TeasiMed

TOWARDS AN EFFICIENT, ADEQUATE, SUSTAINABLE AND
INTERCONNECTED MEDITERRANEAN POWER SYSTEM

SEASONAL ADEQUACY ASSESSMENT
Winter Outlook 2022/23

Detailed Report

Released on 09.12.2022

med-TSO
MEDITERRANEAN TRANSMISSION SYSTEM OPERATORS

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Abbreviations

CCGT – Combine Cycle Gas Turbine

EKC – Electricity Coordinating Center

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)

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

PS - Palestine

LB - Lebanon

ES - Spain

1 Executive Summary

This Report presents the adequacy situation among non-EU Med-TSO members during this winter (2022/2023). With this assessment, Med-TSO is aligning with the world-wide best practice and the latest development of the EU regulations[1] . 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.

This Winter Outlook 2022/2023 Report provides information about potential adequacy issues during winter period 2022/2023 in 7 MED-TSO members: Morocco, Algeria, Tunisia, Libya, Egypt, Jordan and Lebanon.

Main adequacy indicators that have been assessed are:

- **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected 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 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.

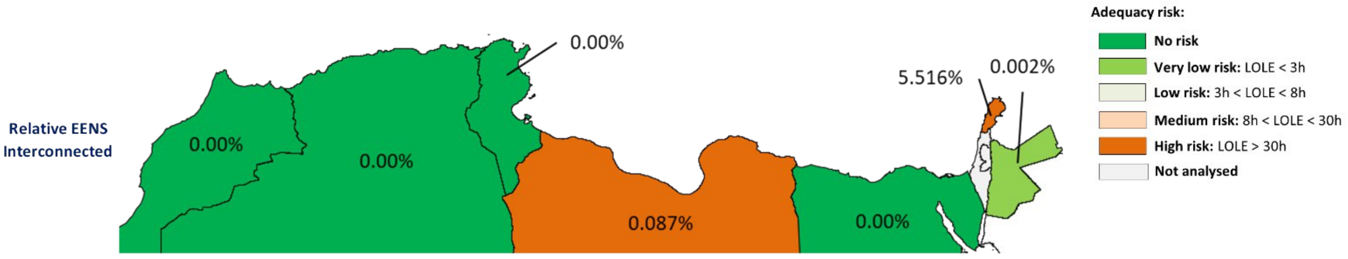

Figure 1: Seasonal relative ENS for interconnected mode of operation

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

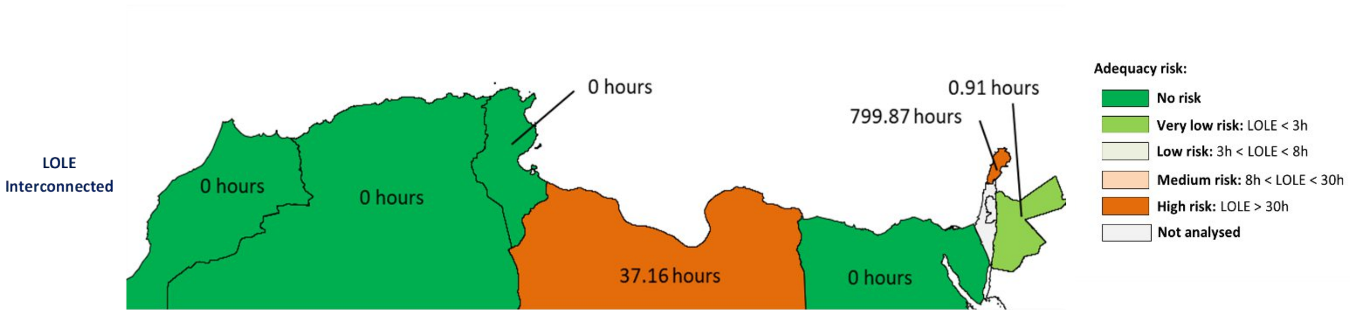


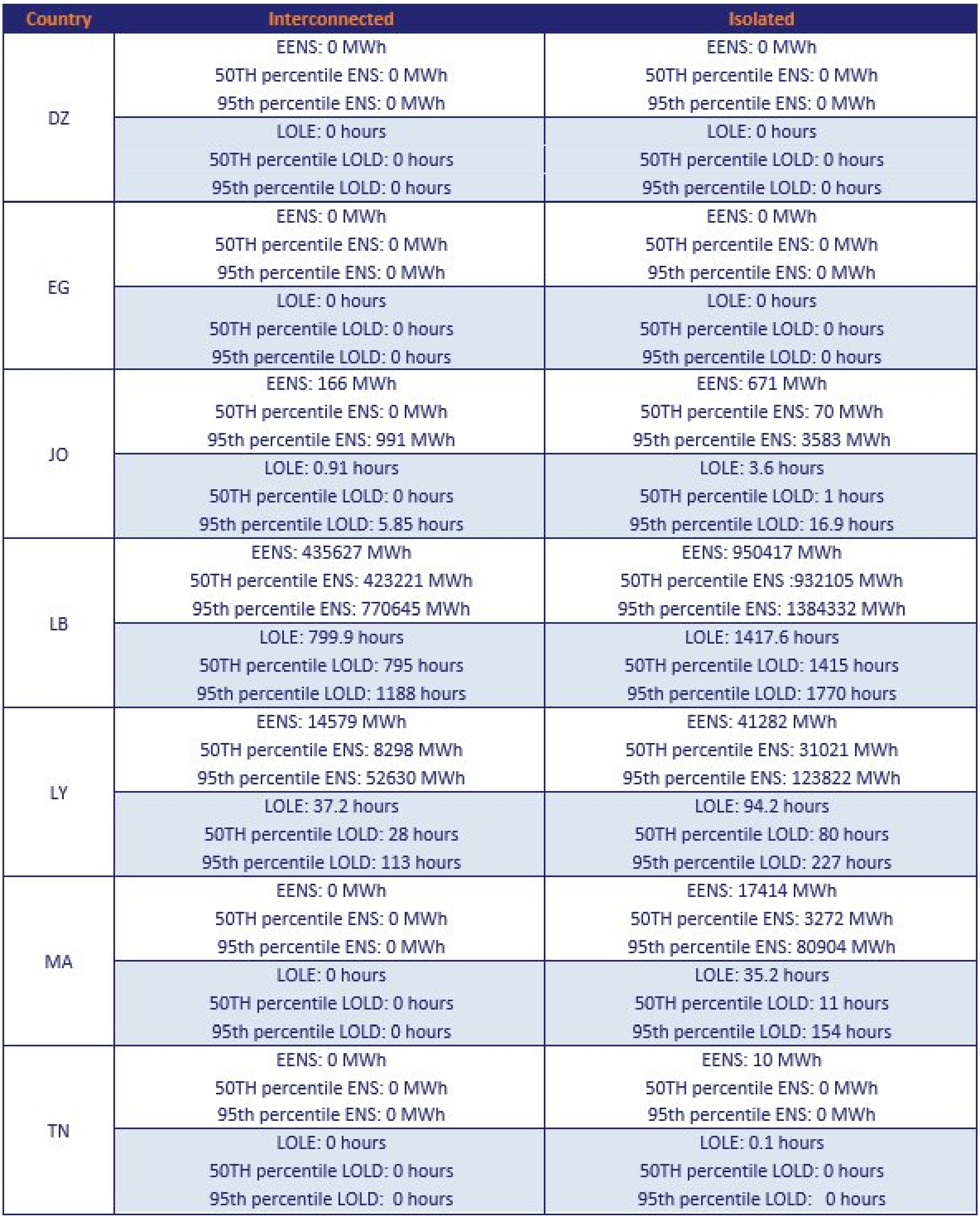
Figure 2: Seasonal LOLE for interconnected mode of operation

The conclusion is that during this winter the most severe adequacy issues may occur in case of Lebanon and Libya (see Figure 1 and Figure 2). The situation is more critical in case of Lebanon, where LOLE reaches around 800 hours and energy not supplied is higher than 5.5% of demand in observed winter period. On the other hand, very low adequacy risk was registered in Jordan (LOLE lower than 1 hour). The period when there is the highest probability that generation (+import) will not be sufficient to cover Libya's electricity demand are expected in November and December, while in the rest of the analyzed period the risk is lower, mainly due to commissioning of new thermal capacities. 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 Lebanon's power system is especially difficult, with a continuous lack of supply and organized regular load shedding.

It should be emphasized that in case of Lebanon and Libya even if all generation capacities are available, taking into account the maximum potential electricity imports from neighboring systems, electricity demand during peak hours of the observed period cannot be supplied. This conclusion is a consequence of provided input data (available generation capacities and forecasted level of demand during the winter period) and can be deduced without performing any adequacy simulation.

In the next tables annual ENS and LOLD results are given for all analysed countries.

Table 1: Seasonal ENS for Interconnected and isolated scenario



Country	Interconnected	Isolated
DZ	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours
EG	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours
JO	EENS: 166 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 991 MWh	EENS: 671 MWh 50TH percentile ENS: 70 MWh 95th percentile ENS: 3583 MWh
	LOLE: 0.91 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 5.85 hours	LOLE: 3.6 hours 50TH percentile LOLD: 1 hours 95th percentile LOLD: 16.9 hours
LB	EENS: 435627 MWh 50TH percentile ENS: 423221 MWh 95th percentile ENS: 770645 MWh	EENS: 950417 MWh 50TH percentile ENS :932105 MWh 95th percentile ENS: 1384332 MWh
	LOLE: 799.9 hours 50TH percentile LOLD: 795 hours 95th percentile LOLD: 1188 hours	LOLE: 1417.6 hours 50TH percentile LOLD: 1415 hours 95th percentile LOLD: 1770 hours
LY	EENS: 14579 MWh 50TH percentile ENS: 8298 MWh 95th percentile ENS: 52630 MWh	EENS: 41282 MWh 50TH percentile ENS: 31021 MWh 95th percentile ENS: 123822 MWh
	LOLE: 37.2 hours 50TH percentile LOLD: 28 hours 95th percentile LOLD: 113 hours	LOLE: 94.2 hours 50TH percentile LOLD: 80 hours 95th percentile LOLD: 227 hours
MA	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 17414 MWh 50TH percentile ENS: 3272 MWh 95th percentile ENS: 80904 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 35.2 hours 50TH percentile LOLD: 11 hours 95th percentile LOLD: 154 hours
TN	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 10 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 0.1 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours

2 Approach and methodology

2.1 Adequacy assessment methodology

This Report presents the adequacy situation among non-European Med-TSO members during winter 2022/2023. With this assessment, Med-TSO is aligning with the worldwide best practice and the latest development of the EU regulations[2].

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 decarbonise energy systems - adequacy monitoring becomes even more important.

This Winter Outlook 2022/23 Report provides information about potential adequacy issues during winter 2022/23 in the 7 MED-TSO members: Morocco, Algeria, Libya, Tunisia, Egypt, Jordan and Lebanon.

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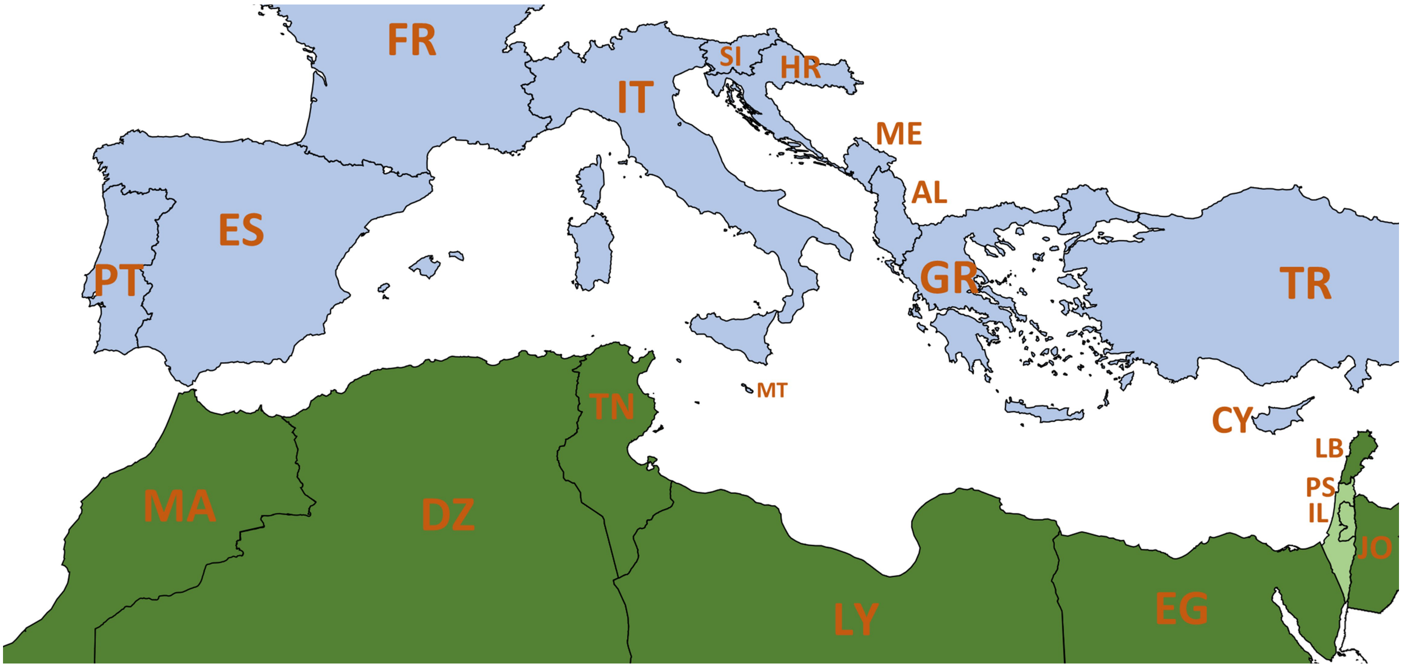
2 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en



🟩 Med-TSO members that is analysed in this adequacy assessment

🟩 Med-TSO members that is not analysed in this adequacy assessment

🟦 Med-TSO members taking part to the ENTSO-E adequacy study

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

Data for Israel and Palestine are not available at the moment.

The analysed period includes all hours between the beginning of week 48 in 2022 and the end of week 13 in 2023 which is the period between Saturday, November 26th and Saturday, April 4th.

The analyses have been carried out with the ANTARES simulator, 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 2020”;
- 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 six months 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 Med-TSO, 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 analysed timeframe. For all those MC years, hourly calculations are performed for the whole geographical scope.

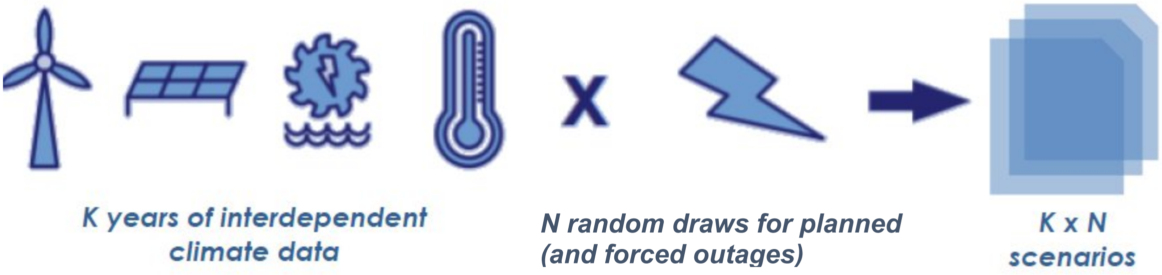


Figure 4: Probabilistic modelling general approach (source: ENTSO-E)

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
- **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.

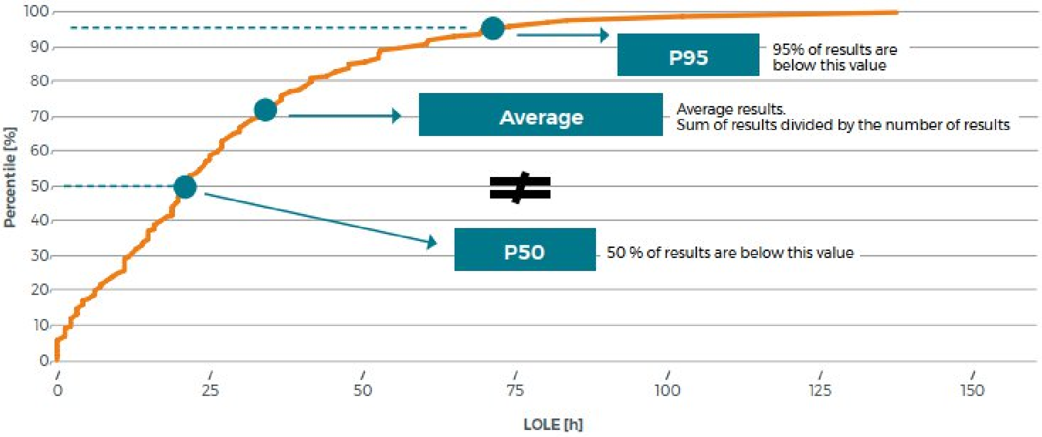


Figure 5: Illustrative Example of the relation between average, P50 and P95 values

- **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.

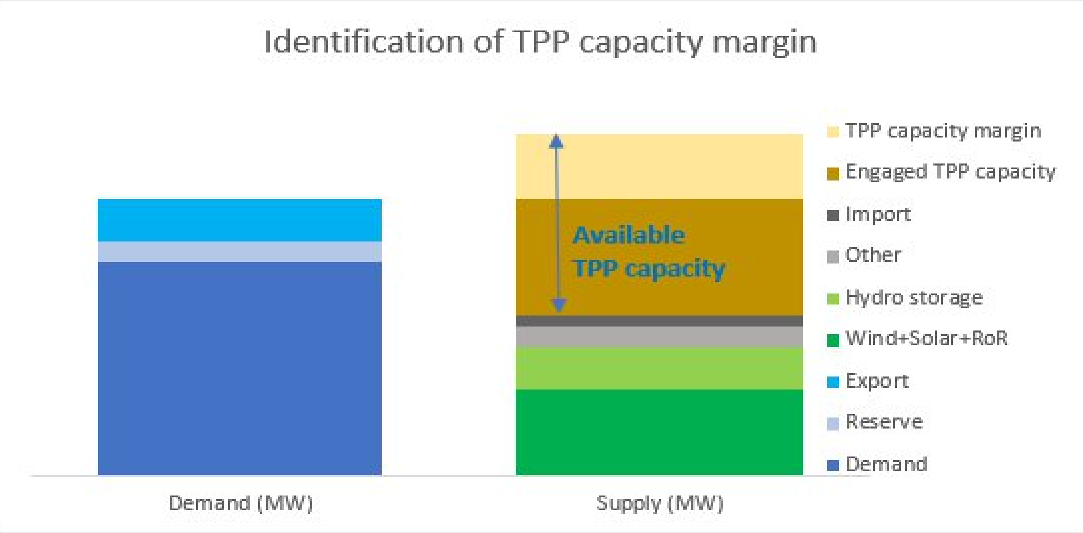


Figure 6: Illustrative Example of TPP capacity margin identification

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.

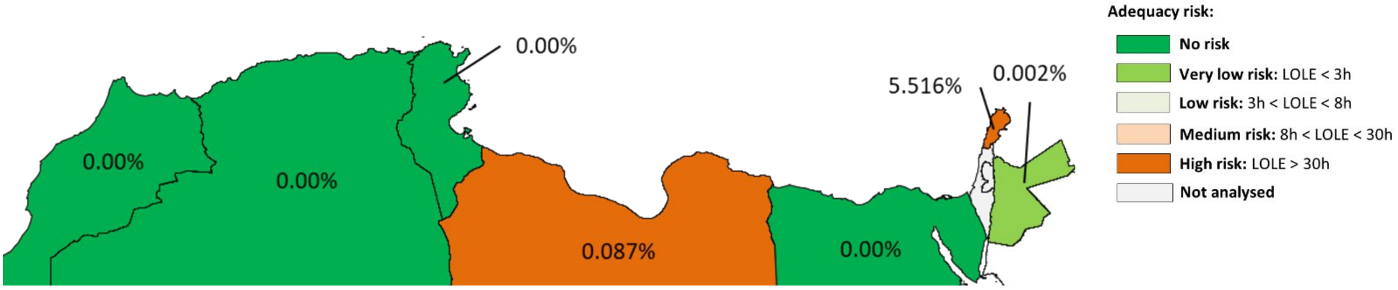


Figure 7: Illustrative Example of Spatial Screening result chart – Relative ENNS chart

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 8. This would allow the detection of which weeks are mostly at risk.

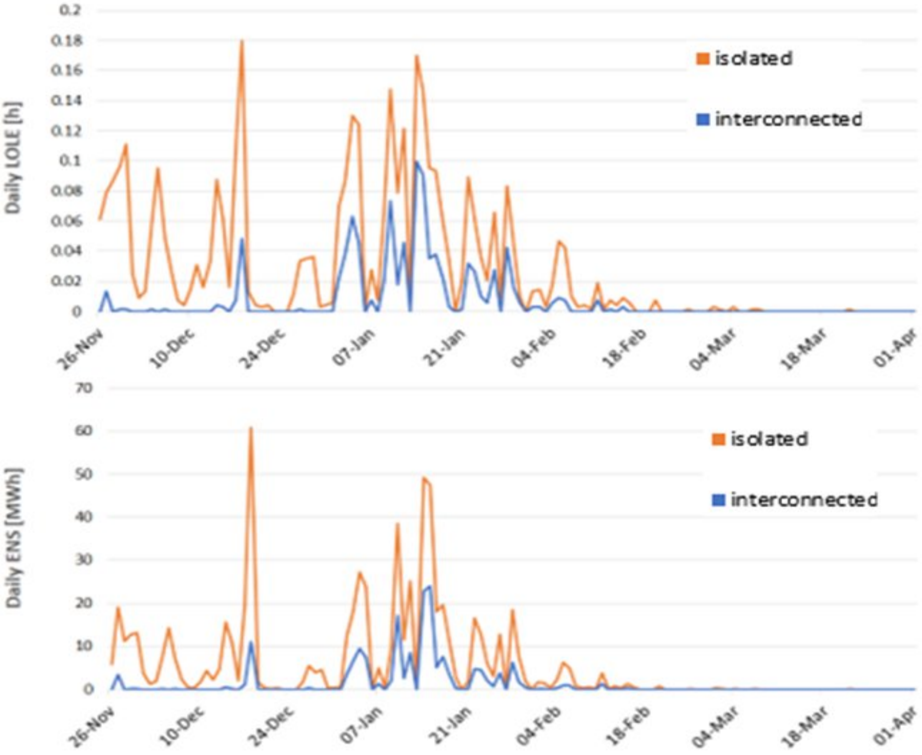


Figure 8: Illustrative example of average daily LOLE and EENS

In addition, available thermal capacities and thermal capacity margins are also presented at a daily level pointing to the excess of thermal capacities in cases when adequacy risks do not exist or pointing to the specific weeks when adequacy risks are at maximum.

In both cases, the average and minimum daily values of all simulated MC years are presented as given in the following figures.

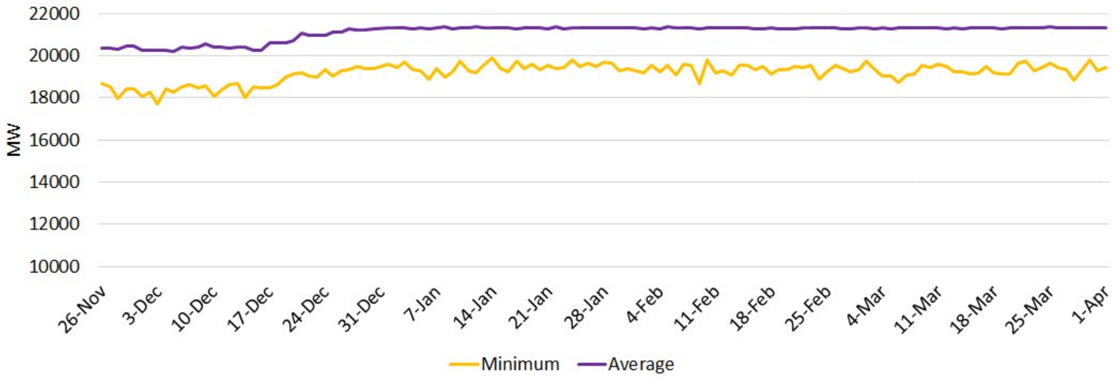


Figure 9: Illustrative example of available TPP capacity

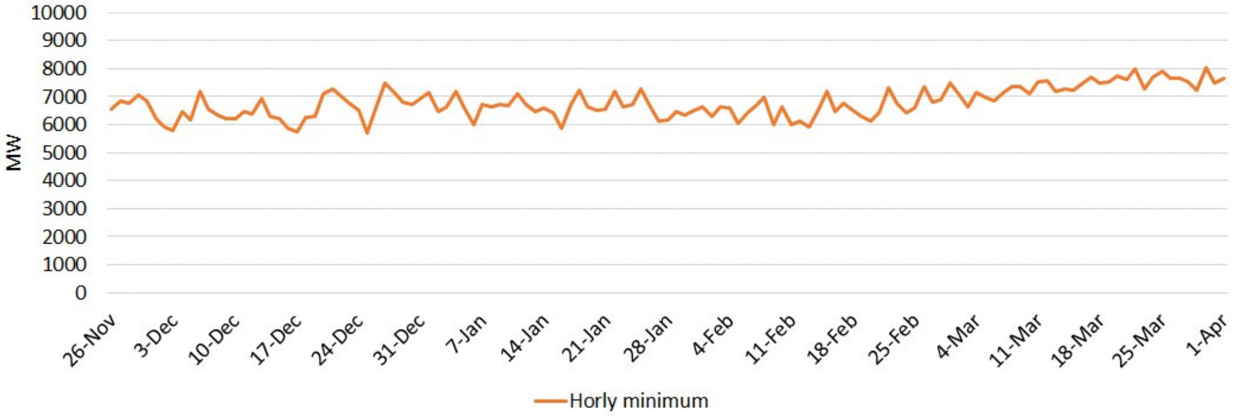


Figure 10: Minimum hourly TPP margin on each day of the analysed period

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

As an additional quality assurance, all provided data have been analysed 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 Med-TSO 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 (set of excel files) presents a database that will be regularly updated for each seasonal and mid-term adequacy assessment.

For the Winter Outlook 2022/23 data have been collected in August/September 2022. For some countries (like Tunisia for example), the demand forecast is changed and updated but to ensure the coherence of the demand forecast evolution with the mid-term adequacy (2025 and 2027), demand has not been updated.

This database will be updated in March 2023 with the latest information that will be used for the preparation of the next report - Summer Outlook 2023.

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 Med-TSO. These time series refer to different climatic conditions (mainly for the period 1981-2019 or similar, depending

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[3] https://www.med-tso.com/publications.aspx?f=&title=Reports

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.

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 Med-TSO 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 provided by Med-TSO. These time series are based on PECD, 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 Med-TSO 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,...) 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 (almost no hydro generation), balancing reserve has been modelled as demand increases in all countries having in mind that this approach is more strict 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 demand increase).

Considering the above-mentioned, the data provided by Med-TSO 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
- 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 Med-TSO.

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

2.4 Overview of the MED-TSO power systems in Winter 2022/23

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.

DEMAND EVOLUTION

Table 2 presents the expected consumption per week from the 48th week in 2022 to the 13th week in the year 2023. These values are the average weekly consumption for 38 climatic years in the period from 1982 to 2019.

Table 2: Expected consumption in the Winter weeks – 2022/23

Weekly consumption (GWh)		DZ	EG	JO	LB	LY	MA	TN
Total		**26138**	**69241**	**6937**	**7702**	**15778**	**14019**	**6562**
Week	48	1382	3727	365	404	789	766	351
Week	49	1396	3712	373	419	838	767	355
Week	50	1413	3717	383	431	878	766	359
Week	51	1416	3725	390	439	902	768	361
Week	52	1441	3734	392	440	933	769	368
Week	1	1483	3896	407	450	971	788	374
Week	2	1509	3910	418	464	965	776	372
Week	3	1515	3906	415	460	971	783	374
Week	4	1509	3878	411	455	957	783	374
Week	5	1505	3887	405	448	947	783	372
Week	6	1508	3884	398	427	955	784	374
Week	7	1497	3877	387	431	927	782	375
Week	8	1479	3867	381	424	885	780	367
Week	9	1449	3878	372	414	812	782	360
Week	10	1440	3894	363	403	812	784	360
Week	11	1409	3904	365	405	776	783	353
Week	12	1390	3914	360	397	742	788	355
Week	13	1397	3933	351	392	719	788	359

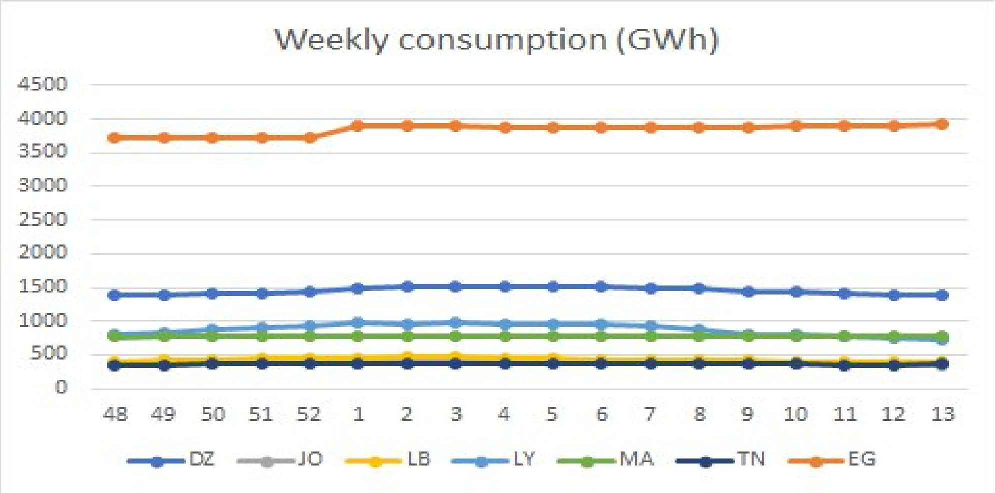
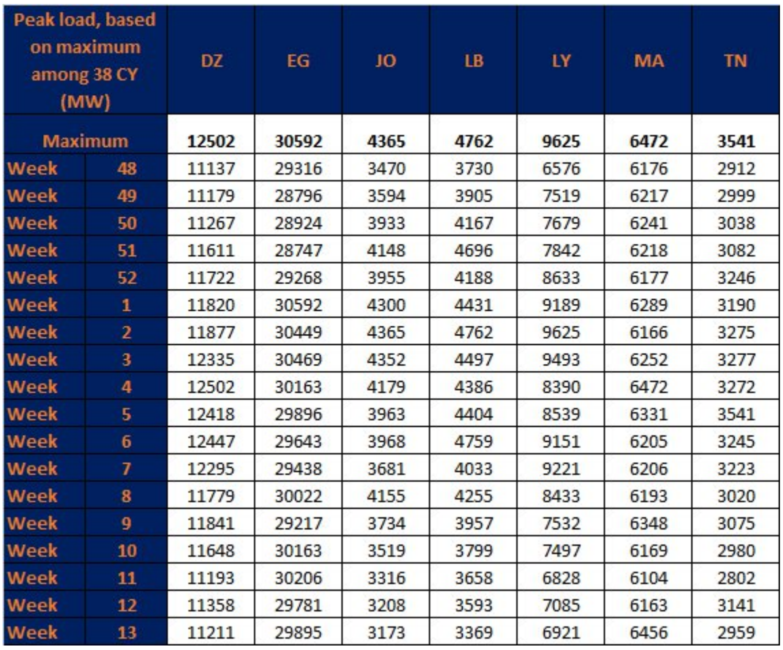


Figure 11: Expected weekly consumption per country in the analysed season

Weekly consumption in Jordan, Lebanon and Tunisia is the lowest among the analysed 7 countries. The highest is consumption in Egypt, almost 10 times higher. Consumption in Libya, Morocco and Algeria are in between, although still with high differences among them.

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

Table 3: Maximum weekly peak loads in winter weeks 2022/23



Peak load, based on maximum among 38 CY (MW)		DZ	EG	JO	LB	LY	MA	TN
Maximum		**12502**	**30592**	**4365**	**4762**	**9625**	**6472**	**3541**
Week	48	11137	29316	3470	3730	6576	6176	2912
Week	49	11179	28796	3594	3905	7519	6217	2999
Week	50	11267	28924	3933	4167	7679	6241	3038
Week	51	11611	28747	4148	4696	7842	6218	3082
Week	52	11722	29268	3955	4188	8633	6177	3246
Week	1	11820	30592	4300	4431	9189	6289	3190
Week	2	11877	30449	4365	4762	9625	6166	3275
Week	3	12335	30469	4352	4497	9493	6252	3277
Week	4	12502	30163	4179	4386	8390	6472	3272
Week	5	12418	29896	3963	4404	8539	6331	3541
Week	6	12447	29643	3968	4759	9151	6205	3245
Week	7	12295	29438	3681	4033	9221	6206	3223
Week	8	11779	30022	4155	4255	8433	6193	3020
Week	9	11841	29217	3734	3957	7532	6348	3075
Week	10	11648	30163	3519	3799	7497	6169	2980
Week	11	11193	30206	3316	3658	6828	6104	2802
Week	12	11358	29781	3208	3593	7085	6163	3141
Week	13	11211	29895	3173	3369	6921	6456	2959

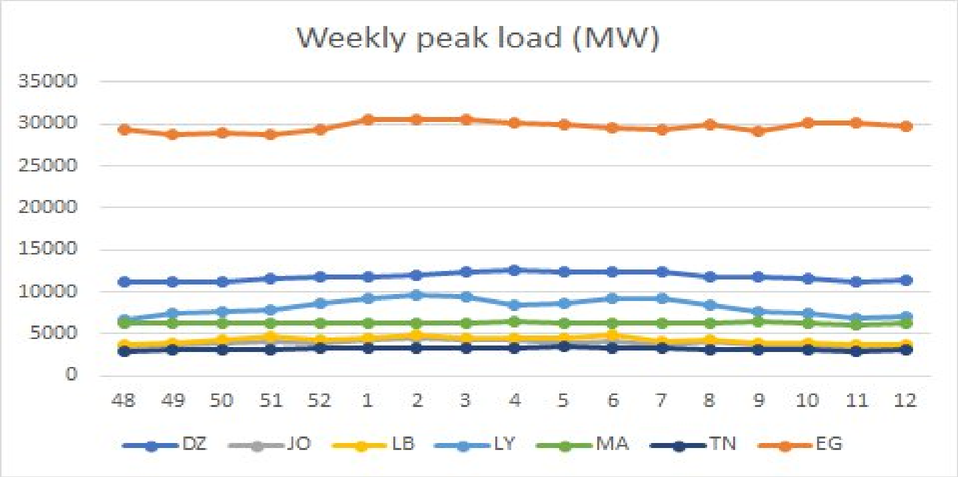


Figure 12: Maximum weekly peak loads per country in the analysed season

In all countries, except Jordan, peak load is observed in summer. In Jordan, the peak load is observed in winter and the value of 4365 MW presents the peak load for 2023.

It should be noted weekly consumption is rather constant during this period although there are more evident fluctuations of the peak load, especially in Libya (Figure 12).

Concerning, daily patterns, in each country there are seven rather similar daily profiles with one or two peaks within a day. In Algeria, daily profiles are almost the same and no day within a week is different. In the case of Egypt and Jordan, demand is slightly lower on Fridays while in Morocco and Tunisia on Sundays.

GENERATION CAPACITIES EVOLUTION

The following tables provide information about generation capacities in 2022 and 2023. Total generation capacities in the observed region are expected to reach 118 GW, with almost 104 GW (or around 88%) in thermal units.

Table 4: Total generation capacities (MW) per technology in 2022

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	1.15%	95	0.41%	22768	98.44%	**23129**
EG	1875	3.16%	1763	2.97%	2128	3.58%	53629	90.29%	**59395**
JO	621	9.49%	1705	26.05%	-	-	4220	64.47%	**6546**
LB	-	-	-	-	280	12.78%	1911	87.22%	**2191**
LY	-	-	-	-	-	-	7726	100.00%	**7726**
MA	1847	17.06%	827	7.64%	1306	12.06%	6849	63.25%	**10829**
TN	242	4.29%	215	3.81%	-	-	5183	91.90%	**5640**
TOTAL	**4585**	**3.97%**	**4776**	**4.14%**	**3809**	**3.30%**	**102286**	**88.59%**	**115456**

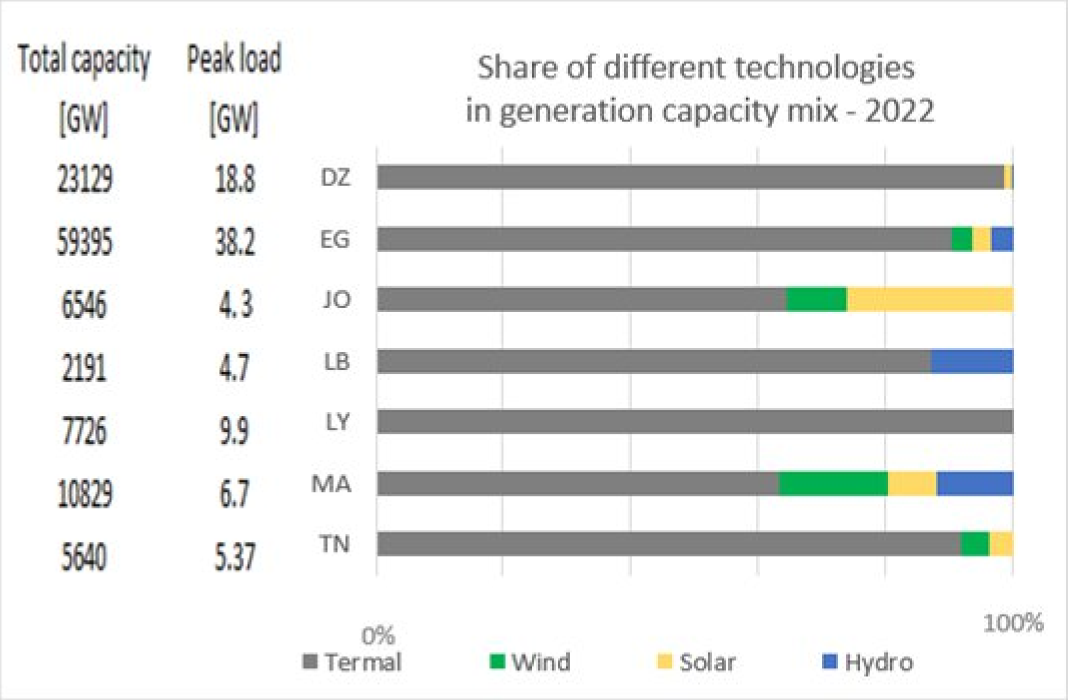


Figure 13: Generation capacity mix and peak load in 2022

Table 5: Total generation capacities (MW) per technology in 2023

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	1.12%	95	0.40%	23452	98.48%	**23813**
EG	1875	3.19%	1963	3.34%	2128	3.62%	52860	89.86%	**58826**
JO	621	9.36%	1795	27.05%	-	-	4220	63.59%	**6636**
LB	-	-	-	-	280	12.78%	1911	87.22%	**2191**
LY	-	-	-	-	-	-	8910	100.00%	**8910**
MA	2197	18.53%	1157	9.76%	1656	13.96%	6849	57.75%	**11859**
TN	242	4.19%	345	5.98%	-	-	5183	89.83%	**5770**
TOTAL	4935	4.18%	5526	4.68%	4159	3.52%	103385	87.61%	**118005**

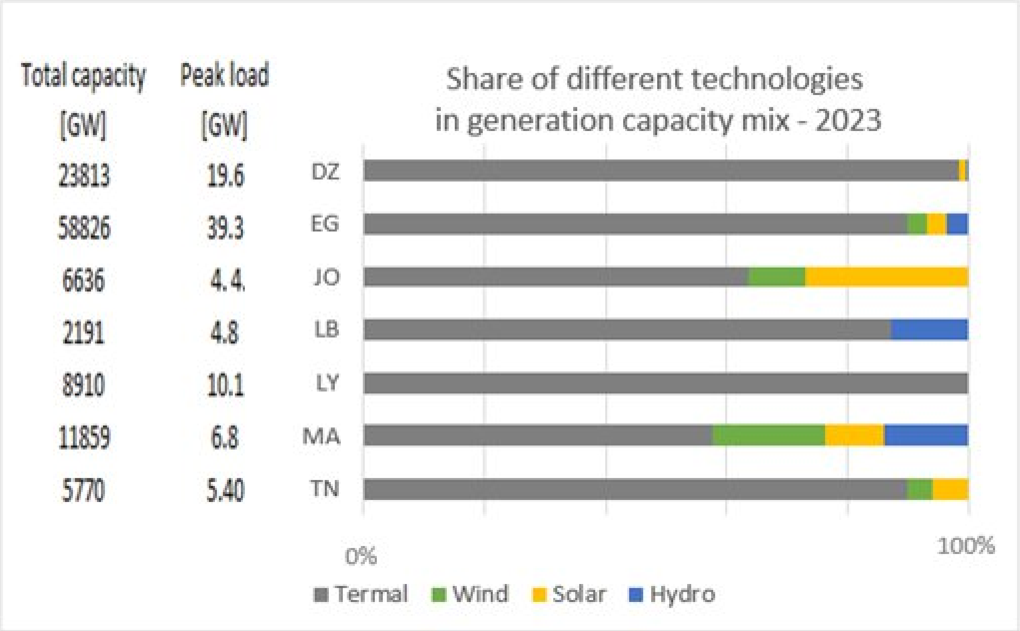


Figure 14: Generation capacity mix and peak load in 2023

It should be noted that the Libya's power system is characterized by thermal power plants only.

Relevant hydro capacities exist only in Egypt and Morocco. In Morocco, there is also a PS HPP with capacity of 464 MW in 2022 and 814 MW in 2023. The highest wind + solar capacities participation in total generation capacities is noted in Jordan and Morocco where their participation reaches more than 35%. It should be noted that in Morocco, 530 MW of solar capacity is in solar thermal farms with storage.

Capacity factors related to wind and solar generation are presented in Table 6. It is worth mentioning that capacity factors take into account the technology used and also the zone splitting of each country.

Table 6: Wind and solar capacity factors for all countries in 2022/23

	2022/23	
Country	**Wind CF**	**Solar CF**
DZ	N/A	21.2%
EG	39.3%	26.3%
JO	32.5%	22.8%
LB	-	-
LY	-	-
MA	46.5%	33.5%
TN	30%	19.5%/20.2%

The impact of RES generation in Algeria, Egypt and Tunisia is marginal since the participation of thermal units is above 90%. 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 (DZ, JO, TN) or as random outages enabled during the whole analysed period December-March.

It should be emphasized that in case of winter outlook adequacy analysis, months of two different calendar years are used within simulations. Therefore, all input data such as load time-series or wind and solar installed capacities and capacity factors refer to two different years. In other words, for winter months November-December, input data given for 2022 were used while for period January-April input data for 2023 were used. As a consequence of such an approach, large discontinuity in time series may appear on 1st January, depending on the country and changes in forecasted/planned values.

Similar, for thermal units, commissioning/decommissioning dates are taken into account. In practice there are cases when a group of thermal units enter into operation at the same date, usually on 1st January, which may cause large discontinuity in installed capacities at the middle of the analyzed period.

In order to overcame these effects, it is recommended that commissioning/decommissioning dates should be given more precisely.

INTERCONNECTIONS BETWEEN COUNTRIES

Summarized NTC values provided by Med-TSO are used as available cross-border capacities and we assumed that these capacities are fully available for commercial exchanges for the entire calculation period.

The Antares model included the power systems of 7 analysed 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 Med-TSO. A summary of the interconnection capacities and given exchanges is presented in the following tables.

Table 6: Summarized NTC values

Interconnection NTC [MW]	2022 and 2023
DZ-TN	600
TN-DZ	600
DZ-MA	600
MA-DZ	300
EG-LY	180
TN-LY	250
EG-JO	450
JO-EG	450
MA-ES	600
ES-MA	900
JO-LB	250
LB-JO	0

Table 7: Max hourly exchanges

Interconnection Max hourly exchanges [MW]	2022 AND 2023
EG-SD	80
SD-EG	0
JO-PS	80
PS-JO	0
IQ-JO	0
JO-IQ	150-200

RESERVE REQUIREMENTS AND THEIR MODELLING

Reserve requirements have been provided by Med-TSO (Table 7). In some countries (EG, 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 demand increase.

FRR requirements have been modelled as demand increase in all countries.

Table 7: Balancing reserve requirements

Reserve		2022 and 2023
DZ	FCR+FRR [MW]	400
EG	FCR+FRR [MW][4]	600
JO	FCR+FRR [MW]	360
MA	FCR+FRR [MW]	600
TN	FCR+FRR [MW]	450

In the case of Lebanon and Libya reserve requirements have not been considered or modelled.

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[4] FCR for EG & MA has been modeled through reduced thermal capacity.

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)[5] 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 (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.

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[5] Planned outages have not been considered during December and January in case of Jordan. In all other countries no specific constraints have been applied.

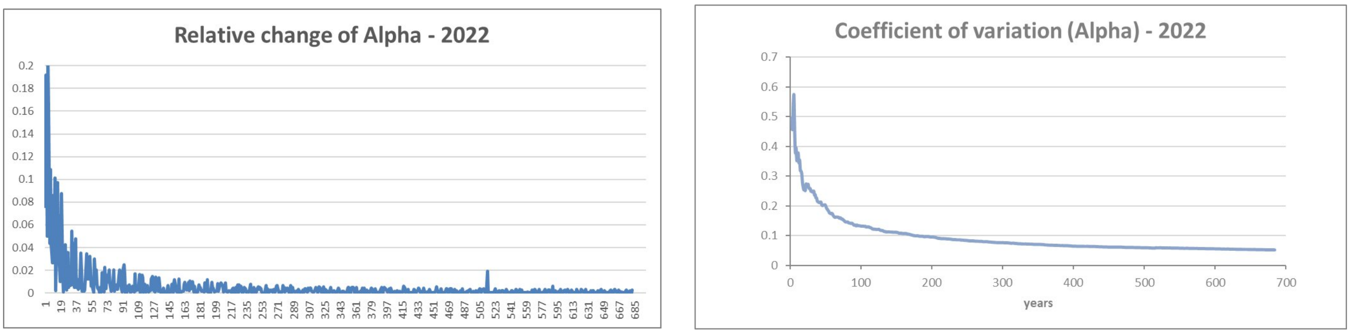

Figure 15: Evolution of convergence criteria for 684 MC years, simulations for the year 2022

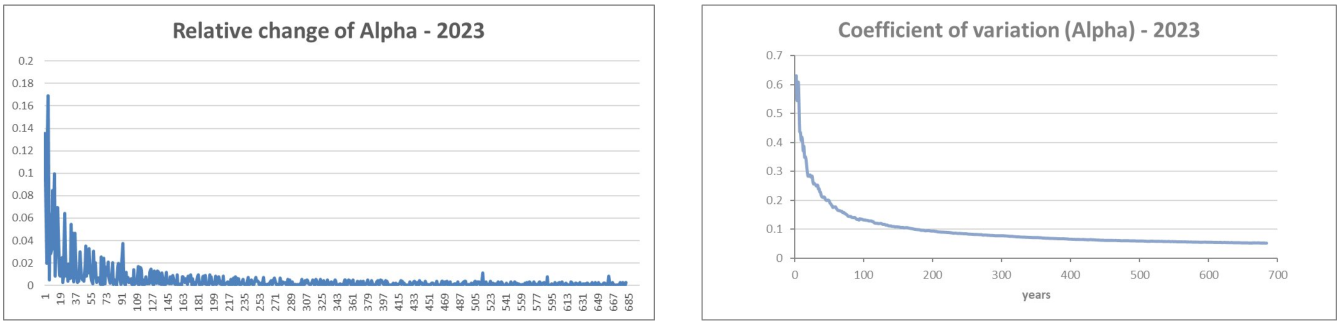

Figure 16: Evolution of convergence criteria for 684 MC years, simulations for the year 2023

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 Med-TSO interconnections.

In the case of a theoretical isolated scenario, adequacy risks are observed in all countries except Algeria and Egypt, although they could be considered small or marginal in Morocco, Jordan and Tunisia (Figure 16). Only in the case of Lebanon and Libya adequacy risk is very high under isolated system operating mode. Interconnections and energy exchanges with neighbouring countries reduce adequacy risks to zero in the case of Morocco and Tunisia, and almost to zero in Jordan, but, in Lebanon and Libya even in this more relaxed operating mode, adequacy risks are at an unacceptable level (Figure 17)[6].

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[6] Colour coding of adequacy risk levels presented in Figure 17 and Figure 18 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

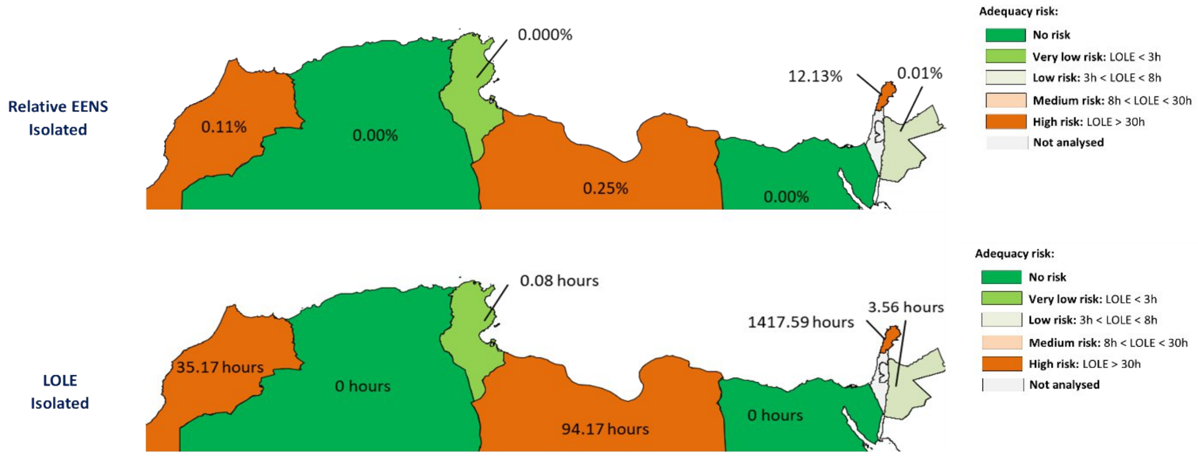


Figure 17: Seasonal Relative EENS and LOLE for the isolated mode of operation

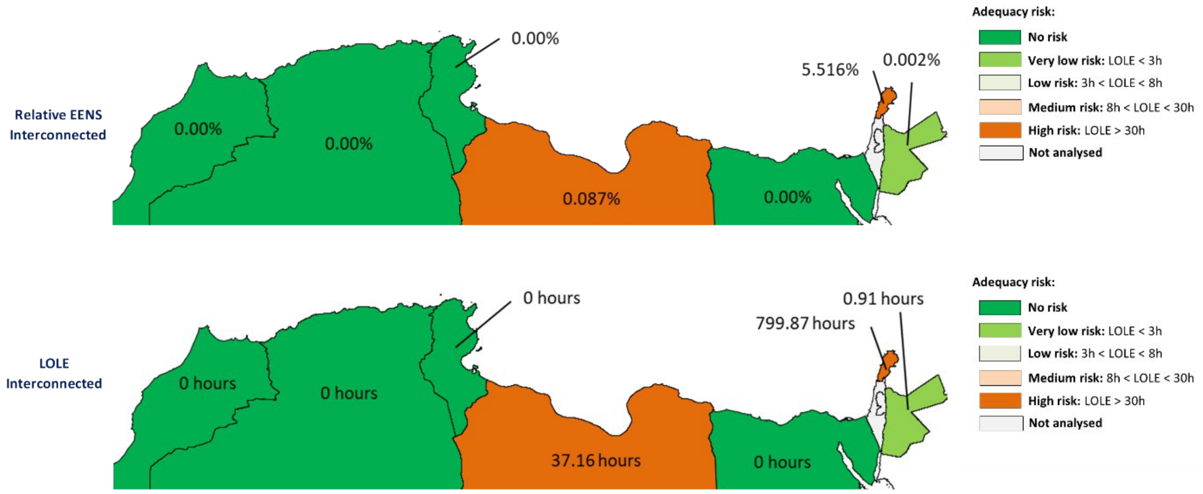


Figure 18: Seasonal relative ENS and LOLE for the interconnected mode of operation

In Table 8 detailed ENS and LOLD seasonal results are given for all analysed countries. Results point to adequacy issues in some countries. Notably in:

- Jordan

  Jordan with EENS of only 166 MWh for the interconnected mode of operation and LOLE of less than one hour, shows a small adequacy risk. However, in a rare situation, but more critical one (P95), ENS can reach 53 MWh and LOLD of 1 hour. Adequacy risks increase in isolated operating mode, but it is still within the acceptable range.

- Libya

  This is the country with high EENS and LOLE observed in Winter 2022/23: 15 GWh and 37 hours in the interconnected mode of operation. These expected values of ENS and LOLE point to seriously endangered adequacy. If more critical, but less probable (P95) cases happen (higher demand, frequent outages of TPPs) ENS can reach 52 GWh during 113 hours.

  In the isolated mode of operation, adequacy is even more endangered: EENS reaches 41 GWh and LOLE is 91 hours. This also points to the fact that interconnections with Egypt and Tunisia reduce adequacy risks 2 times!
- Lebanon

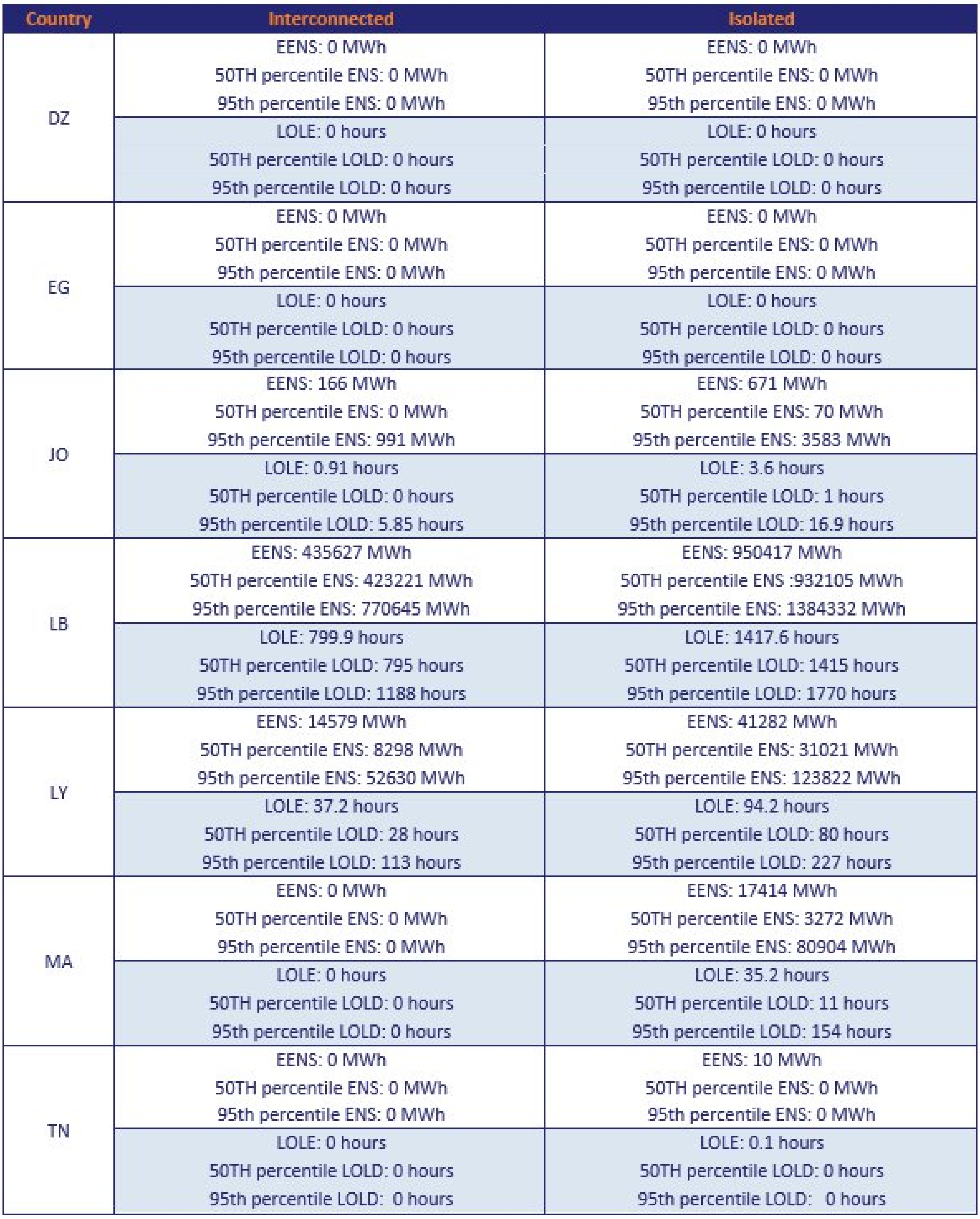
  This is the country with the highest EENS and LOLE observed in Winter 2022/23 in this region:435 GWh of ENS and 800 hours of LOLE (20% of the time!) in the interconnected mode of operation. These expected values of ENS and LOLE point to extremely endangered adequacy. If more critical, but less probable (P95) cases happen ENS can reach 770 GWh with unavailability to supply the load during more than 30% of the period.

  In the isolated mode of operation, adequacy is even more endangered: EENS reaches 950 GWh and LOLE is 1418 hours. This also points to the fact that interconnection with Jordan reduces adequacy risks 2 times!

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.

Table 8: Seasonal ENS for Interconnected and isolated scenario



Country	Interconnected	Isolated
DZ	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours
EG	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours
JO	EENS: 166 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 991 MWh	EENS: 671 MWh 50TH percentile ENS: 70 MWh 95th percentile ENS: 3583 MWh
	LOLE: 0.91 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 5.85 hours	LOLE: 3.6 hours 50TH percentile LOLD: 1 hours 95th percentile LOLD: 16.9 hours
LB	EENS: 435627 MWh 50TH percentile ENS: 423221 MWh 95th percentile ENS: 770645 MWh	EENS: 950417 MWh 50TH percentile ENS :932105 MWh 95th percentile ENS: 1384332 MWh
	LOLE: 799.9 hours 50TH percentile LOLD: 795 hours 95th percentile LOLD: 1188 hours	LOLE: 1417.6 hours 50TH percentile LOLD: 1415 hours 95th percentile LOLD: 1770 hours
LY	EENS: 14579 MWh 50TH percentile ENS: 8298 MWh 95th percentile ENS: 52630 MWh	EENS: 41282 MWh 50TH percentile ENS: 31021 MWh 95th percentile ENS: 123822 MWh
	LOLE: 37.2 hours 50TH percentile LOLD: 28 hours 95th percentile LOLD: 113 hours	LOLE: 94.2 hours 50TH percentile LOLD: 80 hours 95th percentile LOLD: 227 hours
MA	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 17414 MWh 50TH percentile ENS: 3272 MWh 95th percentile ENS: 80904 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 35.2 hours 50TH percentile LOLD: 11 hours 95th percentile LOLD: 154 hours
TN	EENS: 0 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 10 MWh 50TH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
	LOLE: 0 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours	LOLE: 0.1 hours 50TH percentile LOLD: 0 hours 95th percentile LOLD: 0 hours

3.3 Importance of interconnections[7]

As presented in the previous chapter, present the crucial support for adequacy in almost all countries except Algeria and Egypt, which have a surplus of generation capacity. Exchanges on the borders of the seven analysed countries show that in almost all cases there is the prevailing direction of the power flows (Figure 19):

- From DZ to MA
- From DZ to TN
- From MA to ES (from North Africa to Europe)
- From EG to JO
- From JO to LB
- From EG and TN to LY

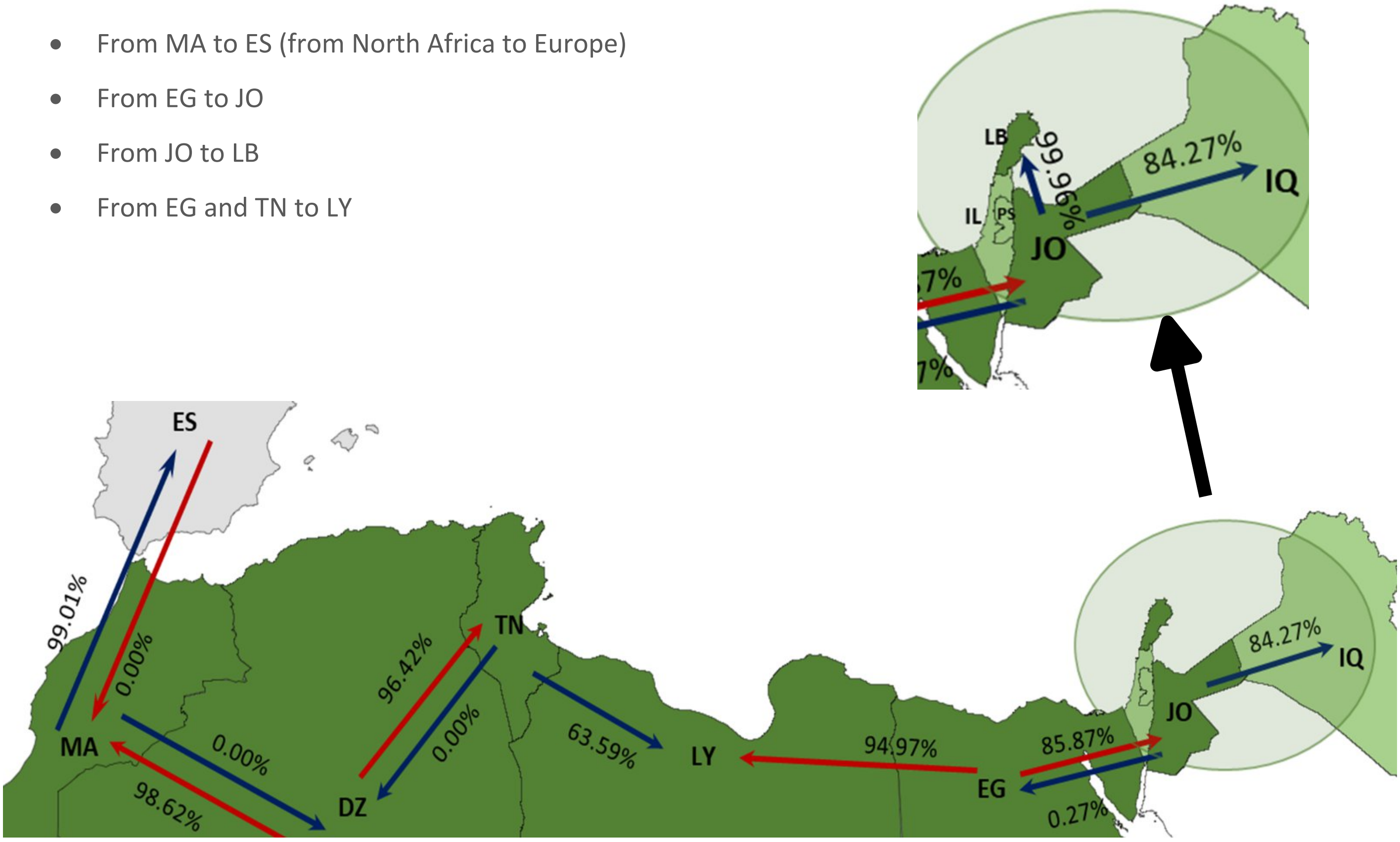


Figure 19: Exchange direction and transfer capacity utilization during 18 weeks of the 2022/23 winter season (average of all MC years)

Note: Diagram presents potential commercial exchanges that include exchanges that support adequacy

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[7] **Please have in mind that exchanges are not completely in line with market operation since loads are increased for required reserve**

Table 9: Seasonal exchanges and utilization of the links in the region

Link	Possible Annual Exchanges (GWh)	NTC direct (MW)	NTC indirect (MW)	Utilization factor (%)
DZ00 - MA00	1,789,368	600	300	98.62%
DZ00 - TN00	1,749,482	600	600	96.42%
EG00 - JO00	1,172,191	450	450	86.14%
EG00 - LY00	516,922	180	0	94.97%
EG00 - SD00	241,840	240	0	33.32%
ES00 - MA00	1,796,402	900	600	99.01%
IQ00 - JO00	509,641	0	200	84.27%
JO00 - PS00	241,626	80	0	99.88%
JO00 - LB00	755,695	250	0	99.96%
LY01 - TN	480,762	0	250	63.59%

Presented exchanges point to the fact that Algeria has sufficient excess of energy to support the secure operation of Tunisia and that this support is just limited by the transmission constraints (NTC=600 MW). Increased transmission capacity from 400 MW to 600 MW obviously improves the adequacy situation in Tunisia. Excess of generation in Algeria is also used for export to Spain via Morocco. Part of the export to Spain comes also from Morocco.

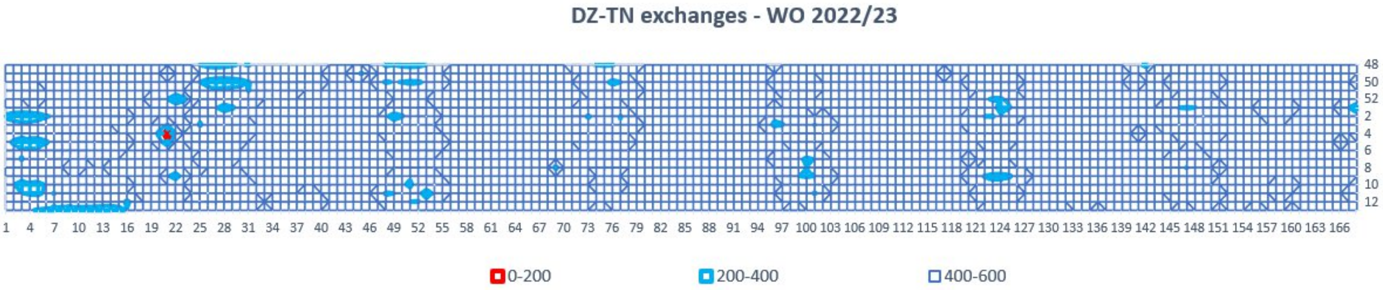
Export from Egypt to Jordan also improves the adequacy situation in Jordan, although even without this support, adequacy risks in Jordan are within acceptable limits. In addition to Jordan, Egypt is exporting around 240 GWh to cope with the need of Sudan.

The situation in Lebanon and Libya is completely different and interconnections and imported energy are of large importance to these countries. Interconnection enables a reduction in adequacy issues by 2-3 times in these two countries.

The following heat maps present the hourly flows (168 hours in each week during the winter season) on the selected borders for the selected MC year (first MC year):

- DZ - TN

Flows in all hours are towards Tunisia, between 46 MW and 600 MW (which is the NTC value).

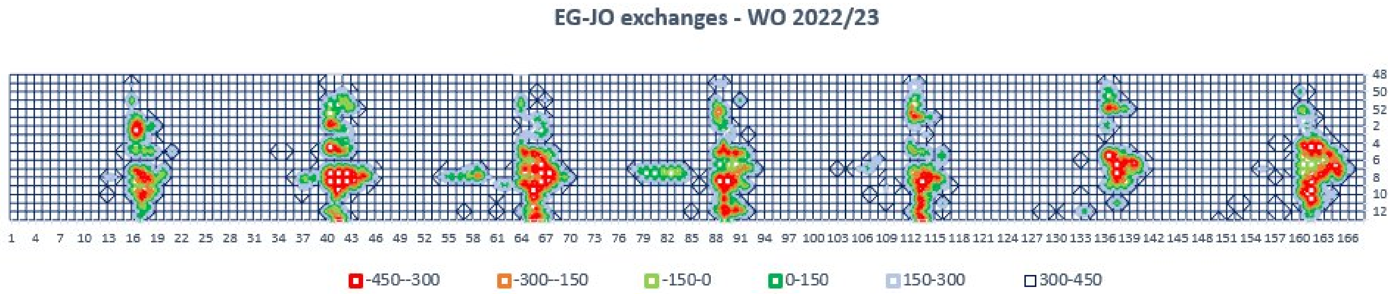


- DZ - MA

Prevailing flows are from Algeria to Morocco mainly due to high export to Spain. Flows from Morocco to Algeria are noted only during the night and early morning hours when demand is still low and Morocco has an excess in RES generation.

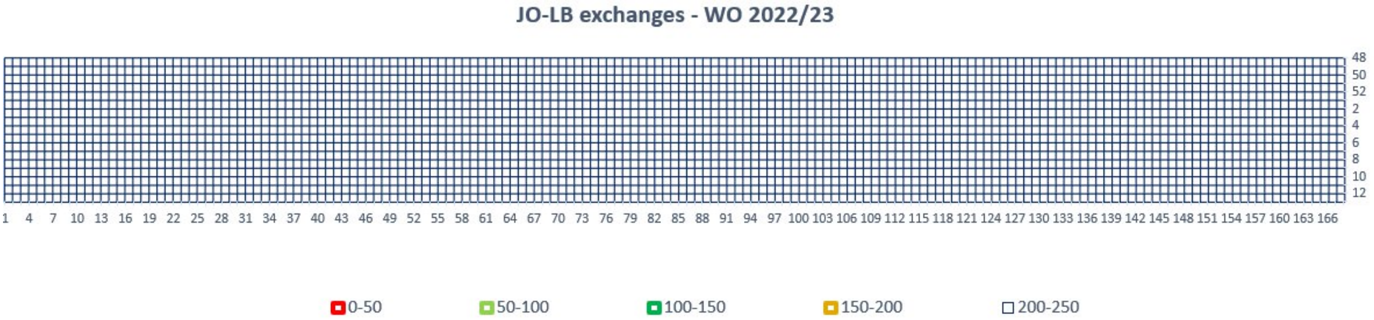
- EG - JO

Prevailing flows are from Egypt to Jordan, with reduction and even counterflow during afternoon and evening hours when the load in Jordan is lower.



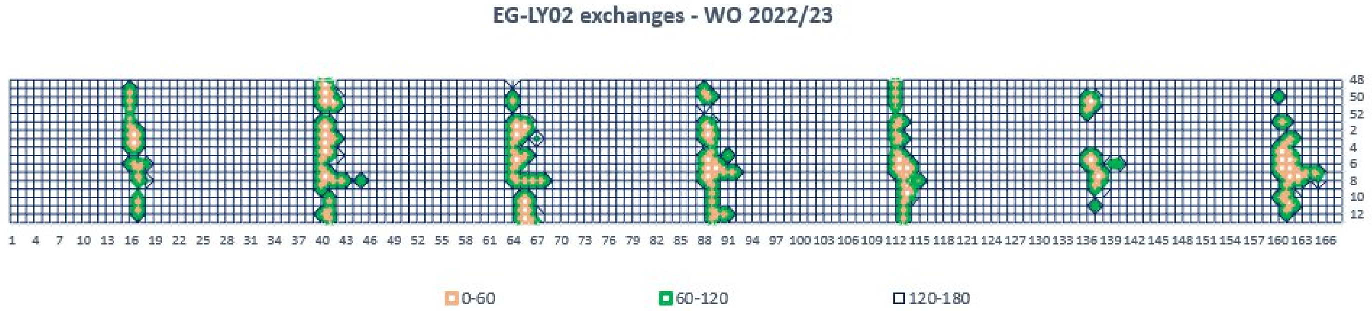
- JO - LB

  During all hours, full NTC capacity is utilised for export from Jordan to Lebanon. It should be noted that part of this energy comes from Egypt.



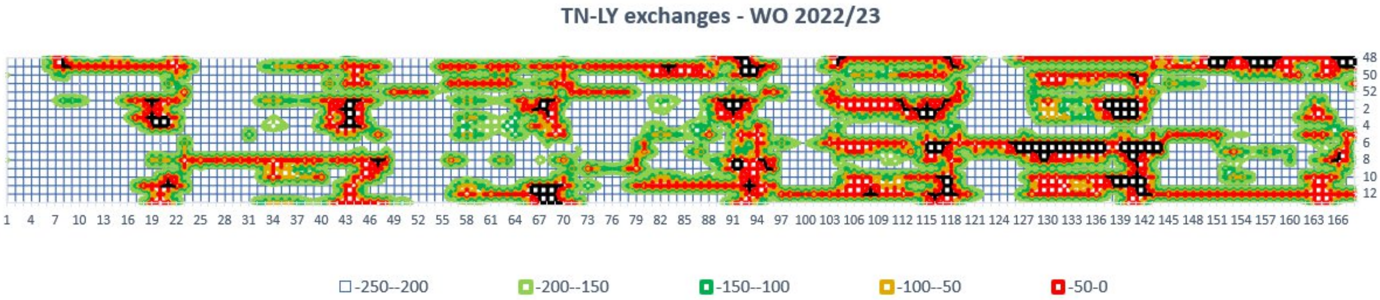
- EG - LY

  There are only flows towards Libya. Mainly flow is at its maximum (180 MW) with a reduction during afternoon hours when the load in Libya is lower.



- TN - LY

  There are flows only towards Libya. However, interconnection capacity is not utilized by 100% since excess of generation is not present in Tunisia at all hours. During hours with higher demand in Tunisia, export to Libya is reduced.



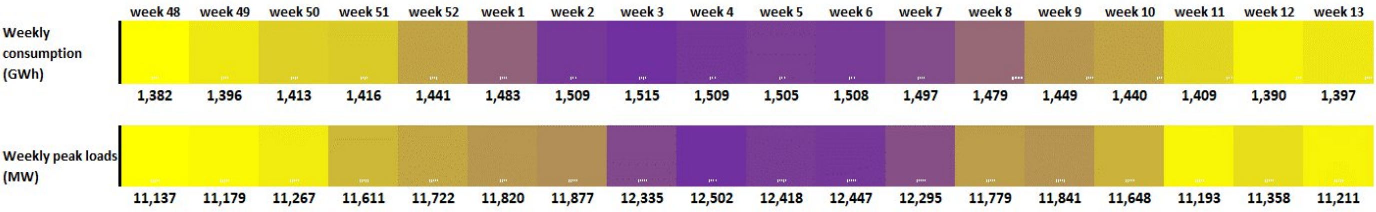
4 Adequacy Situation on Country Level

4.1 Algeria

DEMAND

Algerian seasonal weekly demand, depicted in Figure 20 goes from around 1400 GWh to 1500 GWh, while peak hourly demand in each week varies from 11000 MW to 12500 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected during the first couple of weeks in 2023 (in January), due to low temperatures and some heating demand. The maximum hourly demand in all 38 climatic years reaches 12502 MW in the 4th week of 2023.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	1,382	1,396	1,413	1,416	1,441	1,483	1,509	1,515	1,509	1,505	1,508	1,497	1,479	1,449	1,440	1,409	1,390	1,397
Weekly peak loads (MW)	11,137	11,179	11,267	11,611	11,722	11,820	11,877	12,335	12,502	12,418	12,447	12,295	11,779	11,841	11,648	11,193	11,358	11,211

Figure 20: Seasonal Weekly demand in Algeria

SUPPLY AND NETWORK OVERVIEW

Algerian power generation fleet is almost exclusively based on natural gas, with the gas TPP share in total installed capacities around 98%, which is divided further into conventional, CCGT and OOCGT TPPs. Hydro and Solar capacities amount to only 1% each. Total installed capacities are 23813 MW with import capacity up to 900 MW, which combined is substantially higher than the maximum peak demand of 12502 MW.

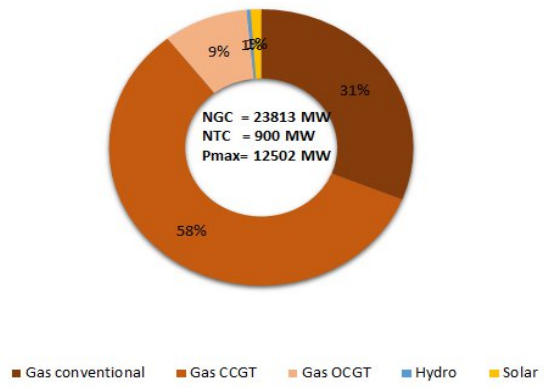


Figure 21: Installed Capacity mix with total NGC, import NTC and peak demand in Algeria

The average daily available TPP capacity, after reduction due to forced and planned outages, is shown in Figure 22. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation.

Algerian average available TPP capacities level is almost constant during the winter season, at the level of 20 GW. The minimal average daily available TPP capacity (minimum among all simulated MC years) has small fluctuations around 19 GW.

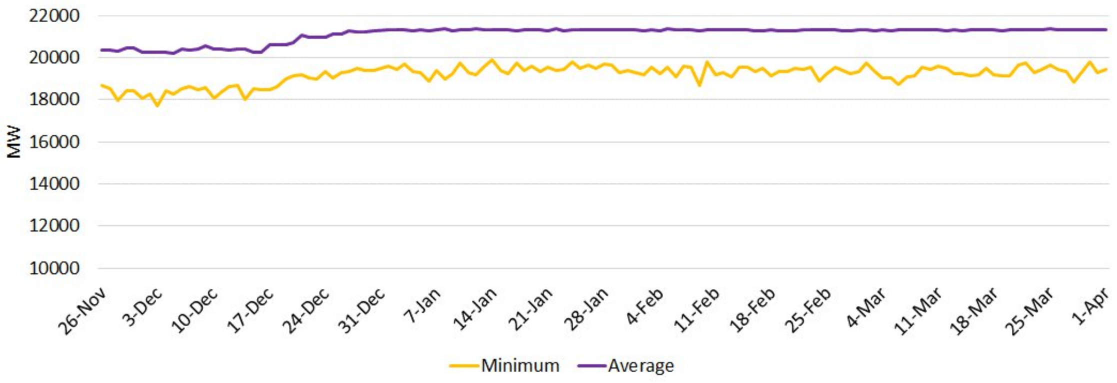


Figure 22: Average and minimum TPP available capacity in Algeria

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 23. It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 6 GW and 8 GW during the analysed winter season. The high Algerian TPP capacity margin indicates that Algeria doesn't have adequacy issues and has significant export capabilities that can provide support to neighbouring power systems. Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during the first couple of weeks in 2023 when demand is the highest.

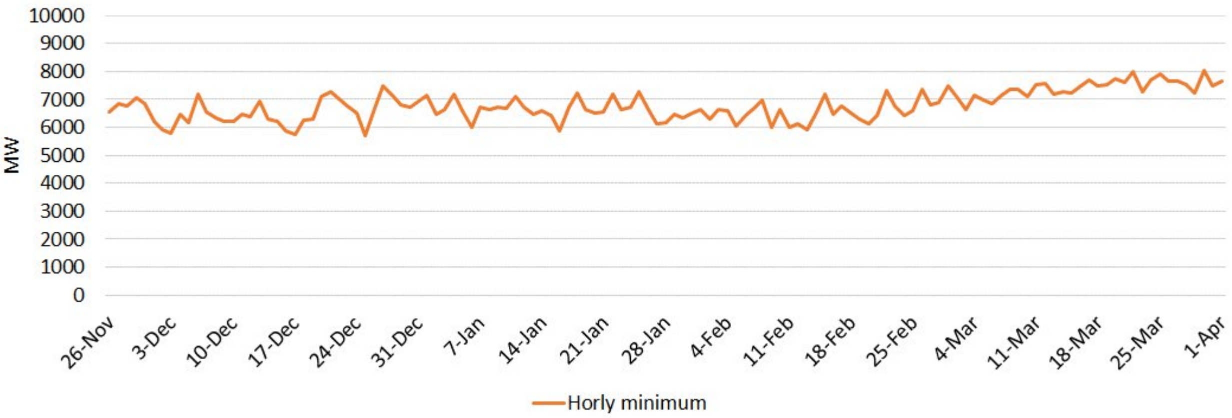


Figure 23: Minimum hourly TPP margin on each day of the analysed period in Algeria

ADEQUACY ASSESSMENT

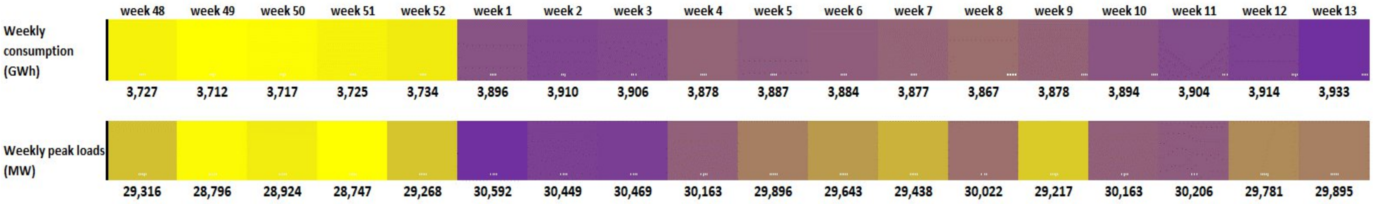
Considering that Algeria does not have any adequacy risk in the next winter season, further investigations are not relevant.

4.2 Egypt

DEMAND

Egyptian seasonal weekly demand, depicted in Figure 24 goes from around 3700 GWh to 3930 GWh, while peak hourly demand in each week varies from 28.7 GW to 30.5 GW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

As can be seen from the figure below, consumption is rather constant during the first 3 months of 2023 and higher than consumption at the end of 2022. 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 2023.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	3,727	3,712	3,717	3,725	3,734	3,896	3,910	3,906	3,878	3,887	3,884	3,877	3,867	3,878	3,894	3,904	3,914	3,933
Weekly peak loads (MW)	29,316	28,796	28,924	28,747	29,268	30,592	30,449	30,469	30,163	29,896	29,643	29,438	30,022	29,217	30,163	30,206	29,781	29,895

Figure 24: 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 90%, which is divided further into conventional and CCGT TPPs. Oil TPPs share is 2%, while Hydro share is 4%. RES – wind and solar capacities amount only to 3% each. Total installed capacities are 588 265 MW with import capacity up to 450 MW from Jordan, which combined is substantially higher than the maximum hourly consumption of 30 592 MW. In sense of demand and installed capacities, Egypt is the biggest of all analysed power systems.

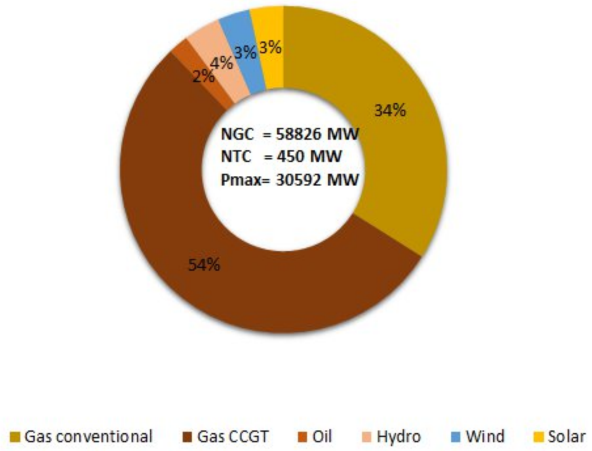


Figure 25: Installed Capacity mix with total NGC, import NTC and peak demand in Egypt

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 26. 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, but also due to reduced capacity of TPPs during February (derating factor of 10%). The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates from 32 GW to 39 GW.

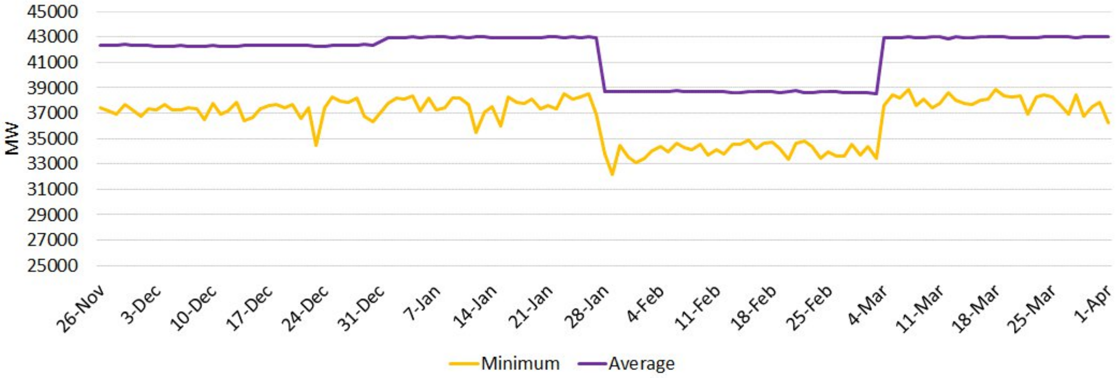


Figure 26: Average and minimum TPP available capacity in Egypt

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 27. It represents the difference between available and activated TPP capacities. The minimum hourly value of the capacity margin is the lowest during February (due to the additionally reduced efficiency of TPPs) and reaches a minimum of 5200 MW. The maximum in the winter period is around 13700 MW.

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 neighbouring countries' adequacy situation. Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during working days, due to higher demand.

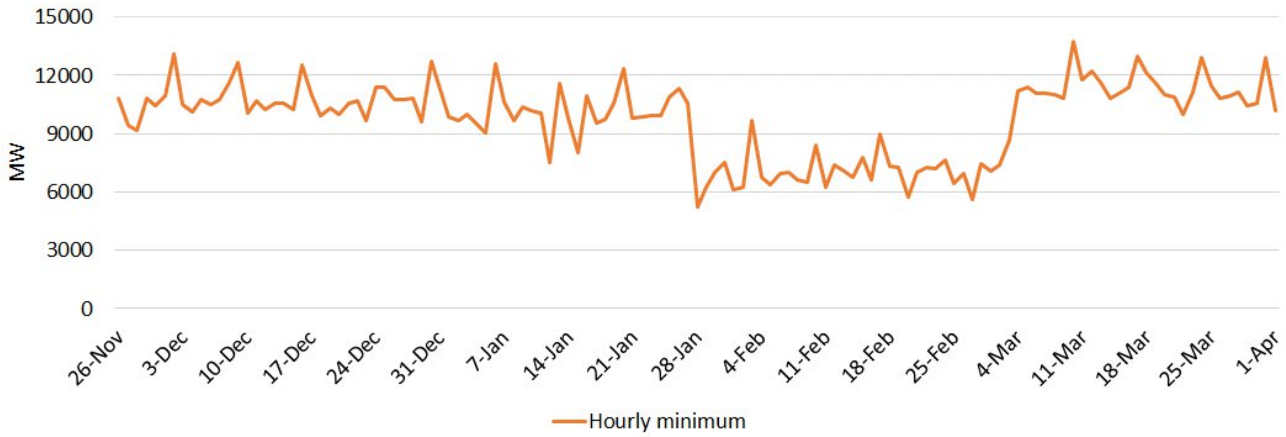


Figure 27: Minimum hourly TPP margin on each day of the analysed period in Egypt

ADEQUACY ASSESSMENT

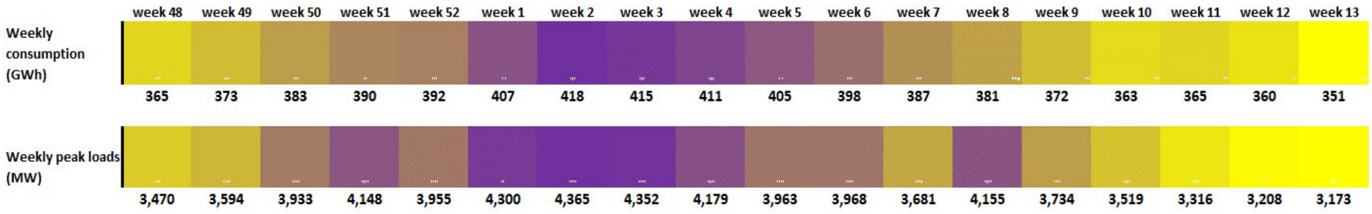
No adequacy concerns are detected for both analysed modes of operation in the case of Egypt.

4.3 Jordan

DEMAND

Jordan's seasonal weekly demand, depicted in Figure 28, goes from around 350 GWh to 420 GWh (fluctuation at the level of 20%), while peak hourly demand in each week goes from 3200 MW to 4360 MW which presents even higher fluctuation – 36%. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in the first weeks of 2023, due to low temperatures and heating demand. The maximum hourly demand of 4365 MW is reached in the 2nd week of 2023.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	365	373	383	390	392	407	418	415	411	405	398	387	381	372	363	365	360	351
Weekly peak loads (MW)	3,470	3,594	3,933	4,148	3,955	4,300	4,365	4,352	4,179	3,963	3,968	3,681	4,155	3,734	3,519	3,316	3,208	3,173

Figure 28: Seasonal Weekly demand in Jordan

SUPPLY AND NETWORK OVERVIEW

Jordan's power generation fleet is dominantly based on gas-fuelled TPPs, with the share in total installed capacities around 63%, 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 9% and 27% respectively. Total installed capacities amount to 6636 MW with an import capacity up to 450 MW from Egypt.

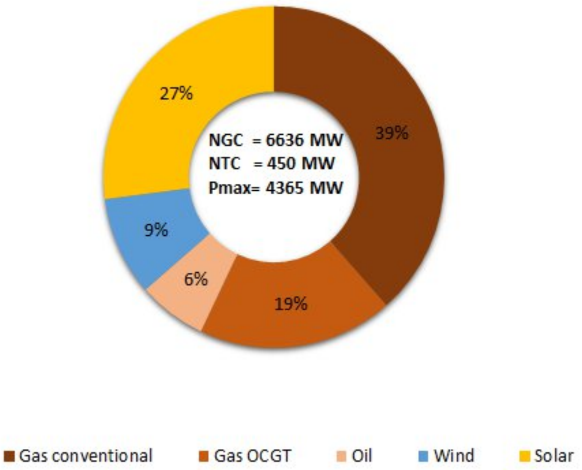


Figure 29: Installed Capacity mix with total NGC, import NTC and peak demand in Jordan

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages is shown in Figure 30. 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 start from 3500 MW and increase to 4100 MW from the first days of 2023. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 2500 MW to only 3100 MW.

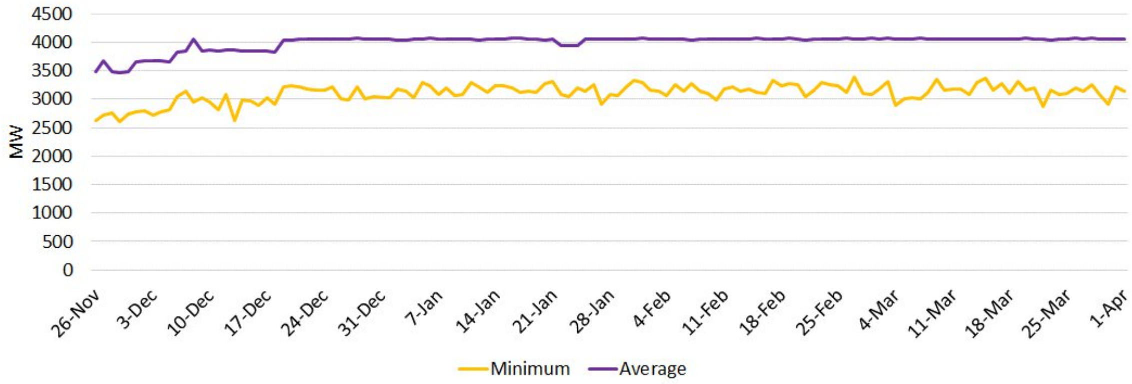


Figure 30: Average and minimum TPP available capacity in Jordan

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 31. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin each day is at zero value during the last days of 2022 and the beginning of 2023. From March, this margin is a little bit higher due to a decrease in demand. Still, the TPP margin is at a low level, below 300 MW. 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.

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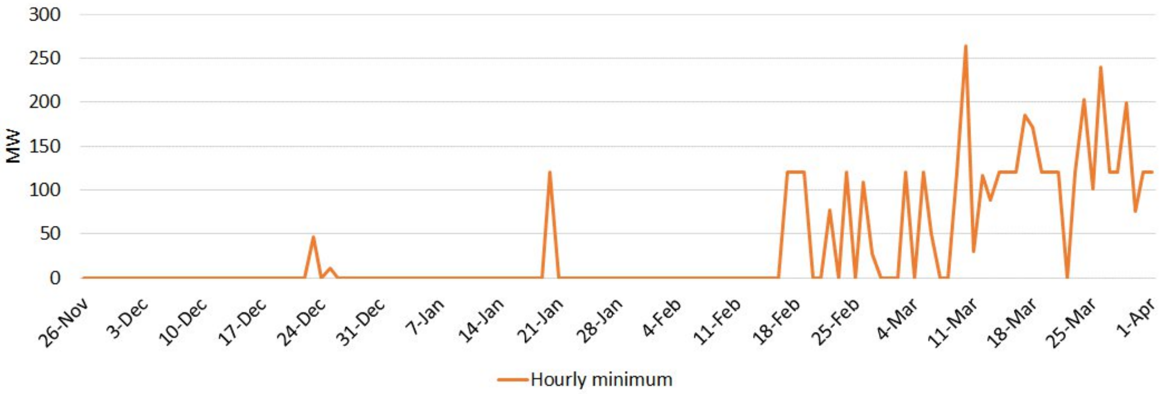


Figure 31: Minimum hourly TPP margin on each day of the analysed period in Jordan

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 32, 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, especially during the end of 2022 and the first month of 2023 because of high demand. Maximum hourly shortage in supply during the winter season in the interconnected mode of operation and within all 684 MC years is high - 1195 MW (This happens in week 2 in only one MC year, in the hour with high demand and big units in either planned or forced outage).

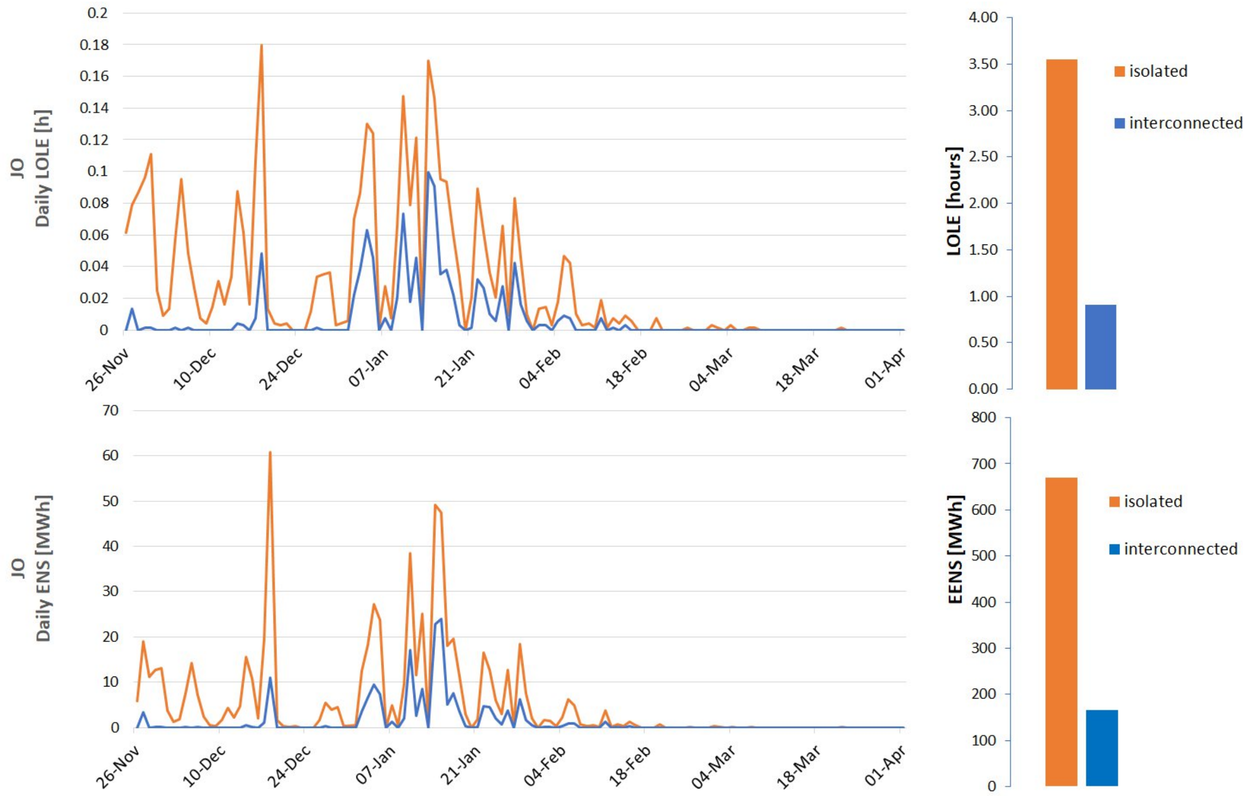


Figure 32: Daily LOLE and EENS for the interconnected and isolated mode of operation

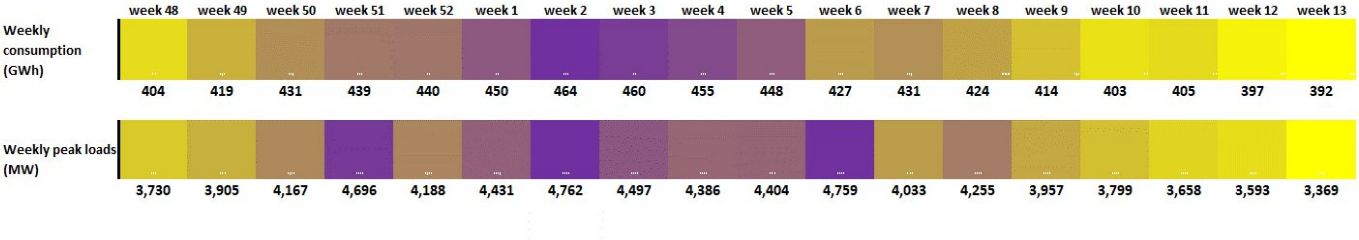
At the righthand part of the figure, LOLE and EENS for the entire season for both modes of system operation are given. Interconnections substantially reduce already small seasonal LOLE from 3.6 h to less than 1 h and expected seasonal EENS from 671 MWh to 166 MWh.

4.4 Lebanon

DEMAND

Lebanon's seasonal weekly demand, depicted in Figure 33, goes from around 400 GWh to 460 GWh, while peak hourly demand each week goes from 3400 MW to 4700 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected during the first weeks of 2023, due to low temperatures and increased heating demand. The maximum hourly demand of 4762 MW is reached in the 2nd week of 2023.
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.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	404	419	431	439	440	450	464	460	455	448	427	431	424	414	403	405	397	392
Weekly peak loads (MW)	3,730	3,905	4,167	4,696	4,188	4,431	4,762	4,497	4,386	4,404	4,759	4,033	4,255	3,957	3,799	3,658	3,593	3,369

Figure 33: Seasonal Weekly demand in Lebanon

SUPPLY AND NETWORK OVERVIEW

Lebanon's power generation fleet is exclusively oil-fuelled, with the share in total installed capacities around 87%. The rest of the 13% goes to hydro power plants. No wind or solar capacities are yet installed. Total installed capacities amount to 2191 MW, but as serious support to system operation, also the additional capacity of 1000 MW in diesel units is considered in this analysis.

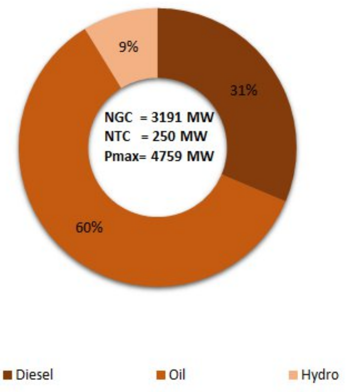


Figure 34: Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon

The average daily available TPP capacity, after reduction due to forced and planned outages, is shown in Figure 35. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated 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 is around only 2500 MW, but the minimum average daily available TPP capacity (minimum among all simulated MC years) goes down to even only 1400 MW.

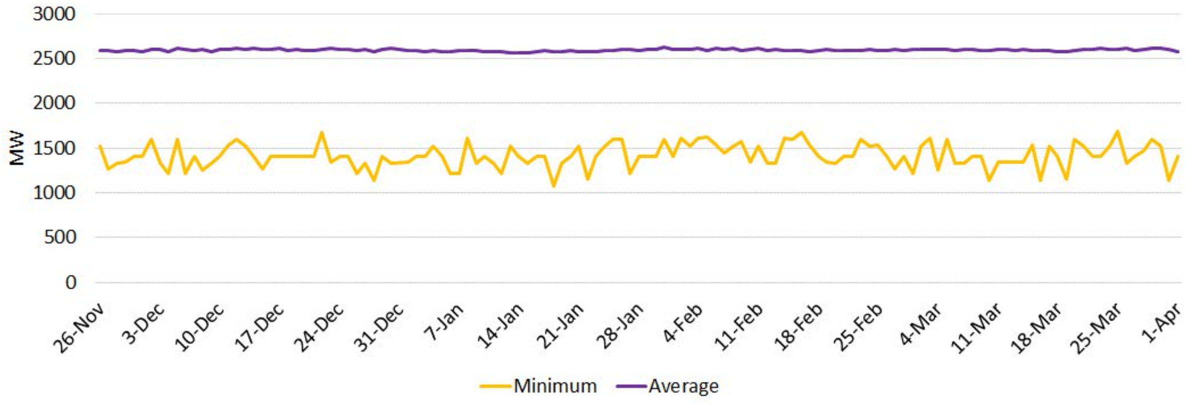


Figure 35: Average and minimum TPP available capacity in Lebanon

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 36. It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.

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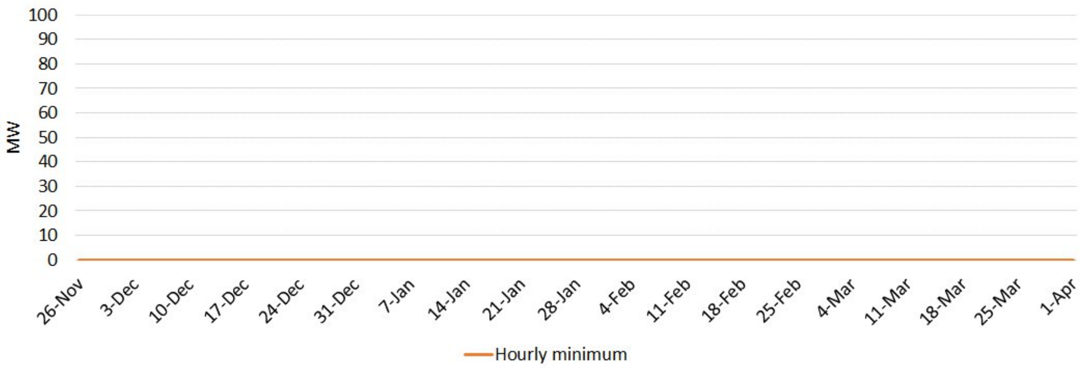


Figure 36: Minimum hourly TPP margin on each day of the analysed period in Lebanon

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 37 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 the operation of this power system is non comparable with any other in this region. The level 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 points to the fact that LOLE and ENS are above all acceptable values even in the interconnected mode of operation: ENS is 43 GWh and LOLE is 800 hours (during the winter season of 3024 hours). There are days 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, there are days with adequacy issues: LOLD min=173 hours and LOLD max=1548hours.

Maximum hourly shortage in supply during the winter season in the interconnected mode of operation and within all 684 MC years is enormous - 3819 MW (This happens in only one MC year in the hour with high demand and big units in either planned or forced outage).

The peak of adequacy issues is expected between the middle of December 2022 and the end of January 2023.

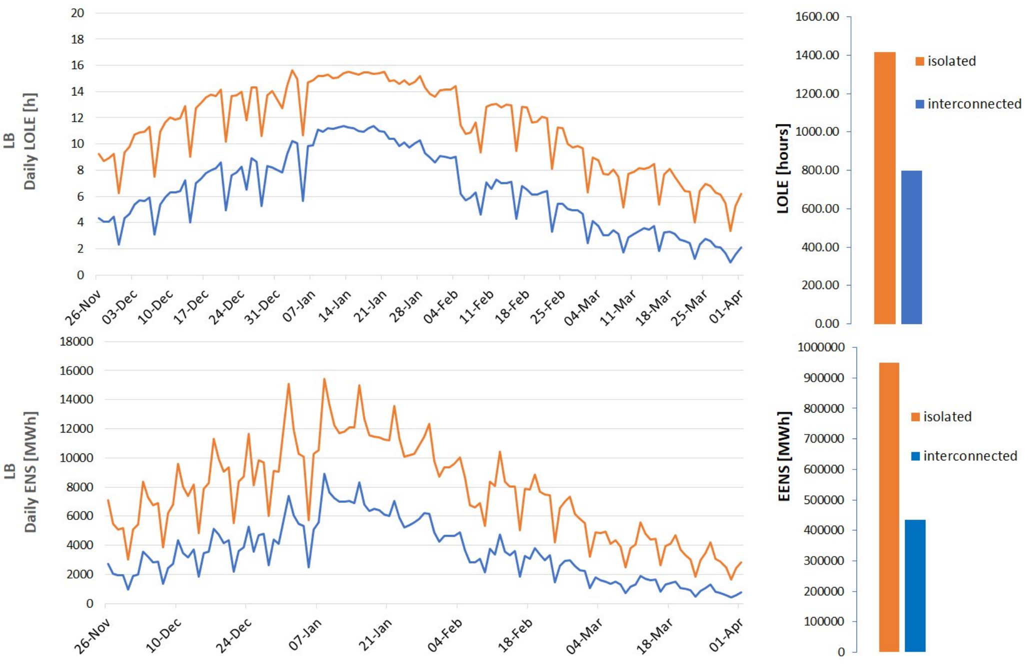


Figure 37: Daily LOLD and ENS for the interconnected and isolated mode of operation

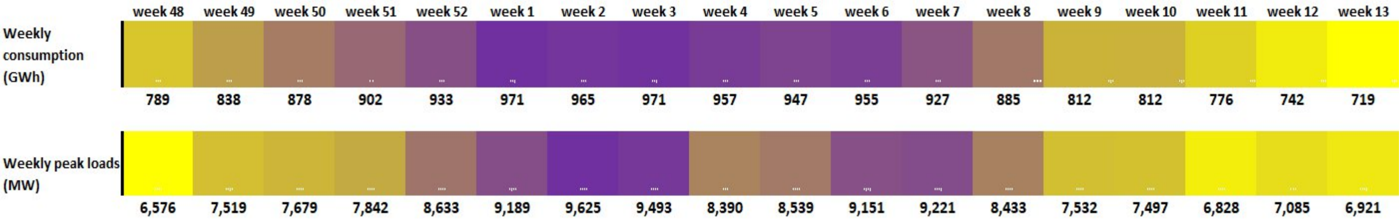
In the case of isolated operating mode, LOLE and EENS are even higher. Interconnection with Jordan helps, but cannot solve all adequacy issues.

4.5 Libya

DEMAND

Libya's seasonal weekly demand, depicted in Figure 38, goes from around 718 GWh to 971 GWh, while peak hourly demand each week goes from 6576 MW to 9625 MW. This variation of the peak load is almost 50% which is very high. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in January and February, (1st – 6th week). The maximum hourly demand in all 38 MC years reaches 9625 MW in the 2nd week of 2023.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	789	838	878	902	933	971	965	971	957	947	955	927	885	812	812	776	742	719
Weekly peak loads (MW)	6,576	7,519	7,679	7,842	8,633	9,189	9,625	9,493	8,390	8,539	9,151	9,221	8,433	7,532	7,497	6,828	7,085	6,921

Figure 38: Seasonal Weekly demand in Libya

SUPPLY AND NETWORK OVERVIEW

Libya's generation portfolio is based exclusively on gas-fired power plants, with 100% in generation capacity mix. The majority of installed thermal capacities refer to plants with open-cycle gas turbines (56%) and combined cycle gas turbines (26%), while only 16% of capacities mix corresponds to conventional gas-fired power plants. It should be emphasized that according to provided data for winter outlook 2022/2023 there are no RES capacities installed in Libya. In addition, less than 5% of peak load refers to net import transfer capacities.

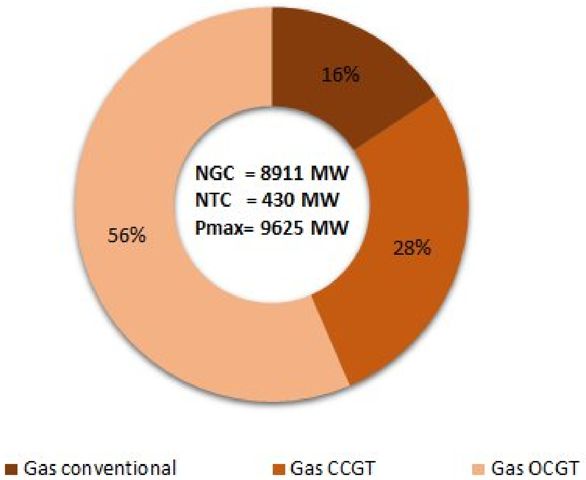


Figure 39: Installed Capacity mix with total NGC, import NTC and peak demand in Libya

The average daily available TPP capacity, after reduction due to planned and forced outages, is shown in Figure 40. 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 TPP capacities level is stable but grows moving from 2022 to 2023, since 1188 MW of gas fired power plants will be commissioned on 01/01/2023, according to provided input data. Therefore, for the winter months (November-December) in 2022, the average available thermal capacity is stable at the level of 6600 MW, while for the winter months in 2023 (January-March), the available thermal capacity is around 7600 MW.

The minimal daily available TPP capacity between all analysed MC years is between 4537 MW to 6281 MW, which is significantly lower compared with the peak demand of 9625 MW.

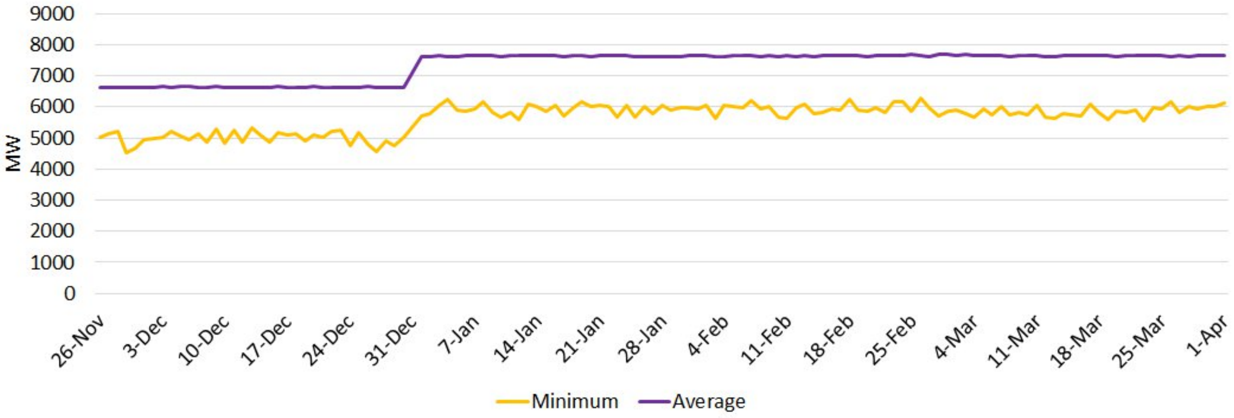


Figure 40: Average and minimum TPP available capacity in Libya

As a result of system simulation, the minimum hourly TPP margin for each day is calculated and depicted in Figure 41. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on each day is at zero till the end of February. From March, this margin is a little bit higher due to a decrease in demand. However, there are only a few days with non/zero minimum daily margin in March.

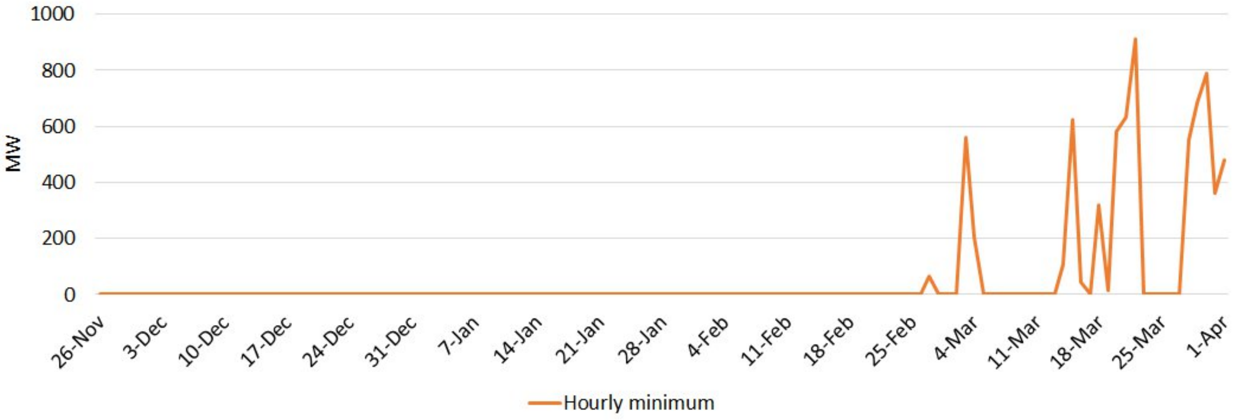


Figure 41: Minimum hourly TPP margin on each day of the analysed period in Libya

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 42, 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 concluded, that shape of daily LOLE/EENS is very similar in both analysed regimes of operation (interconnected and isolated). This is because the difference between ENS in the two analysed regimes corresponds approximately to total imports from Tunisia and Egypt.

As total consumption in Libya increases moving from November to January, energy not supplied increases as well. On the other hand, after the 1st of January 2023, an additional 1188 MW in gas fired power plants will enter into operation reducing daily LOLE below 1 hour in the interconnected case and below 2 hours in isolated operational mode. In the case of the isolated mode of operation, adequacy risk is very high, with daily LOLE above 4 hours.

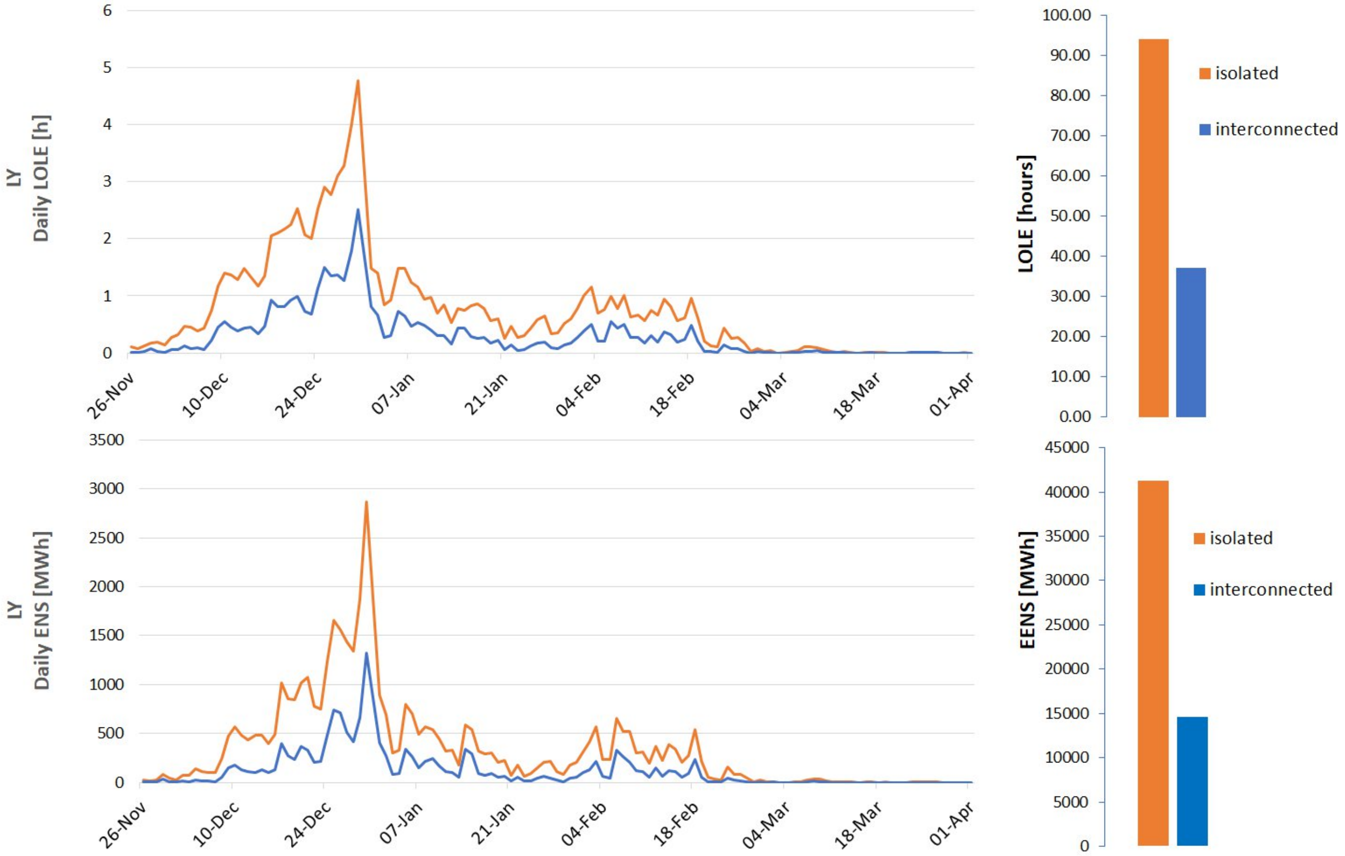


Figure 42: Daily LOLD and ENS for the interconnected and isolated mode of operation

Maximum hourly shortage in supply during the winter season in the interconnected mode of operation and within all 684 MC years is high - 2620 MW (This happens in week 2 in only one MC year, in the hour with high demand and big units in either planned or forced outage).

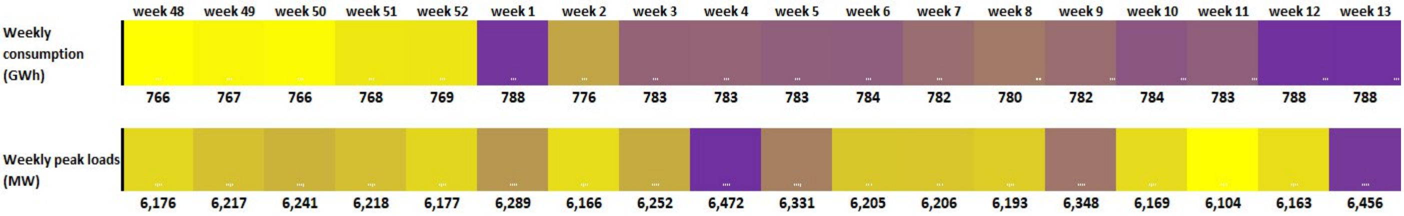
At the right-hand part of the figure, LOLE and EENS for the entire season for the interconnected and isolated mode of system operation are given. LOLE for the entire season in the isolated case is above 90 hours, while for the interconnected regime of operation seasonal LOLE is significantly lower (around 37 hours). Energy not supplied in the interconnected case is around 3 times lower compared to the isolated case, which emphasizes the importance of interconnections.

4.6 Morocco

DEMAND

Moroccan seasonal weekly demand, depicted in Figure 43 goes from around 766 GWh to 788 GWh, while peak hourly demand each week goes from 6104 MW to 6472 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in January, as well as in the two last weeks of March (12th - 13th week). However, total consumption from January to March is pretty much constant. The maximum hourly demand in all 38 MC years reaches 6472 MW in the 4th week of 2023.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	766	767	766	768	769	788	776	783	783	783	784	782	780	782	784	783	788	788
Weekly peak loads (MW)	6,176	6,217	6,241	6,218	6,177	6,289	6,166	6,252	6,472	6,331	6,205	6,206	6,193	6,348	6,169	6,104	6,163	6,456

Figure 43: Seasonal Weekly demand in Morocco

SUPPLY AND NETWORK OVERVIEW

Moroccan power generation fleet is balanced and well-diversified in comparison with other analysed 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 18% and 10% respectively. Total installed capacities are 12001 MW with total import capacity up to 1500 MW, which is about 23% of peak load in the analysed period.

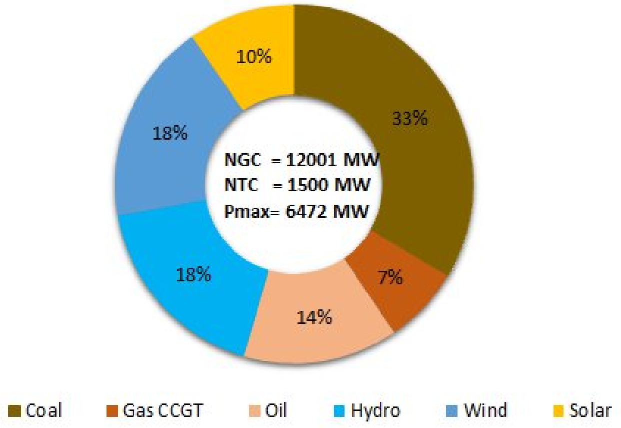


Figure 44: Installed Capacity mix with total NGC, import NTC and peak demand in Morocco

The average daily available TPP capacity, after reduction due to forced and planned outages, is shown in Figure 45. 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 level is stable, and it is around 5200 MW during the entire season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 2375 MW to 3583 MW.

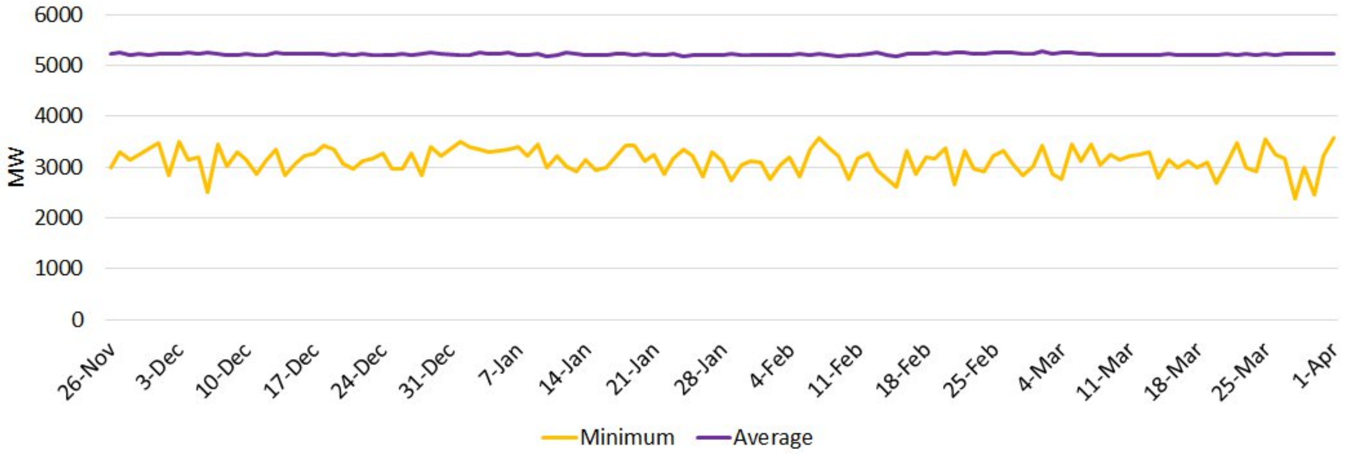


Figure 45: Average and minimum TPP available capacity in Morocco

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 engaged TPP capacities. Obviously, no margin in TPPs exists in Morocco's power system, but adequacy is not endangered since there are other sources and interconnections to support adequacy.

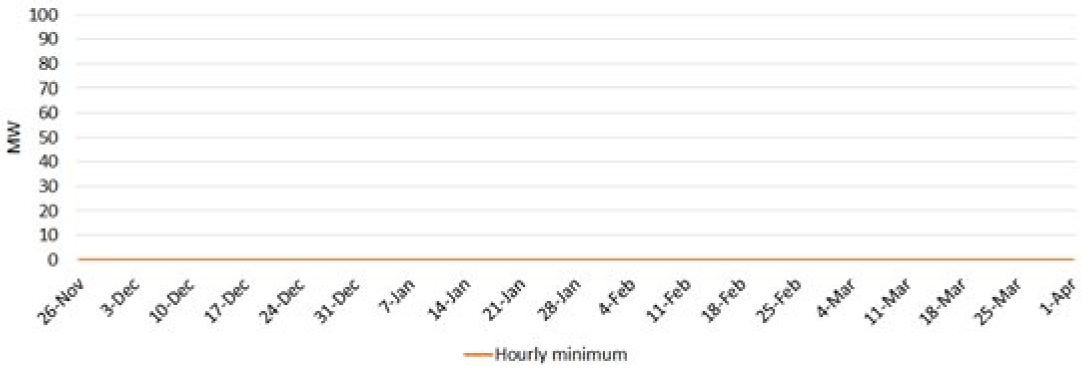


Figure 46: Minimum hourly TPP margin on each day of the analysed period in Morocco

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 47 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 2022/2023 in Morocco.

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

In the case of the isolated mode of operation, adequacy risk is present, with daily LOLE values above zero during the whole season (there are only a few days without any adequacy issues in March). On the other hand, a daily energy deficit between 5 MWh and 22 MWh is constantly present in December 2022, attenuating to zero till the end of March.

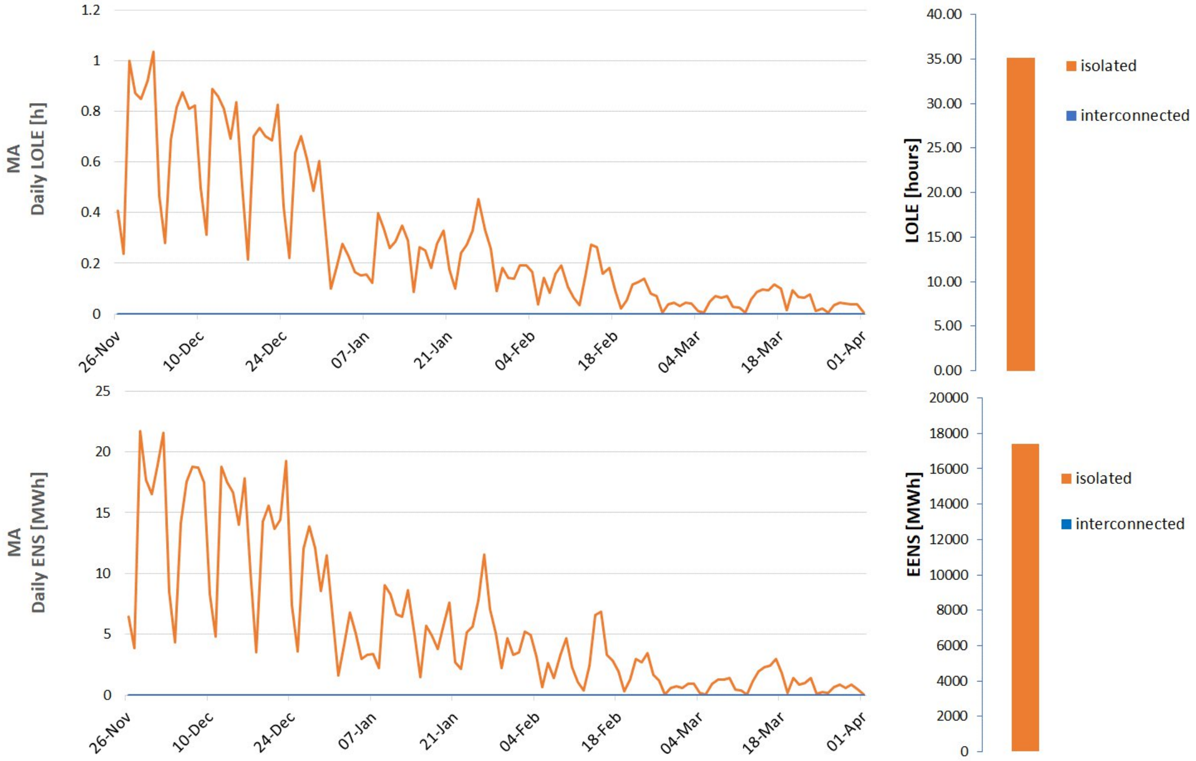


Figure 47: Daily LOLD and ENS for the interconnected and isolated mode of operation

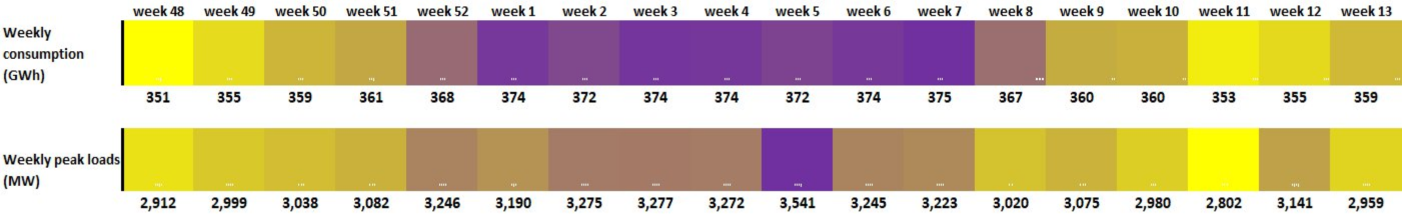
At the right-hand part of the figure, LOLE and EENS for the entire season for the isolated mode of system operation are given. LOLE for the entire season is about 35 hours, while EENS is less than 18 GWh.

4.7 Tunisia

DEMAND

Tunisian seasonal weekly demand, depicted in Figure 48, is rather constant (between 351 GWh and 375 GWh), while peak hourly demand each week goes from 2802 MW to 3541 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected from the end of December to the end of February. The maximum hourly demand is reached in the 5th week - 3541 MW, which is the maximum in all 38 climatic years.



	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	351	355	359	361	368	374	372	374	374	372	374	375	367	360	360	353	355	359
Weekly peak loads (MW)	2,912	2,999	3,038	3,082	3,246	3,190	3,275	3,277	3,272	3,541	3,245	3,223	3,020	3,075	2,980	2,802	3,141	2,959

Figure 48: 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 600 MW, while maximum hourly consumption is around 3541 MW.

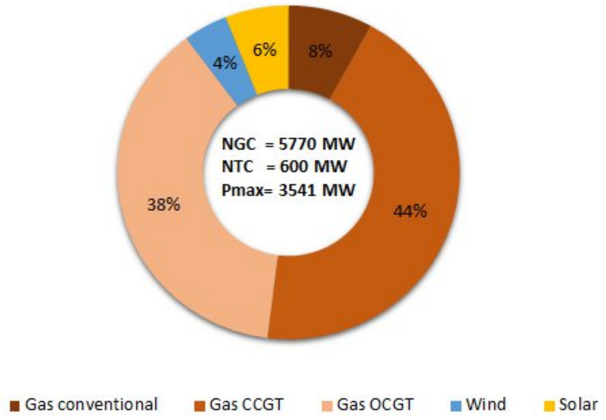


Figure 49: Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia

The average daily available TPP capacity, after reduction due to forced and planned outages is shown in Figure 50. 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 thermal available capacity (for all 684 MC years) is between 4290 MW and 4825 MW, which is higher than the expected peak load of 3541 MW during the winter season. However, the minimum average daily available thermal capacity (minimum among all 684 MC years for each day) is lower, with the lowest value of 2724 MW.

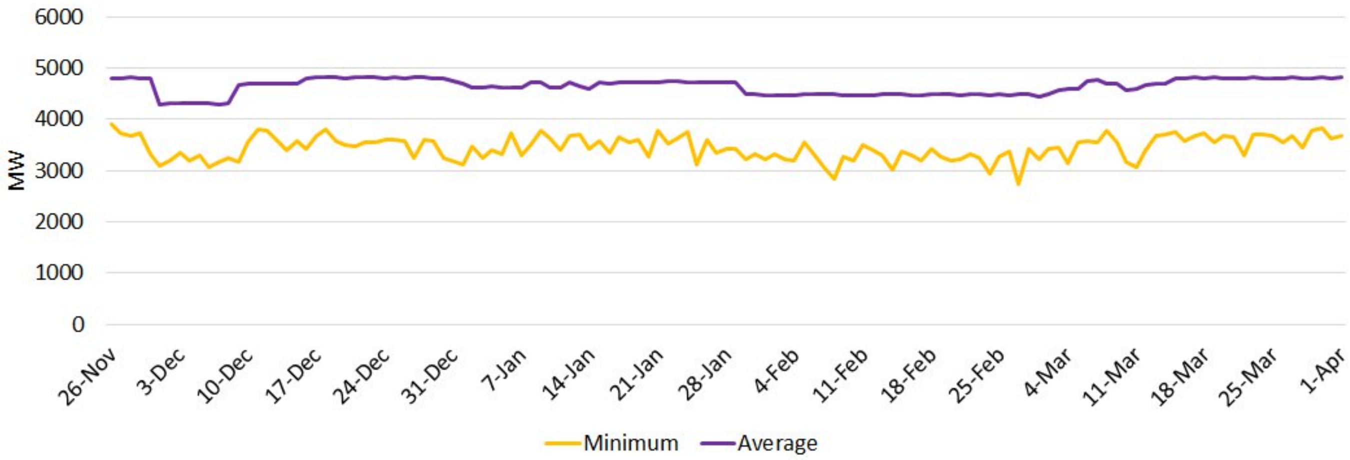


Figure 50: Average and minimum TPP available capacity in Tunisia

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 50. 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 one day at the end of January).

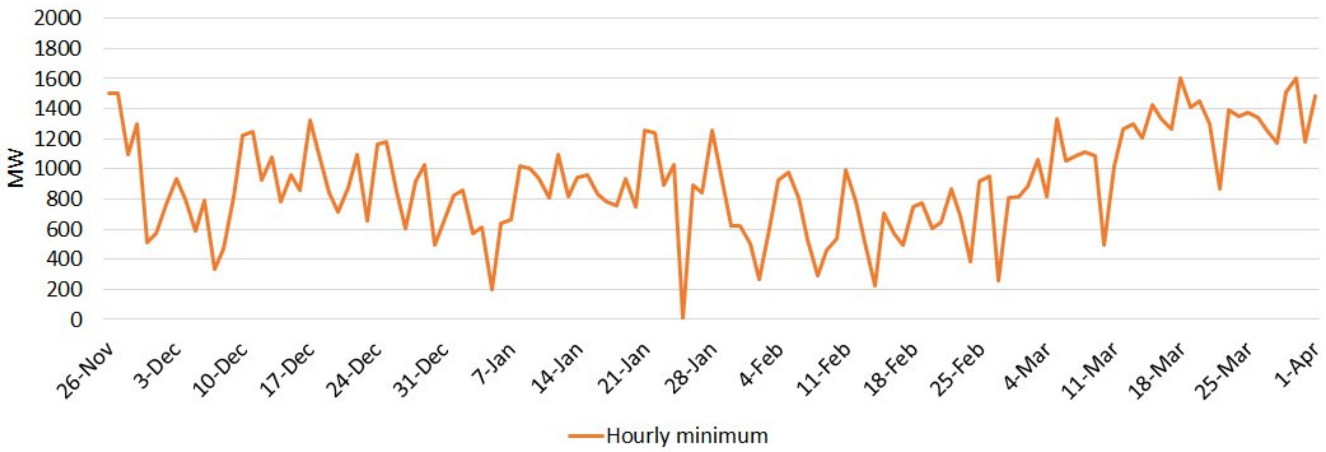


Figure 51: Minimum hourly TPP margin on each day of the analysed period in Tunisia

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 52 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 0.1 hour. In fact, only in a few days, there is a lack of energy, always below 3 MWh.

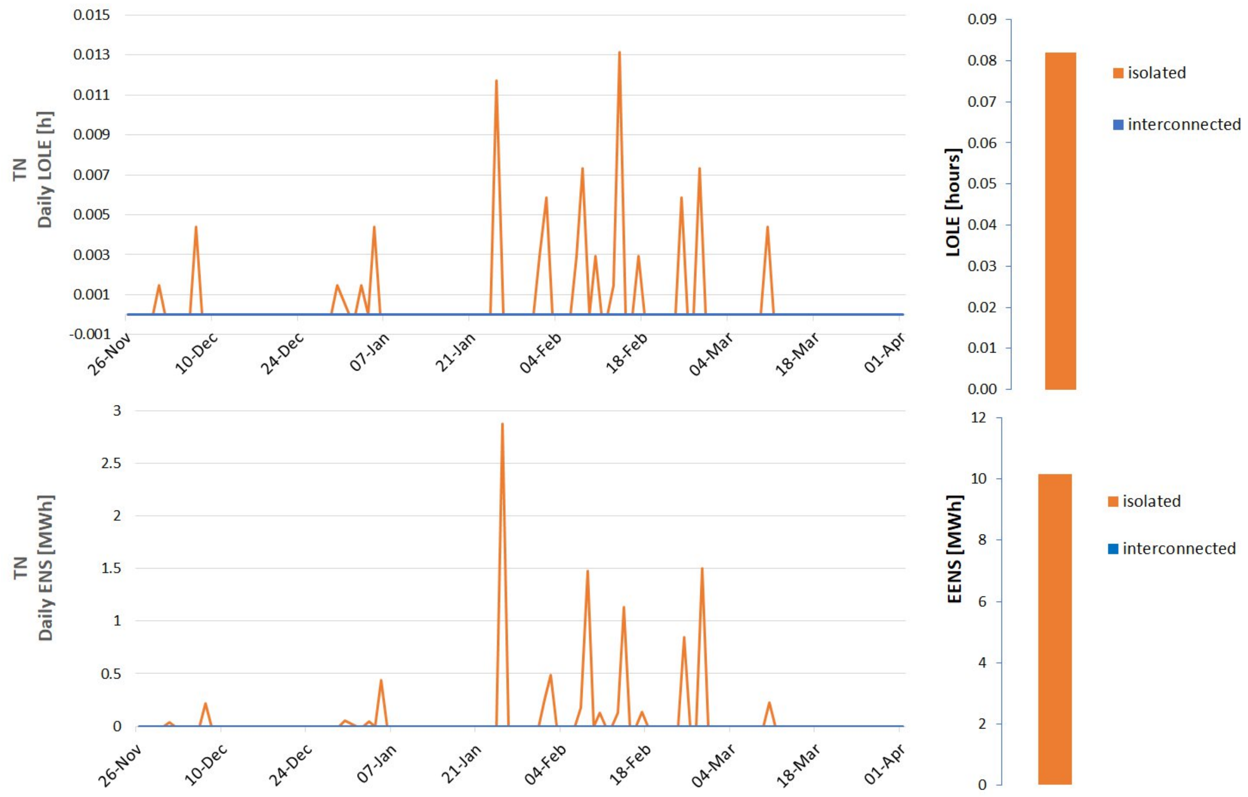


Figure 52: Daily LOLD and ENS for the interconnected and isolated mode of operation

At the right-hand part of the figure, LOLE and EENS for the entire season for both modes of system operation are given. Expected energy not supplied for all analysed MC years (i.e. EENS) is only 10 MWh for the entire winter season while LOLE is neglectable (around 0.08 hours). It should be emphasized that these low adequacy issues could be easily overcome if the requested reserve is reduced for a few MW.

Med-TSO Legal Headquarters - Viale Egidio Galbani,
70 – 00156 Rome – Italy • Info@med-tso.com • www.med-tso.com

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