	NTC direct (MW)	Reverse Exchanges for Adequacy (GWh)	Reverse NTC (MW)
DZ00 - MA00	0.00	600	0.00	300
DZ00 - TN00	0.01	700	0.00	700
EG00 - JO00	5.85	450	0.00	450
EG00 - LY00	0.04	180	0.00	0
ES00 - MA00	0.27	900	0.00	600
LY00 - TN00	0.00	100	0.03	250
JO00 - LB00	379.06	250	0.00	0

Exporting electricity from Egypt to Jordan contributes positively to enhancing Jordan's adequacy. Furthermore, Egypt & Jordan are actively exporting approximately 240 GWh to meet Sudan's & Palestine energy needs while Jordan is exporting approximately 60.4 GWh to support Iraq's energy demands.

Morocco, on the other hand, relies solely on electricity imports from Spain to alleviate any adequacy concerns that may happen.

The situation in Lebanon is completely different where interconnections and imported energy play a substantial role. While interconnections help decrease adequacy concerns by 24%, they alone are insufficient to completely mitigate these potential risks.

## 5 Adequacy Situation on Country Level

### 5.1 Egypt

#### DEMAND

Egyptian winter seasonal weekly demand, depicted in **Figure 18** goes from around 4040 GWh to 4362 GWh, while peak hourly demand in each week varies from 31 GW to 34.1 GW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

As can be seen from the figure below, consumption is rather constant during the first 3 months of 2025 and higher than consumption at the end of 2024. This increase is a consequence of the expected annual increase in total consumption between these two years. Peak load is more fluctuating with maximum value at the beginning of the year 2025.

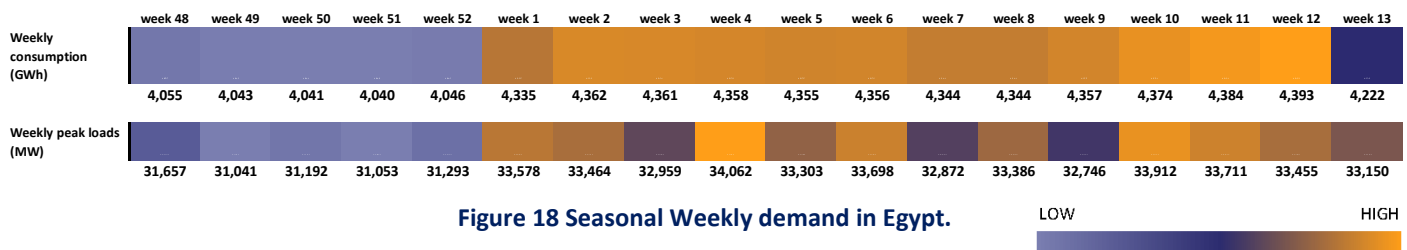


Figure 18 Seasonal Weekly demand in Egypt.

#### SUPPLY AND NETWORK OVERVIEW

Egyptian power generation fleet is almost exclusively based on natural gas, with the gas TPP share in total installed capacities around 86%, which is divided further into conventional and CCGT TPPs. Oil TPPs share is 1%, while Hydro share is 5%. RES wind and solar capacities amount only to 4% each. Total installed capacities are 50637 MW with import capacity up to 450 MW from Jordan, which combined is substantially higher than the maximum hourly consumption of 34062 MW. In sense of demand and installed capacities, Egypt is the biggest of all analyzed power systems.

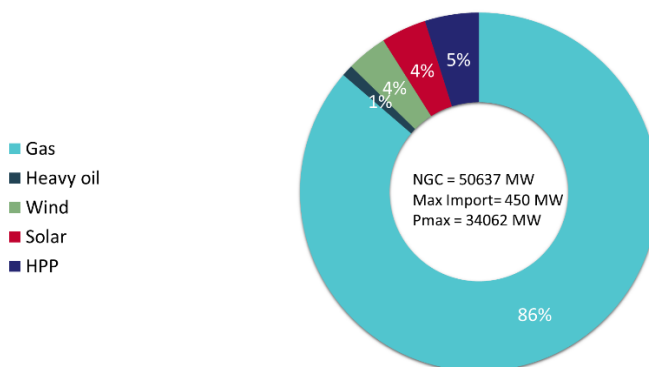
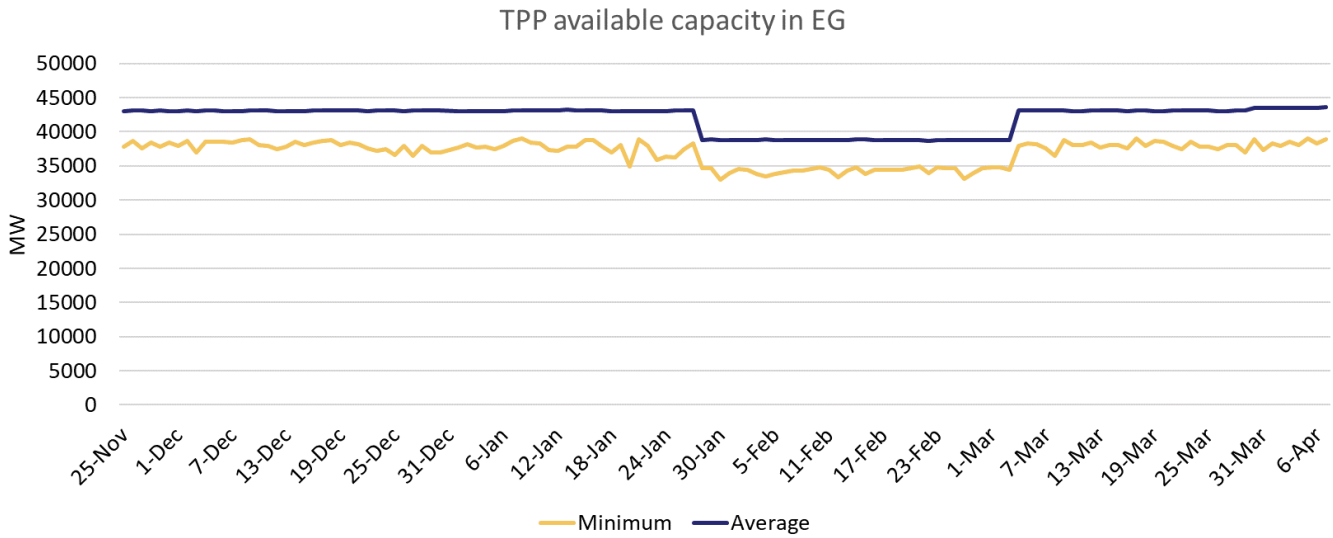


Figure 19 Installed Capacity mix with total NGC, import NTC and peak demand in Egypt.

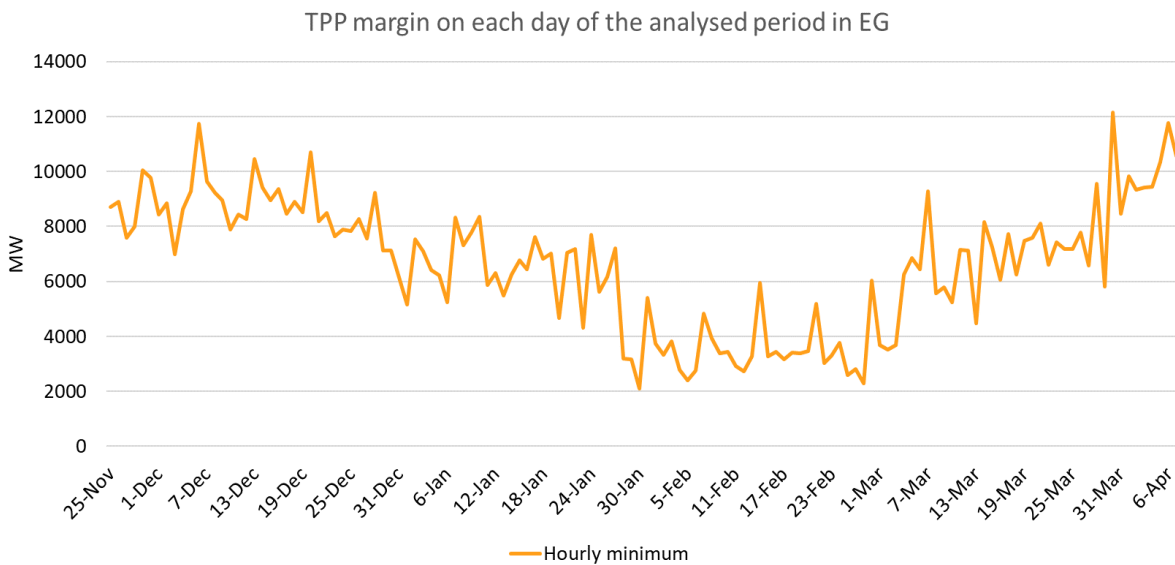
The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 20. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Egyptian average available TPP capacity fluctuates in this period due to planned and forced outages, there is also a reduced capacity of TPPs during February (derating factor of 10%). The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates around 36 GW.



**Figure 20 Average and minimum TPP available capacity among of all simulated MC years in Egypt.**

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is calculated and depicted in Figure 21. It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 7 GW and 16.5 GW during the analyzed winter season.

A very high TPP capacity margin indicates that Egypt will not have adequacy issues during the following season and that it has huge export capabilities that can bring benefit to neighboring countries' adequacy situation.



**Figure 21 Minimum hourly TPP margin on each day of the analyzed among of all simulated MC years period in Egypt.**

## ADEQUACY ASSESSMENT

No adequacy concerns are detected for both analyzed modes of operation in the case of Egypt.

## 5.2 Jordan

### DEMAND

Jordan's winter seasonal weekly demand, depicted in Figure 22, goes from around 442 GWh to 504 GWh (fluctuation at the level of 12%), while peak hourly demand in each week goes from 3927 MW to 4824 MW which presents even higher fluctuation – 18%. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

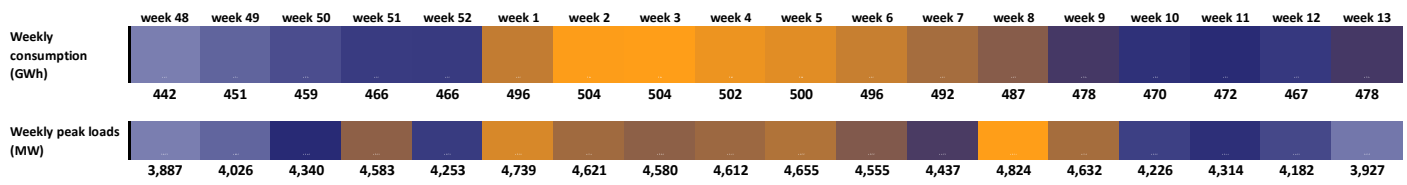


Figure 22 Seasonal Weekly demand in Jordan.



### SUPPLY AND NETWORK OVERVIEW

Jordan's power generation fleet is dominantly based on gas fueled TPPs, with the share in total installed capacities around 57%, which is divided further into conventional and OCGT TPPs. Oil share amounts to 6% of installed capacities, while RES wind and solar share in installed capacities are 8% and 29% respectively. Total installed capacities amount to 7580 MW with an import capacity up to 450 MW from Egypt.

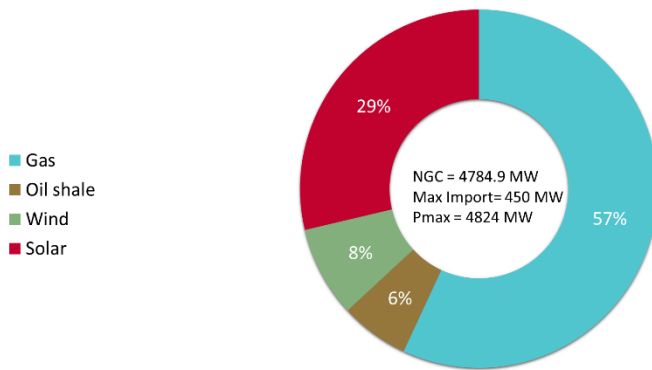
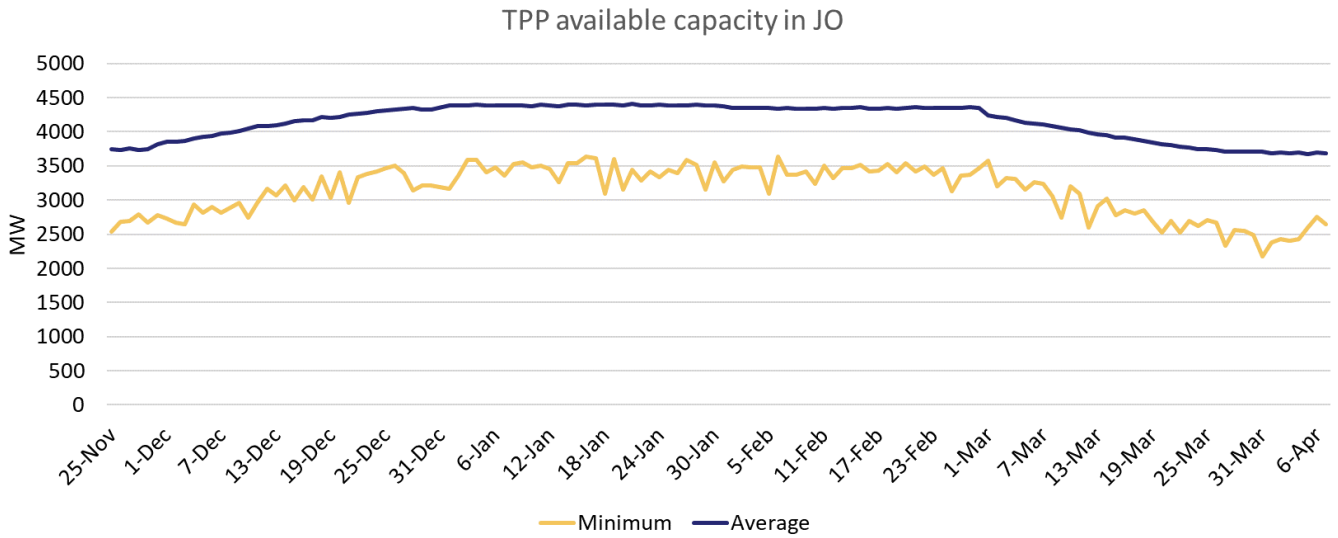


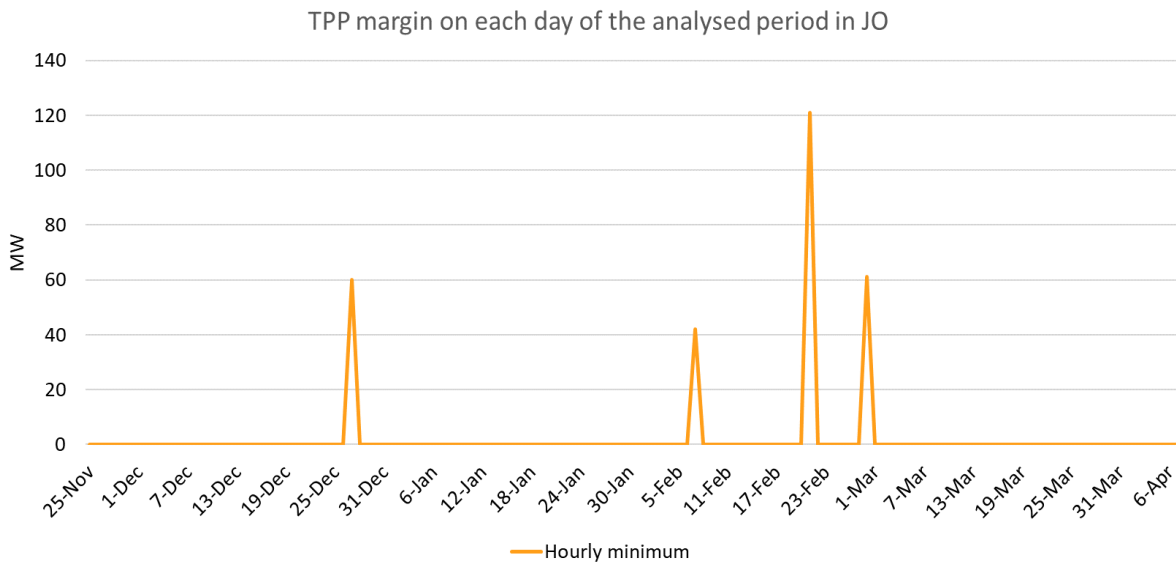
Figure 23 Installed Capacity mix with total NGC, import NTC and peak demand in Jordan.

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages is shown in Figure 24. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. The average available TPP capacities among all simulated MC years start from 3686 MW and rise to 4400 MW in early Jan due to maintenance stops aimed at ensuring sufficient capacity to meet winter demand and drop to 3667 MW mid of March of 2025. The minimal average daily available TPP capacity among all simulated MC years goes from 2170 MW to only 3600 MW.



**Figure 24 Average and minimum TPP available capacity among of all simulated MC years in Jordan.**

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is calculated and depicted Figure 25 It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin is often at zero value most of winter season. These results point to the fact that there is a possibility that during some hours adequacy can be endangered. Notably, the daily margin follows daily consumption patterns, and it is the lowest during working days, due to higher demand.

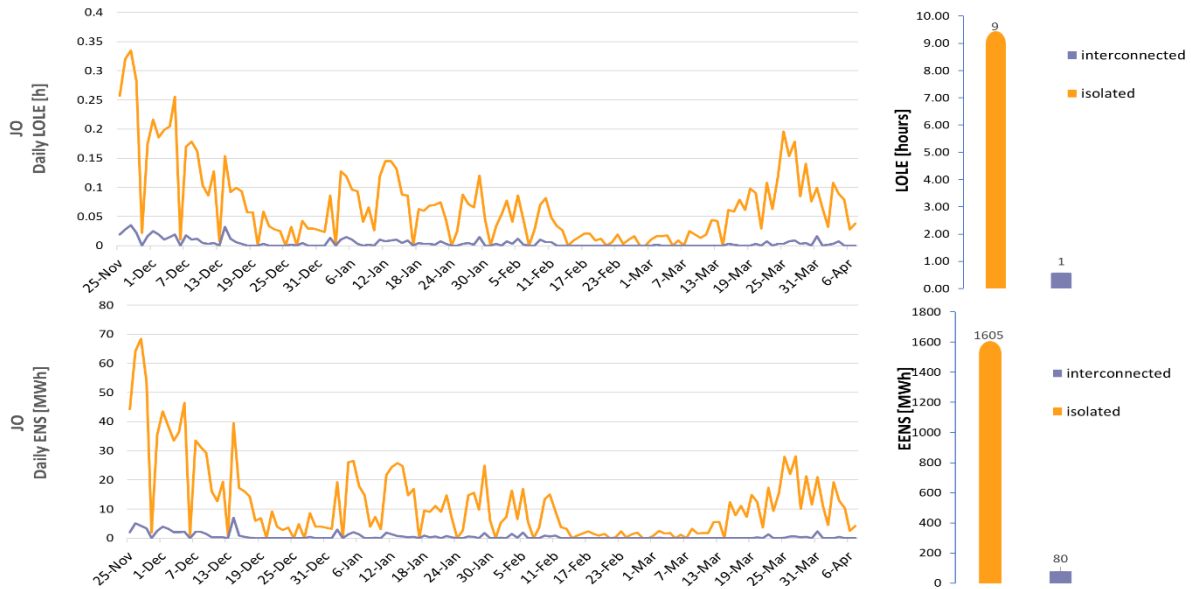


**Figure 25 Minimum hourly TPP margin on each day of the analyzed among of all simulated MC years period in Jordan.**

## ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 26, for both modes of operation – interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

The conclusion is that for both modes of operation adequacy risk is marginal, although for the theoretical isolated scenario adequacy risk is higher.



**Figure 26 Daily LOLE and EENS for the interconnected and isolated mode of operation in Jordan.**

At the right-hand part of the figure, LOLE and EENS for the entire season for both modes of system operation are given. Interconnections substantially reduce already small seasonal LOLE from 9 h to less than 1 h and expected winter seasonal EENS from 1605 MWh to just 80 MWh.

## 5.3 Lebanon

### DEMAND

Lebanon's winter seasonal weekly demand, depicted in Figure 27, goes from around 412 GWh to 480 GWh, while peak hourly demand each week goes from 3469 MW to 5153 MW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected during the first weeks of 2025, due to low temperatures and increased heating demand. The maximum hourly demand of 5153 MW is reached in the 6th week of 2025.

It should be noted that the operation of Lebanon's power system is especially difficult, with a continuous lack of supply and organized regular load shedding.

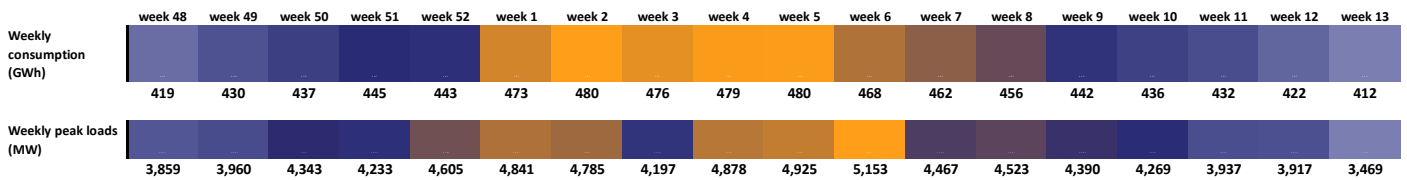


Figure 27 Seasonal Weekly demand in Lebanon.



### SUPPLY AND NETWORK OVERVIEW

Lebanon's power generation fleet is exclusively oil fueled, with the share in total installed capacities around 62% and 6% goes to hydro power plants & rest of 32% goes to solar rooftop capacities. Total installed capacities amount to 4696 MW, but as serious support to system operation, also the additional capacity of 1000 MW in diesel units is considered in this analysis.

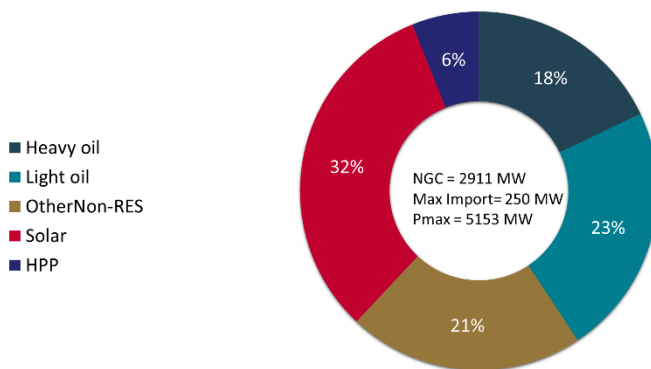
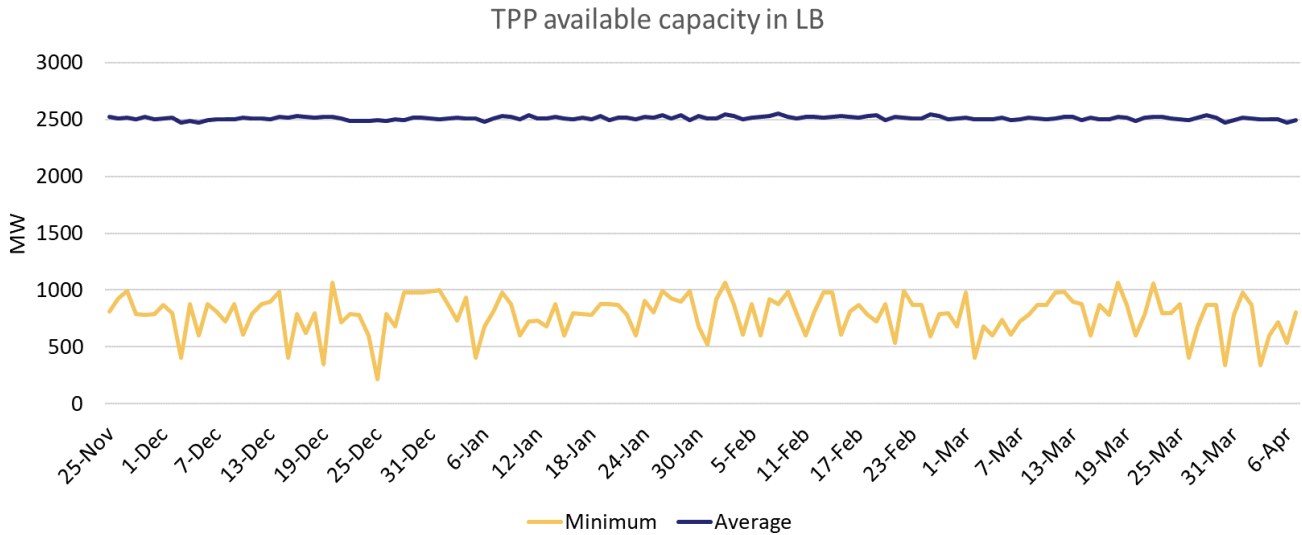


Figure 28 Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 29. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation.

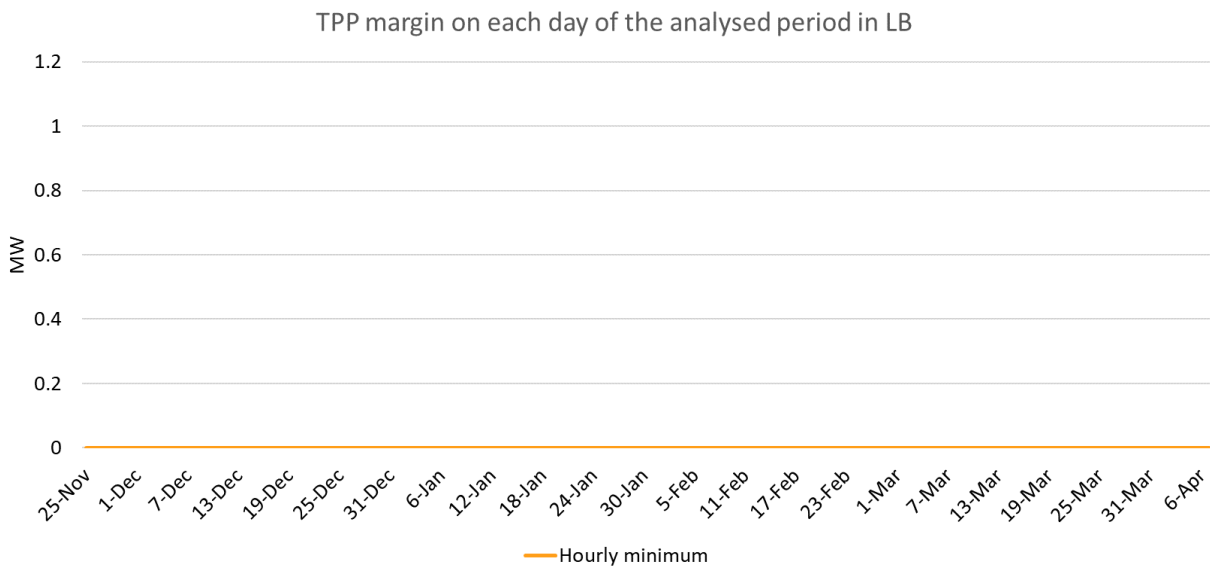
It should be noted that the total NGC in Lebanon is lower than the maximum expected hourly demand which points to a difficult system operation and dependence on import.

The average daily available TPP capacity among all simulated MC years is around only 2500 MW.



**Figure 29 Average and minimum TPP available capacity among of all simulated MC years in Lebanon.**

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is calculated and depicted in Figure 30. It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon’s power system.



**Figure 30 Minimum hourly TPP margin on each day of the analyzed period among of all simulated MC years in Lebanon.**

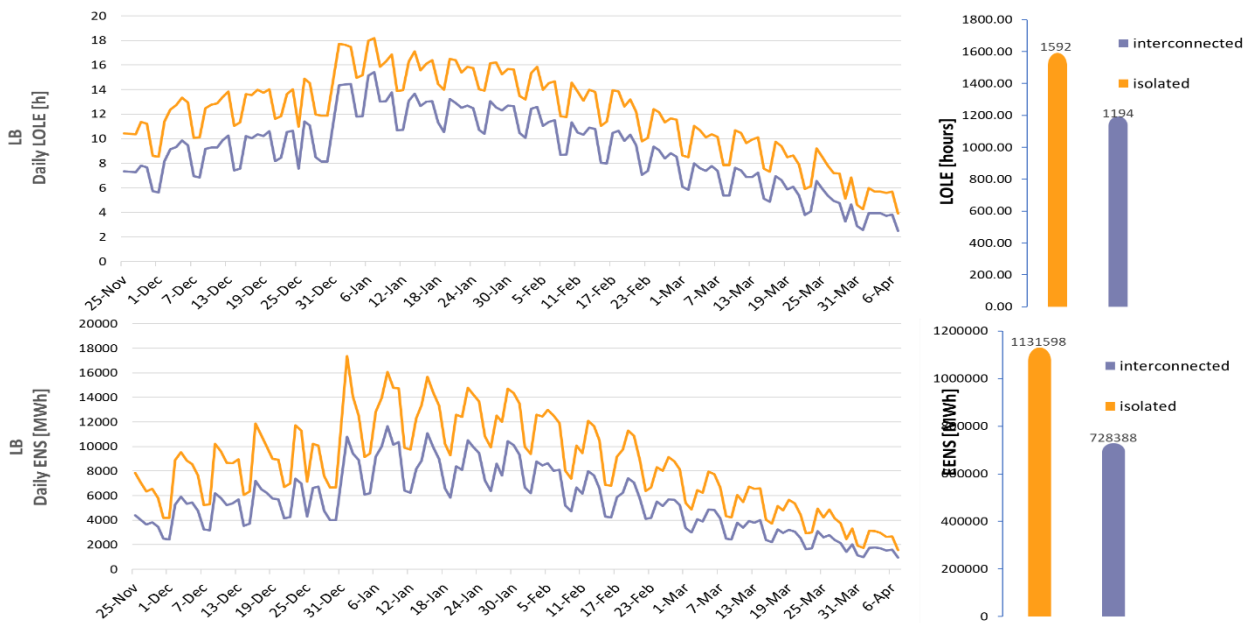
## ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in **Figure 31** for both modes of operation – hypothetical interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

The first conclusion is that the operation of this power system is not comparable with any other in this region. The number of hours with difficulties in supplying the load is so high that load shedding presents the regular, everyday action planned in advance.

Results of the simulations point to the fact that LOLE and ENS are above all acceptable values even in the hypothetical interconnected mode of operation: EENS is 728 GWh and LOLE is 1194 hours (around 39 % during the winter season of 3024 hours). There are climatic years without adequacy issues, but there is no day without adequacy issues in all 684 analyzed MC years.

Looking at the whole season, even in the best case, everyday there are adequacy issues: LOLE Min=2 hours and LOLE Max=15 hours in average of 684 MC years.



**Figure 31 Daily LOLE and EENS for the interconnected and isolated mode of operation In Lebanon**

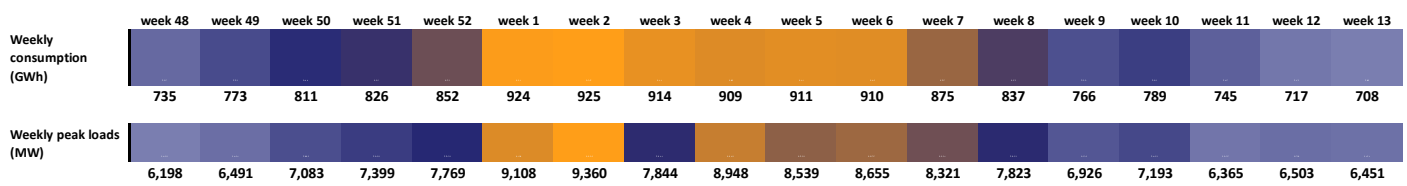
In the case of isolated operating mode, LOLE and EENS are even higher. hypothetical Interconnection with Jordan helps but cannot solve all adequacy issues.

## 5.4 Libya

### DEMAND

Libya's winter seasonal weekly demand, depicted in **Figure 32**, goes from around 708 GWh to 925 GWh, while peak hourly demand each week goes from 6198 MW to 9360 MW. This variation of the peak load is almost 33% which is very high. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected in January (2<sup>nd</sup> week) 2025. The maximum hourly demand in all 38 MC years reaches 9360 MW in the week 2<sup>nd</sup> of 2025.

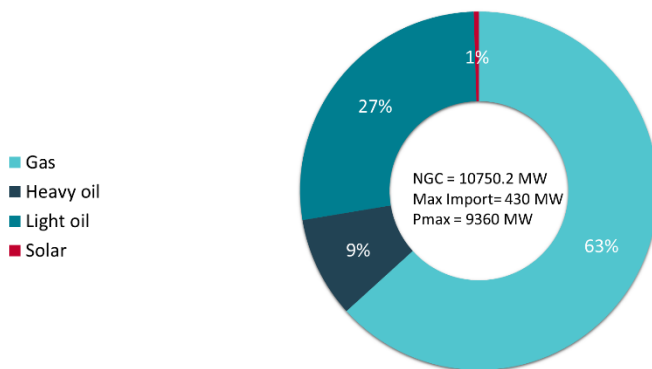


**Figure 32 Seasonal Weekly demand in Libya.**



### SUPPLY AND NETWORK OVERVIEW

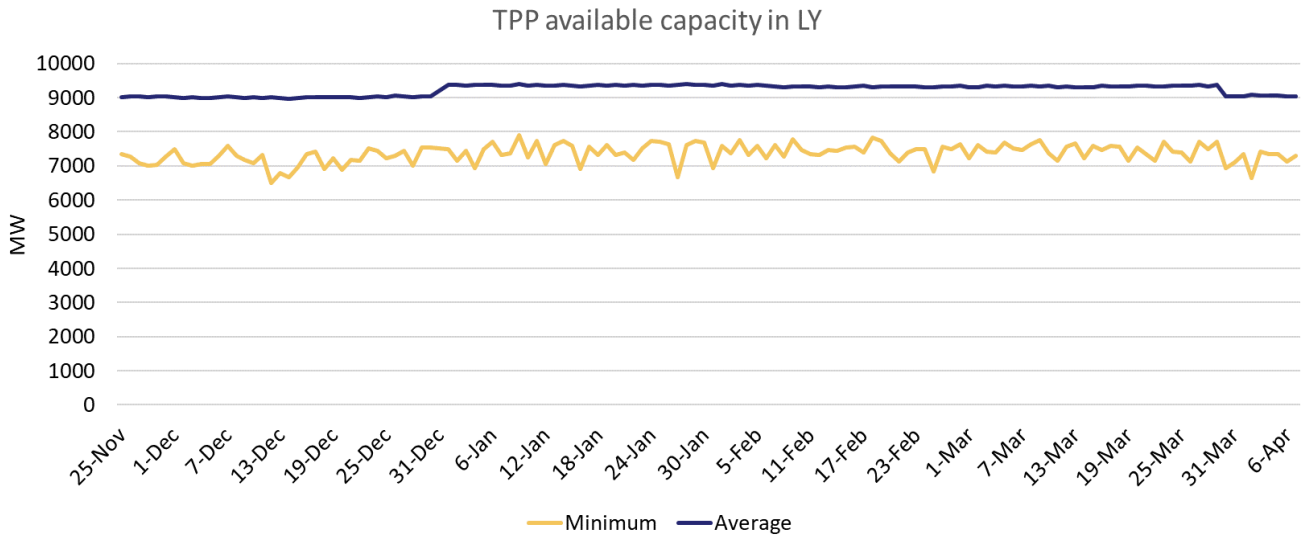
Libya's generation portfolio is based exclusively on gas-fired power plants, with 99% in generation capacity mix. The majority of installed thermal capacities refer to gas turbines (63%) and light oil (27%), while only 9% of capacities of heavy oil. It should be emphasized that according to provided data for winter outlook 2024/2025 we consider 50 MW rooftop solar capacities installed in Libya.



**Figure 33 Installed Capacity mix with total NGC, import NTC and peak demand in Libya.**

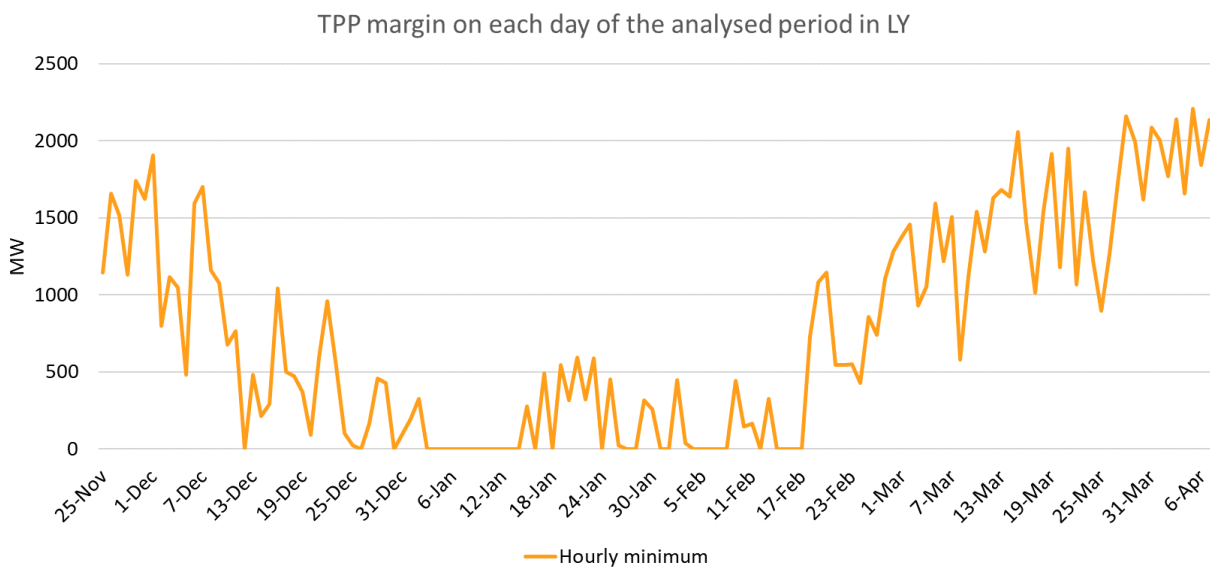
The average daily available TPP capacity, after reduction due to forced outages, is shown **Figure 34**. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Libya's average available thermal capacity is stable at the level of 9000 MW.

The minimal daily available TPP capacity between all analyzed MC years is between 6500 MW to 8000 MW.



**Figure 34 Average and minimum TPP available capacity among of all simulated MC years in Libya.**

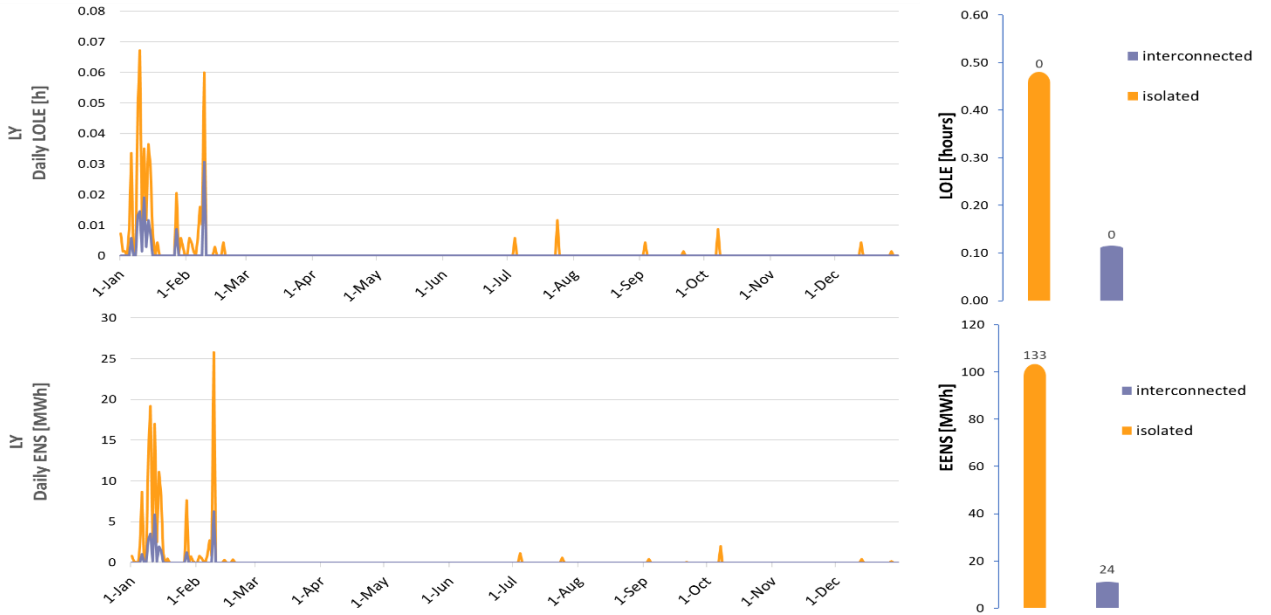
As a result of system simulation, the minimum hourly TPP margin among all simulated MC years for each day is calculated and depicted **Figure 35**. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on some days is at zero. Rest of the days with non/zero minimum daily margin, which are noted at the beginning and end of the winter season.



**Figure 35 Minimum hourly TPP margin on each day of the analyzed period among of all simulated MC years in Libya.**

## ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 36, for the interconnected and isolated mode of operation. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted. The conclusion is that for both modes of operation adequacy risk is marginal.



**Figure 36 Daily LOLE and EENS for the interconnected and isolated mode of operation in Libya.**

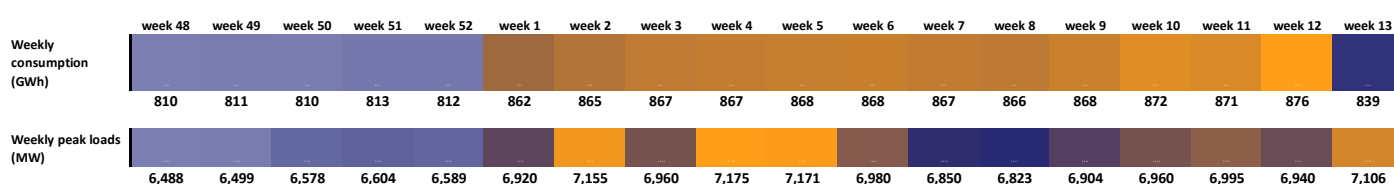
At the right-hand part of the figure, LOLE and EENS for the entire season for the interconnected and isolated mode of system operation are given. LOLE for the entire season in the isolated case is minor, while for the interconnected regime of operation seasonal LOLE is significantly lower.

## 5.5 Morocco

### DEMAND

Moroccan winter seasonal weekly demand, depicted in **Figure 37** goes from around 810 GWh to 976 GWh, while peak hourly demand each week goes from 6488 MW to 7175 MW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected from January to March and it's pretty much constant, while the maximum hourly demand in all 38 MC years reaches 6950 MW in the 34<sup>th</sup> week.

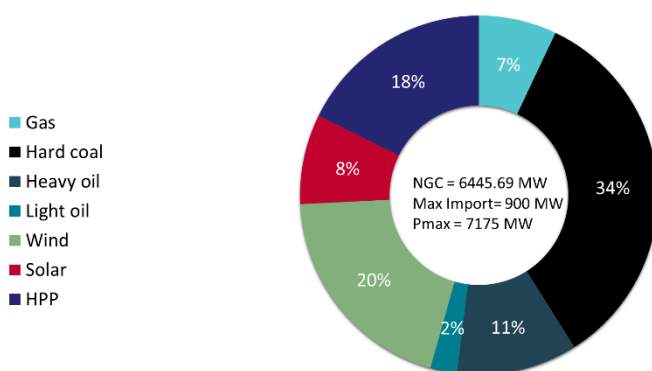


**Figure 37 Seasonal Weekly demand in Morocco.**



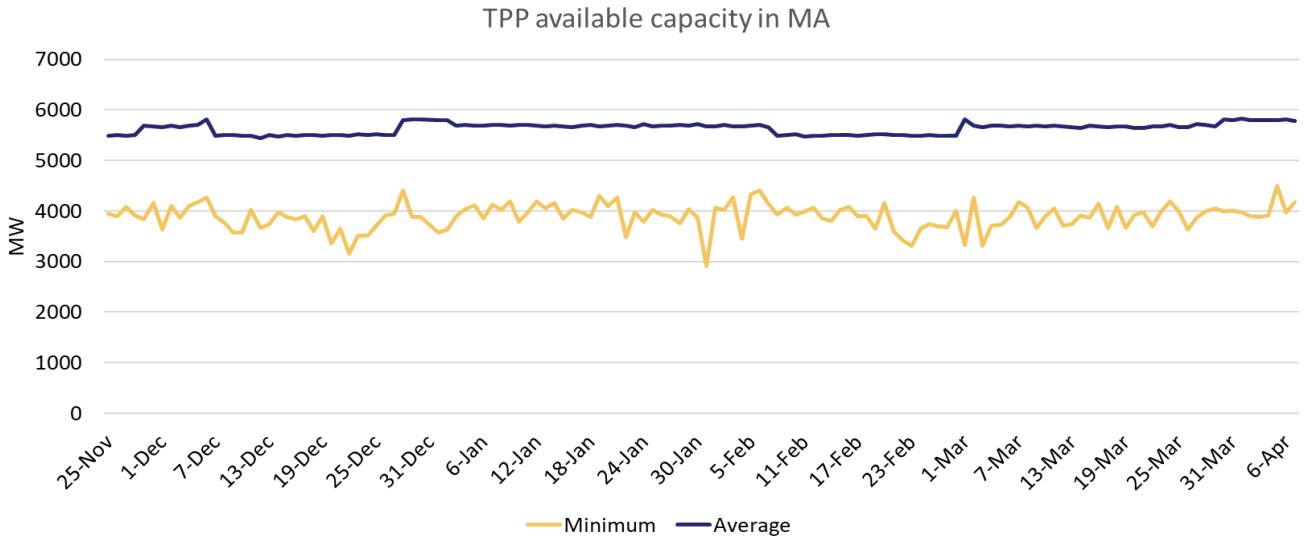
### SUPPLY AND NETWORK OVERVIEW

Moroccan power generation fleet is balanced and well-diversified in comparison with other analyzed countries, with the TPP share in total installed capacities around 54%, which is divided further into Coal, Gas and Oil TPPs. Hydro capacities amount to 18%, while RES wind and solar share in installed capacities is 20% and 8% respectively. Total installed capacities are 11852.69 MW with total import capacity up to 900 MW, which is about 12.5% of peak load in the analyzed period.



**Figure 38 Seasonal Weekly demand in Morocco.**

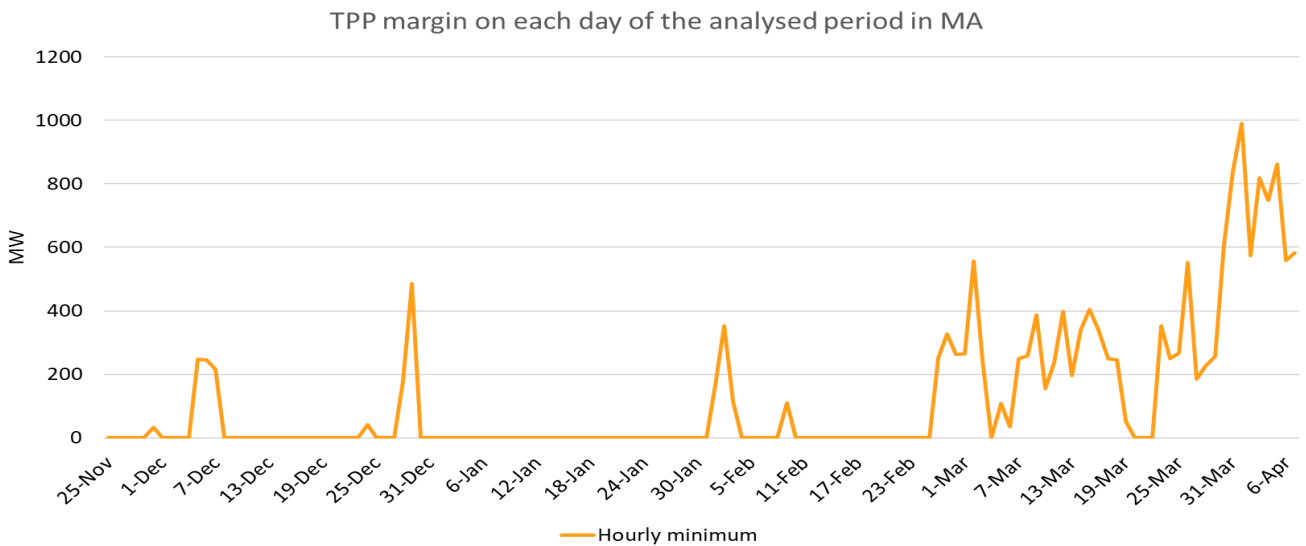
The average daily available TPP capacity, after reduction due to forced outages, is shown **Figure 39**. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Moroccan average available TPP capacities among of all simulated MC years level is stable, and it is around 5304 MW. It should be noted that fluctuations in the average curve are due to the planned outage schedule.



**Figure 39 Average and minimum TPP available capacity among of all simulated MC years in Morocco.**

As a result of system simulation, the minimum hourly TPP capacity margin among of all simulated MC years on each day is calculated and depicted in Figure 40. It represents the difference between available and engaged TPP capacities. The minimum hourly value of the TPP margin is often at zero value most of winter season. These results point to the fact that there is a possibility that during some hours adequacy can be endangered however, with the support of interconnections, the system remains stable.

Notably, the daily margin follows daily consumption patterns, and it is the lowest during working days, due to higher demand.

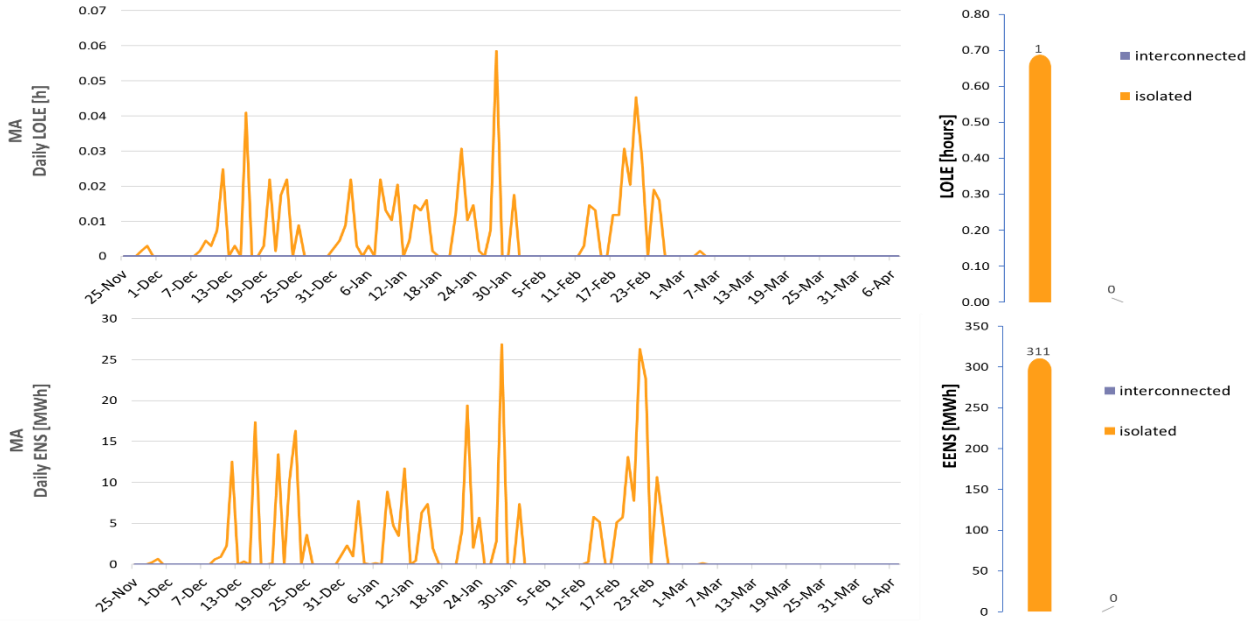


**Figure 40 Minimum hourly TPP margin on each day of the analyzed period in Morocco.**

## ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 41 for the interconnected and isolated mode of operation. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted. It can be seen that there is no adequacy risk in the winter period of 2024/2025 in Morocco.

No adequacy risks are present in the Isolated & interconnected mode of operation.



**Figure 41 Daily LOLE and EENS for the interconnected and isolated mode of operation in Morocco.**

At the right-hand part of the figure, LOLE and EENS for the entire season for the isolated mode of system operation are given. LOLE for the entire season is about 1 hours, while EENS is around 311 MWh.

## 5.6 Tunisia

### DEMAND

Tunisian seasonal weekly demand, depicted in Figure 42 ranges between 330 GWh and 395 GWh, while peak hourly demand each week goes from 2914 MW to 3486 MW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected during from the end of December to the end of February. The maximum hourly demand is reached in the 5th week - 3486 MW, which is the maximum in all 38 climatic years.

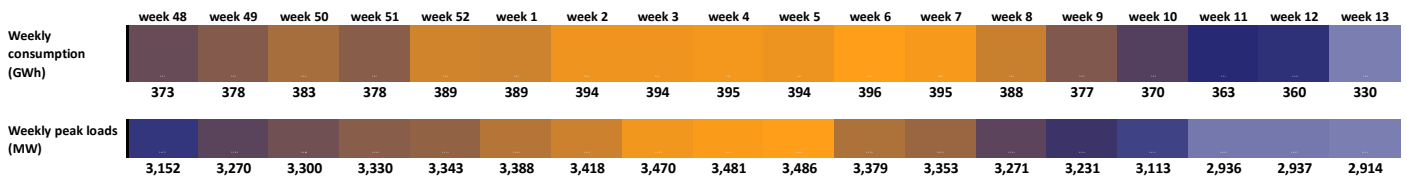


Figure 42 Seasonal Weekly demand in Tunisia.



### SUPPLY AND NETWORK OVERVIEW

Tunisian power generation fleet is almost exclusively gas fired, with the share in total installed capacities around 90%, which is divided further into conventional, CCGT and OCGT TPPs. RES, i.e. wind and solar share in installed capacities is only around 10%. Total installed capacities amount to 5770 MW with import capacity up to 800 MW, while maximum hourly consumption is around 3486 MW.

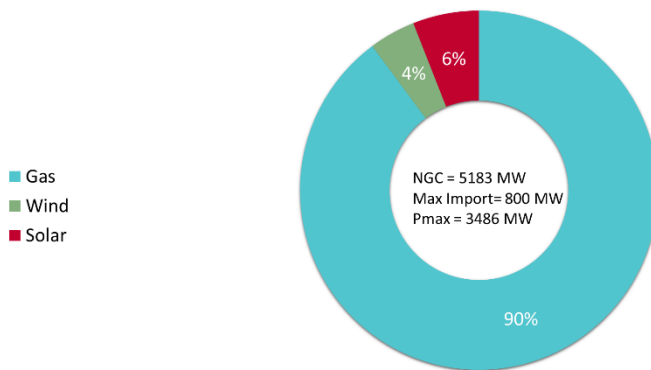
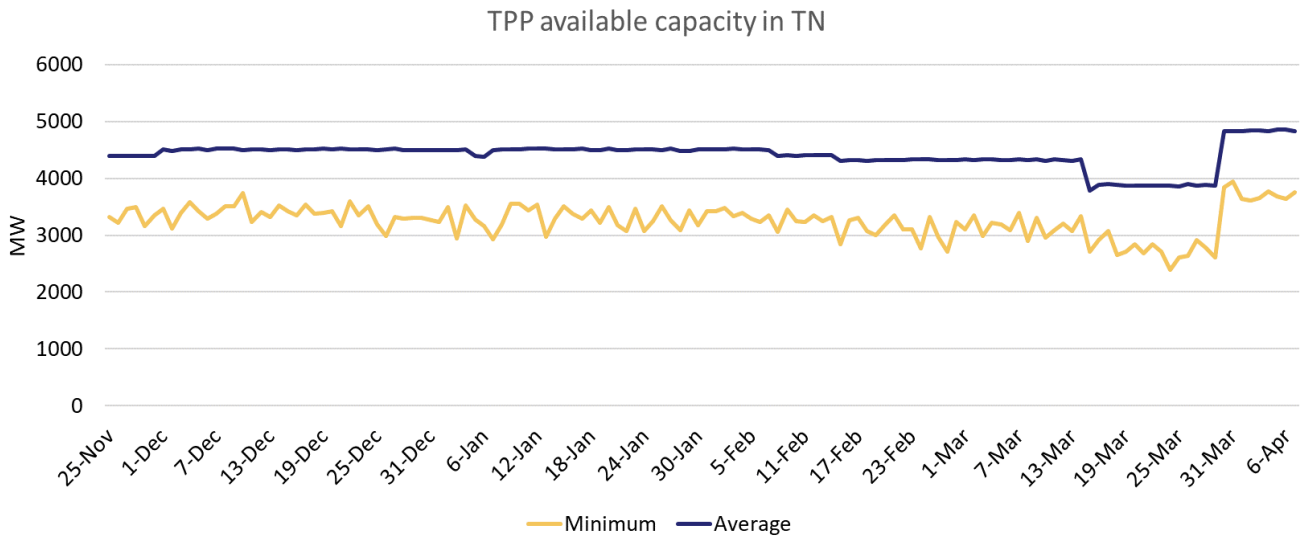


Figure 43 Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia.

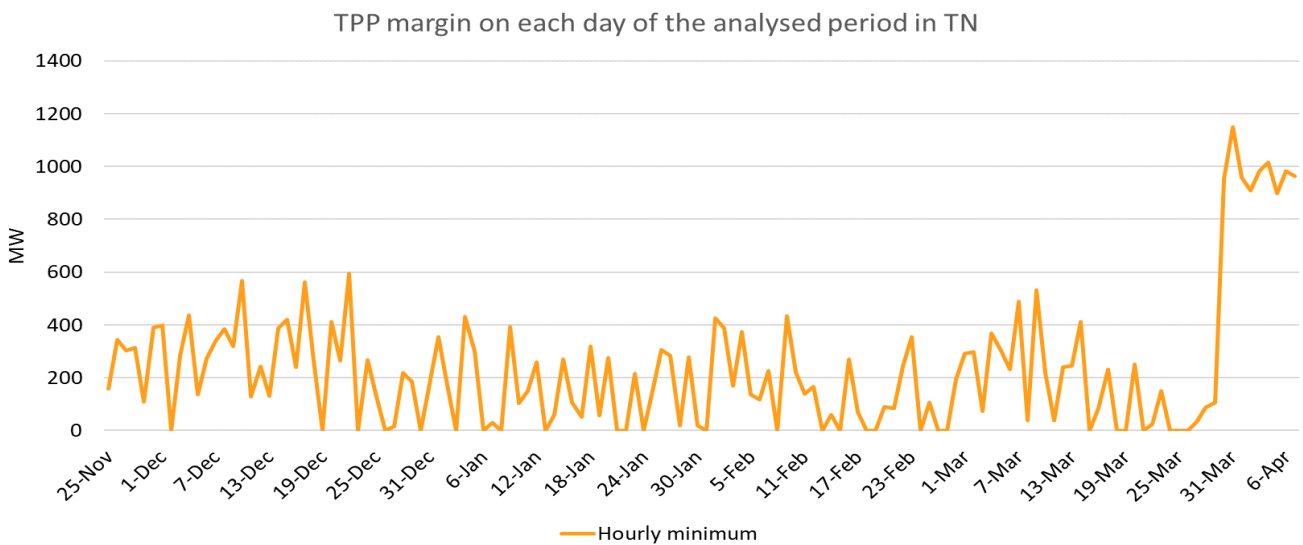
The average daily available TPP capacity, after reduction due to forced outages is shown in Figure 44 Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. The average available thermal capacity, across all 684 MC years, is approximately 4,500 MW, dropping to 3,870 MW in the second half of March before rising again to 4,840 MW after the winter season. This is above the expected peak load of 3,486 MW during the winter. 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 2,388 MW.



**Figure 44 Average and minimum TPP available capacity among of all simulated MC years in Tunisia**

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 45. It represents the difference between available and activated TPP capacities. It can be seen that the minimum hourly margin is always higher than zero (except for some days during winter season).

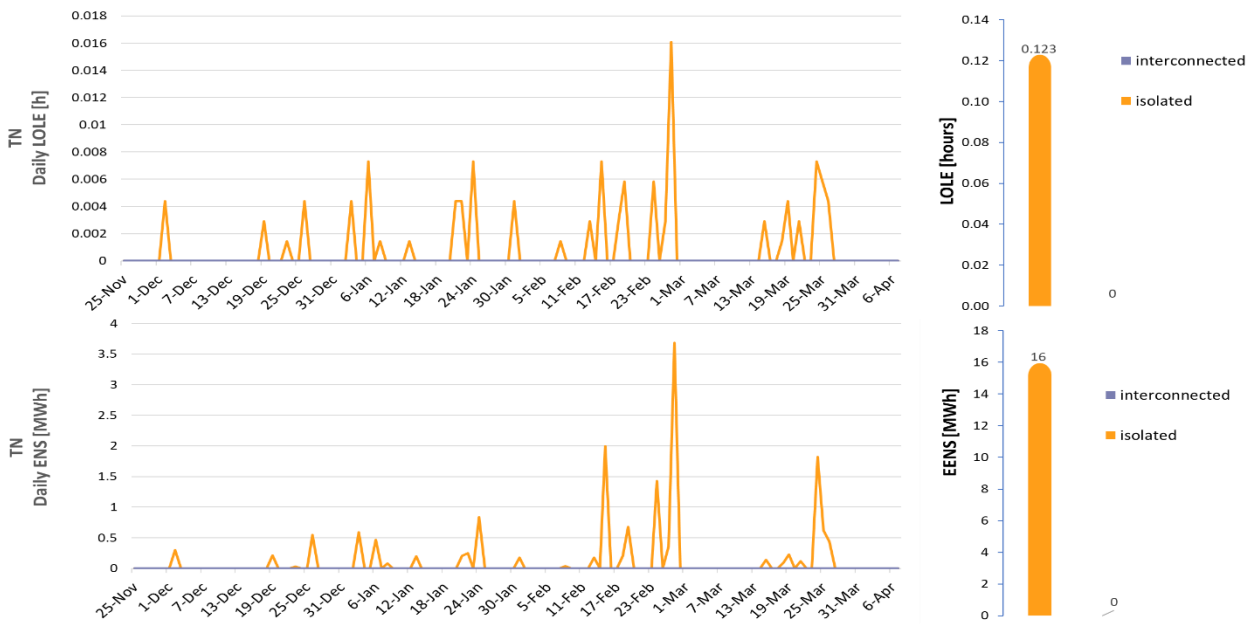


**Figure 45 Minimum hourly TPP margin on each day of the analyzed period in Tunisia.**

## ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in **Figure 46** for both modes of operation – interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

The first conclusion is that there is no adequacy risk in Tunisia for the interconnected regime of operation, while in isolated case adequacy risk is very low during the whole season, with daily LOLE lower than 0.123 hour. In fact, only in a few days, there is a lack of energy, always below 16 MWh.



**Figure 46 Daily LOLE and EENS for the interconnected and isolated mode of operation.**

## 6 Sensitivity Cases

In our previous analysis, we presented the adequacy situation based on a probabilistic approach, which averaged data from all 38 analyzed climatic years repeated 18 times to ensure good convergence of results as discussed in page 23. However, as we further explore the winter outlook adequacy situation, we recognize the need to pinpoint the most severe Monte Carlo Climatic Year (MCY) within this dataset. This exploration aims to uncover extreme scenarios that may challenge the resilience of energy systems in each country.

### Interconnected Operation:

This scenario explores the operation of the analyzed countries under the same interconnected grids mentioned in Page 21, where they can exchange electricity only if adequacy risk is identified.

### Isolated Operation:

In contrast, this scenario investigates the operation of the analyzed countries in isolation, where each country operates independently without interconnections. Isolated operation poses challenges to energy security, especially during peak demand.

### 6.1 The Most severe Monte Carlo Climatic Year

To identify the most severe MCY from all 684 MC years of our analyzes, we start from the 38 unique climatic years that we have (from period 1982 to 2019) then we average all MCY that shares the same climatic year. Finally, we identify the most severe MCY among them.

In the case of a theoretical isolated scenario (

Figure 47) shows the winter season only, adequacy risks are observed in Libya, Jordan & Lebanon, although they could be considered low & medium risk in Libya & Jordan while for Lebanon adequacy risk is very high under isolated system operating mode.

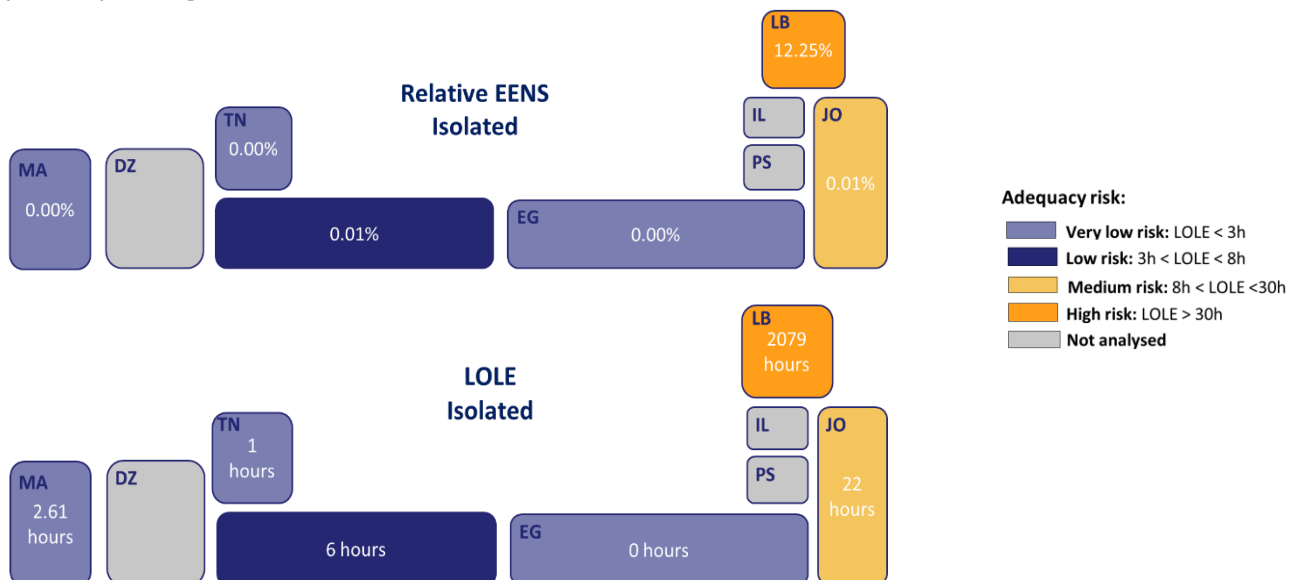
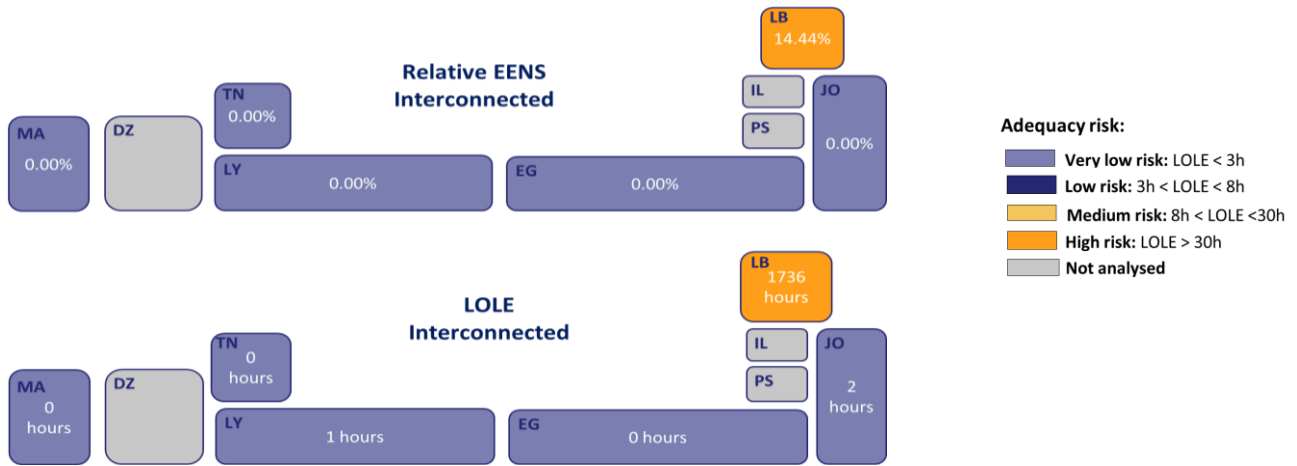


Figure 47 Seasonal Relative EENS and LOLE for the isolated mode of operation for the most severe MCY for winter season.

Interconnections and energy exchanges needed to overcome adequacy issue with neighboring countries reduce adequacy risks to very low risk in the case of Libya & Jordan but, in Lebanon even in this more relaxed operating mode, adequacy risks are at an unacceptable level (

Figure 48)<sup>6</sup> shows interconnected scenario for the winter season only.

<sup>6</sup> Color coding of adequacy risk levels presented in



**Figure 48 Seasonal relative ENS and LOLE for the interconnected mode of operation for the most severe MCY for winter season.**

The figures clearly show that interconnection is critical in reducing the impact of the most severe Monte Carlo Climatic Year (MCY) for Libya, and Jordan. However, despite the hypothetical interconnection with Jordan, Lebanon remains at high risk for the upcoming Winter Outlook 2024/2025.

Figure 48 & Figure 48 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.



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