



**LEBANON**

**SEPTEMBER 2021**

**World Bank – EDL – MEW**  
**LEAST COST GENERATION PLAN**

# LEAST COST GENERATION PLAN

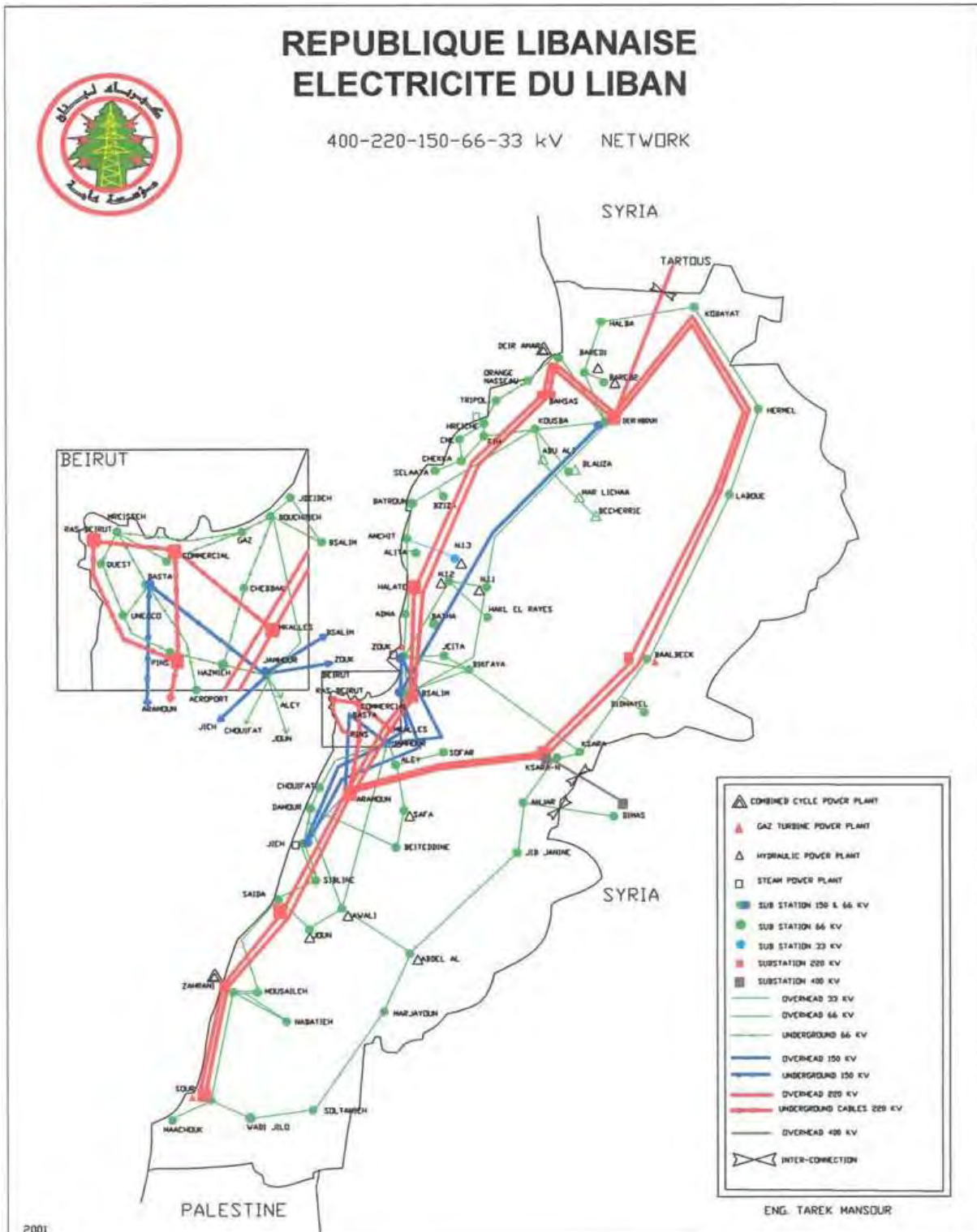
**SEPTEMBER 2021**

This study report presents a 10 year Least Cost generation plan for the Lebanese electricity generation system. It presents the results of a techno-economic optimization for a Base Case scenario, followed by a sensitivity analysis, to finally recommend an ambitious but realistic plan, which presents the least cost and reaches the optimal mix by 2030.





# REFERENCE MAP



Source: [http://www.geni.org/globalenergy/library/national\\_energy\\_grid/lebanon/lebanesenationalelectricitygrid.shtml](http://www.geni.org/globalenergy/library/national_energy_grid/lebanon/lebanesenationalelectricitygrid.shtml)



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## ABBREVIATIONS & ACRONYMS

<b>BOO</b>	Build Own Operate
<b>BOOT</b>	Build Own Operate Transfer
<b>BOP</b>	Balance of Plant
<b>CAPEX</b>	Capital Expenditure
<b>CCGT</b>	Combined Cycle Gas Turbine
<b>CDF</b>	Cumulative Distribution Function
<b>CDR</b>	Council of Development and Construction
<b>EAT</b>	Environment Abatement Technology
<b>EDF</b>	Electricité du France
<b>EDL</b>	Electricité du Liban
<b>EIA</b>	Environmental Impact Assessment
<b>EIB</b>	European Investment Bank
<b>EPC</b>	Engineering, Procurement and Construction
<b>FSRU</b>	Floating, Storage, and Regasification Unit
<b>GDP</b>	Gross Domestic Product
<b>GEP</b>	Generation Expansion Plan
<b>GIS</b>	Gas Insulated Substation
<b>GoL</b>	Government of Lebanon
<b>GT</b>	Gas Turbine
<b>Gwh</b>	Giga Watthour
<b>HFO</b>	Heavy Fuel Oil
<b>HHV</b>	Higher Heating Value
<b>HRE</b>	High Renewable Expansion scenario
<b>HRSR</b>	Heat Recovery Steam Generator
<b>IPP</b>	Independent Power Producer
<b>KJ</b>	Kilo Joule
<b>kV</b>	Kilo Volt
<b>kWh</b>	kilowatt-hour
<b>LCOE</b>	Levelised Cost of Electricity
<b>Lead time</b>	Time between NTP and commissioning date
<b>LFO</b>	Light Fuel Oil
<b>LHV</b>	Lower Heating Value
<b>LNG</b>	Liquefied Natural Gas
<b>MMBTU</b>	Millions of British thermal unit
<b>MEW</b>	Ministry of Energy and Water, Lebanon
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt-hour
<b>NG</b>	Natural Gas
<b>NPV</b>	Net Present Value
<b>NTP</b>	Notice To Proceed
<b>O&amp;M</b>	Operating and maintenance
<b>OEM</b>	Original Equipment Manufacturer
<b>OPEX</b>	Operational Expenditure
<b>PPA</b>	Power Purchase Agreement





<b>PPM</b>	Parts Per Million
<b>PPP</b>	Public Private Partnership
<b>RES</b>	Renewable Energy Sources
<b>SCR</b>	Selective Catalytic Reduction
<b>ST</b>	Steam Turbine
<b>TEP</b>	Transmission Expansion Plan
<b>VRE</b>	Variable Renewable Energy
<b>WB</b>	World Bank

## DEFINITIONS

<b>Capacity available during peak demand (summer)</b>	100 % of dispatchable power plants (ICE, ST, OCGT, CCGT, BIOGAS & CSP), 10% of HYDRO RoR, 9% of UTILITY SCALE SOLAR PV, 0% of DISTRIBUTED SOLAR PV, 7% of WIND and 96% of STORAGE (>4h) are considered available on peak load
<b>Capacity reserve margin (MW)</b>	Capacity available during peak load (MW) - Peak demand (MW)
<b>Capacity margin (%)</b>	Capacity reserve margin (MW) / Peak demand (MW)
<b>Unserved Energy Hours (h)</b>	Unserved Energy Hours is the total number hours in which there was any level of Unserved Energy
<b>LOLE (days)</b>	Equivalent Number of days with Unserved Energy (LOLP * 365)
<b>LOLP (%)</b>	Loss of load probability is the probability that demand will exceed the capacity of the system in a year
<b>Renewable generated energy (GWh)</b>	Energy generated by Renewable generators (HYDRO, SOLAR PV DISTRIBUTED SOLAR PV, CSP, WIND & BIOGAS)
<b>RE energy share (%)</b>	Renewable generated energy (GWh) / Served Energy (GWh)
<b>CO2 emission intensity (g/kWh)</b>	CO2 emission (tonne) / Served Energy (GWh)
<b>Capacity Factor (%)</b>	Generated energy over a year (GWh) / (derated capacity (MW) * 8760)
<b>Average Heat Rate (GJ/MWh)</b>	Fossil Fuels Offtake (TJ) / Generated energy over a year (GWh)
<b>Emissions Cost (\$000)</b>	CO2 emission (tonne) * Shadow Price of Carbon (\$/tonne)
<b>Total System Cost (\$/MWh)</b>	(Fuel Cost + VO&M Cost + Emissions Cost + Annualized Build Cost + FO&M Cost + Retirement Cost) / Served Energy (GWh)
<b>Generation Cost (\$/MWh)</b>	(Fuel Cost + VO&M Cost + Emissions Cost) / Served Energy (GWh)



## 1. EXECUTIVE SUMMARY

This report presents an analysis of Lebanon’s options for developing its generation capacity over the next 10 years on a least-cost basis. It presents the optimization results of Base Case and several scenarios that test the sensitivity of the results based on variation in certain key assumptions. The Base Case and sensitivity scenarios are selected to model a key policy consideration: the impact of the constraints on the level of penetration of renewable technologies, especially solar and wind, on the optimal generation portfolio in the country to inform decisions that must be made within a very short time on urgently needed investments in new generation to remedy the existing supply shortage. The key result of these scenarios is that the initial investments should contain a mix of renewable energy (PV and wind), pumped hydro storage, and new gas-fired generation capacity at Deir Ammar and Zahrani sites. The results of the analysis concerning the investments beyond the immediate ones should be interpreted as indicative of policy directions to consider. While the optimal plans presented in this study indicate specific levels of investments in the various generation technologies over the entire planning horizon, these plans will need to be continually updated to reflect and adapt to the changing conditions of the country and the sector as they evolve over time.

Currently, Lebanon has a severe mismatch between electricity supply and demand. It is, therefore, imperative to increase the generation capacity as soon as possible to mitigate this mismatch and ensure adequate supply to consumers in a least-cost and environmentally optimal manner. The optimal plans, which are the result of the analysis presented in the report, envisage (a) decarbonizing the sector by transitioning its generation fleet from Heavy Fuel Oil (HFO) and diesel, as the main generation fuel, to natural gas and (b) integrating significant renewable energy (RE) capacity into the generation mix based on least-cost considerations.

The analysis in this study orients the system towards natural gas and RE as its main generation capacity contributors. The resulting generation mix will have a baseload gas demand of approximately 3.5 BCM/year starting in 2025 and will entail no RE curtailment on an average day. It will reach a capacity margin of 10% by 2028 for Base Case (2026 for HRE) and remain above this threshold for the remainder of the time horizon of the analysis. Spinning reserve will be adequate from 2025 onwards, with sizable reliance on storage units. This leads to huge improvements in carbon intensity and cost of electricity generation, dropping CO<sub>2</sub> emission intensity and total system cost over time from 665 kg/MWh and 130.52 US\$/MWh in 2019 to 263 kg/MWh and 74.26 US\$/MWh in 2030, respectively, in the Base Case scenario (in the HRE scenario to 249 kg/MWh and 73.85 US\$/MWh, respectively) by 2030. RE penetration will increase from 4% in 2020 to 32% in the Base Case and 35% in the “High Renewable Energy” (HRE) scenario in 2030. As such, HRE is more cost-effective for the country in the longer term. This does not take into consideration the potential environmental or health benefits from higher RE penetration in the HRE scenario.

Both the Base Case and HRE scenario consider additional brownfield thermal generation capacity at Deir Ammar, Zouk, Jieh and Zahrani, and greenfield thermal generation at Selaata. Brownfield development of combined-cycle power plants at Zouk and Jieh were not found to be least-cost because of the additional cost of fuel to the sites when compared to the alternatives, particularly RE generation. New gas-fired combined cycle power plants at Deir Ammar and Zahrani proved to be least-cost because of transmission access and ease of fuel supply, particularly when combined with existing generation at the same sites.

Both the Base Case and HRE scenario assume certain constraints on RE development over the planning period. Base Case caps the amount of annual RE development that can be expected, and, while HRE is more aggressive, it also assumes certain limitations that decrease over time. The rationale for this approach is that a massive build-up of RE capacity over a short period of time may



be impeded by the current institutional and financial limitations. Potential consequences of generation shortages would be more pronounced should more aggressive assumptions be adopted that do not materialize. This approach also reflects the lack of a track record of performance for project-financed transactions in the country and a low level of investor confidence needed to support large scale RE investments. The RE capacity needed to provide the necessary baseload generation to close the current generation gap would far exceed the assumed new gas-fired generation needed because of the difference in capacity factors between these technologies. As such, for planning purposes, a more conservative posture was assumed that can be updated to reflect more favorable developments in addressing the current institutional and financial challenges over the next 1-2 years to increase anticipated RE penetration.

Because of the required time to undertake competitive procurements, arrange financing, secure fuel supply and complete construction, it is unlikely that any permanent generation solutions can be installed and commissioned earlier than 2024. If, as a policy matter, generation is expected to significantly increase before then (especially if this is tied to a potential tariff increase), temporary solutions must be introduced to provide the generation capacity needed until the permanent plants can be deployed. If deployment of permanent generation is delayed, then the temporary solutions would have to be extended accordingly, as has been the case over the past several years. It may be possible to avoid these temporary solutions by maintaining the status quo, with consumers relying on existing small private distributed diesel-fired generators for much of supply that cannot be provided by EDL. However, aside from the significantly higher environmental impact of diesel generation in dense urban settings, this approach is likely to be at a much higher cost when compared to centralized large scale rented power plants and would push the additional higher cost of this capacity to consumers. It would also make less publicly acceptable any plans to increase EDL's tariffs in the short-term, as it would essentially increase electricity costs for consumers at a time of deep economic distress.

As previously noted, to assess robustness of these results, four (4) additional scenarios were undertaken to test sensitivity of the Base Case outcome to variation to certain key assumptions. First, a scenario was analyzed where carbon pricing was introduced based on both World Bank and European Investment Bank (EIB) forecasts. This would represent a shift in public policy to adopt a more proactive policy towards climate change mitigations, which would be a change in the current status quo. Second, a scenario was analyzed where the Base Case and HRE scenarios' assumption of static demand growth (largely 3 percent annually) was changed downward. Given available data that indicates a significant dip in demand in 2020 and 2021, it seems more realistic to fix demand at current levels until the end of 2025, except for 2022 where a dip of 4 percent is introduced to account for consumers' reaction to an increase in tariffs and EDL generation supplies. Afterwards, demand projections resume at their fixed 3 percent growth rate from 2026 onwards. Third, a scenario was analyzed where potential institutional and other constraints assumed in the Base Case and HRE scenarios were relaxed to test potential unconstrained RE growth potential within the planning horizon. A further variation on this sensitivity was analyzed where both carbon pricing and unconstrained RE growth were combined to see the potential impact on thermal and RE scale-up. Fourth, a last scenario was analyzed where thermal generation growth rate was constrained annually to 1 GW of new capacity, reflecting possible constraints on availability of financing.

These sensitivities lead to some interesting observations:

- With respect to RE penetration, removing constraints on annual RE growth rates results in the same level of RE penetration as HRE (35 percent), which itself is only 3 percent higher



than the Base Case. This is due to the fact that the techno-economic optimum, defined by the hypotheses of the study, is reached.

- More significant RE scale-up is achieved when adopting carbon pricing policies (RE penetration increases to 41 percent) and when combining these policies with unconstrained annual RE growth (RE penetration increases to 54 percent, if World Bank carbon pricing forecasts are used, and 68 percent, in case of EIB's). It is important to note, however, that such a significant increase in RE penetration, requiring doubling of RE energy in the system when compared to the Base Case, is expected to have significantly increased transmission costs associated with it (which will be tested in the next phase of this study) and, as of yet, seems unprecedented in an electric system.
- Constraining annual thermal generation investments to 1GW does not change the level of RE penetration from the Base Case. Instead, it is expected to increase the amount of temporary generation needed for a longer time and/or increase unserved demand.
- A third gas-fired combined cycle power plant (presumed at Salaata) is needed in all scenarios based on the assumptions with respect to demand and RE growth rate, except in the case of adopting carbon pricing coupled with unconstrained annual RE growth. This is largely because of (a) limited available land at the Deir Ammar and Zahrani sites for new generation, (b) the need for baseload generation in a short period of time and (c) the two assumed 2x1 and 3x1 configurations for all new thermal power plants. This conclusion may change in the final report that would present the final least-cost generation plan, once transmission costs are analyzed in the next phase of this study and the system cost of connecting the third plant at a greenfield site is taken into consideration.

Finally, it is important to note that there are currently certain regional developments that could potentially have significant impact on Lebanon's least-cost generation path. Egypt, Jordan, Syria and Lebanon are currently in advanced discussions about Lebanon's purchase of Egyptian gas and Jordanian electricity through Syria. These trades will use existing transmission lines (though the Syrian portion was damaged during its civil war and is currently being repaired) and the Arab Gas Pipeline (AGP). This will have a positive impact on available options for increasing generation capacity in Lebanon and diversifying its sources of supplies without significant capital investments in new assets. In respect to gas, for example, availability of supplies from Egypt at Deir Ammar through AGP would obviate the need to install a new floating gas import terminal, as assumed in this study. A floating terminal would still be needed at Zahrani until a north-to-south national gas transmission pipeline is completed to link Deir Ammar with Zahrani. Electricity purchases from Jordan will also add more generation capacity in EDL's system without having to resort to temporary generation or capital investments in new power plants in the short-term.

However, as it is unclear at this stage under what terms these potential trades will take place, they are not taken into consideration in this study. Nonetheless, the study assumes availability of Liquefied Natural Gas (LNG) at Deir Ammar. In this respect, availability of pipeline gas from Egypt at that location, which is expected to be less expensive than LNG, would only bolster the study's conclusions about priority of gas-fired generation in the least-cost mix. It would also lead to a lower overall system cost of power than the recommended approach in this study. Moreover, availability of electricity from Jordan has a similar impact as reduction of demand on the transmission grid from an analysis perspective. The study already takes into consideration the impacts on the least-cost mix in the low-demand growth scenario, though some consideration will be made in the transmission analysis to see the potential impact on transmission upgrades needed to facilitate the sale.



Nonetheless, it is also important to note that benefits from Jordan’s electricity supply will depend on prices agreed for the sale and wheeling of this energy to Lebanon and whether Lebanon adopts recommendations of this study for the least-cost generation expansion path, which, if pursued, is expected to significantly lower EDL’s overall system costs.

The table below gives an overview of all the proposed commissioning and decommissioning projects for the duration of the plan:

Site	Investment	Base Case		High Renewable Expansion Scenario		WB Carbon Pricing		EIB Carbon Pricing		Low Demand Growth		Progressive Thermal Investments	
		Capacity (MW)	Budget (2019 \$1M)	Capacity (MW)	Budget (2019 \$1M)	Capacity (MW)	Budget (2019 \$1M)	Capacity (MW)	Budget (2019 \$1M)	Capacity (MW)	Budget (2019 \$1M)	Capacity (MW)	Budget (2019 \$1M)
Deir Ammar	Addition of a FSRU	yes	752	yes	752	yes	752	yes	752	yes	752	yes	752
	Switch the existing CCGT to NG	yes	0	yes	0	yes	0	yes	0	yes	0	yes	0
	Tri-fuel CCGT 3x1	825	660	825	660	825	660	825	660	825	660	825	660
	Tri-fuel CCGT 2x1	550	444	0	0	550	444	550	444	0	0	550	444
	Internal Combustion Engine (Dual Fuel)	0	0	249	220	0	0	0	0	0	0	0	0
Selaata	Pipeline from Deir Ammar to Selaata	yes	165	yes	165	yes	165	yes	165	yes	165	yes	165
	Tri-fuel CCGT 3x1	825	660	825	660	825	660	825	660	825	660	825	660
Zouk	Retirement of the old Steam Turbines	yes	36	yes	36	yes	36	yes	36	yes	36	yes	36
Zahrani	Addition of a FSRU	yes	752	yes	752	yes	752	yes	752	yes	752	yes	752
	Switch the existing CCGT to NG	yes	0	yes	0	yes	0	yes	0	yes	0	yes	0
	Tri-fuel CCGT 3x1	825	660	825	660	825	660	825	660	825	660	825	660
	Internal Combustion Engine (Dual Fuel)	16.6	15	249	220	0	0	0	0	0	0	16.6	15
Jieh	Retirement of the old Steam Turbines	yes	20	yes	20	yes	20	yes	20	yes	20	yes	20
Solar PV		2 000	1 312	3050	1 994	2 000	1 312	2 000	1 312	2 000	1 312	2 000	1 312
Wind		790	948	430	516	1400	1 680	1400	1 680	530	420	790	948
Joun Pumped Hydro Storage	Upgrade to PHS	+49 MW/4h	21	+49 MW/4h	21	+49 MW/4h	21	+49 MW/4h	21	+49 MW/4h	21	+49 MW/4h	21
Battery Energy Storage System		+201 MW/213 MWh	95	+246 MW/246 MWh	112	+349 MW/349 MWh	159	+406 MW/406 MWh	184	+229 MW/229 MWh	104	+227 MW/230 MWh	104
<b>Total</b>			<b>6 540 M\$</b>		<b>6 788 M\$</b>		<b>7 321 M\$</b>		<b>7 346 M\$</b>		<b>5 562 M\$</b>		<b>6 549 M\$</b>

Table 1: Investments summary table



## 2. OBJECTIVE

The current Lebanese electrical system suffers from a lack of generation capacity which causes an imbalance between supply and demand. It is necessary to develop new generation plants to compensate for this gap and continue to follow a potential increase in electricity demand.

Increasing generation capacity and integrating renewable energy in the electricity mix incurs multiple challenges for the coming years. Seeing as Lebanon's power plants are getting old and require replacement by any measure, one must seize the opportunity to rethink the generation mix so that it could accommodate a high RE penetration (at least 30% by 2030 as per the Government's target), diversify its energy sources (NG, while relying on HFO for backup), improve its quality of service, and achieve self-sufficiency while reducing the cost for the final consumer.

The objective of this report is to present an optimal 10-year (2020-2030) electricity generation plan for Lebanon. This plan optimizes for cost as well as fulfilling demand, under specific constraints and assumptions. A planning exercise is fundamentally based on current knowledge and future projections. Inherent to the nature of such an exercise is an uncertainty concerning the projections. Therefore, after presenting a base case scenario, this study applies variations on key uncertain variables (such as: RE expansion rate, demand growth and carbon pricing) thus constituting a sensitivity analysis around the base case. The planning horizon for this study is 2020-2030, but may be shifted with little to no adjustment, if necessary, depending on the start date of its implementation.

The source of data concerning the current status of generation in Lebanon is the "Data Collection Report" written by EDF and approved by the WB, MoEW, and EDL. Said report is included in the appendix of this document.

This plan uses tri-fuel CCGTs so that the system may use HFO as backup in case of delays in the installation of the NG infrastructure or lack of NG supply in the upcoming years.



## 3. OPTIMISATION CONTEXT

### 3.1. METHODOLOGY

The optimization model consists of two main modules:

- The first module is the Long Term Plexos module. It will search the set of candidate projects for the optimal combination of new builds and retirements so as to come up with the least-cost expansion plan, through minimizing the Net Present Value of investment and operation costs. It will account for build costs, retirement costs, lead time for new builds, fuel costs, O&M costs, cost of unserved energy, etc. The optimization is conducted on computation blocks. The days of each month are averaged to give a representative day of the month which is divided into 24 hours, each corresponding to one computation block ( $12 * 24 = 288$  load blocks per year).
- The second module is the Short Term Plexos module. It optimizes the generation dispatch between 2020 and 2030 on an hourly basis. This module implements a system stability constraint and optimizes the generation dispatch to minimize a cost function subject to all operational constraints. Its output is the generation dispatch between assets, served vs unserved energy, CO<sub>2</sub> emissions and fuel consumption.

The input data representing the current state of generation in Lebanon is based on the data provided by EDL, and stated in the “Data collection report”. Techno-economic details concerning each generation unit were sourced from multiple past works, experiences and manufacturer datasheets.

It is worthy of note, however, that even though the model outputs an optimal build, retirement and dispatch plan, this model operates under perfect knowledge constraints. This means that it operates as if it already knows how demand will evolve over the next 10 years. This and other simplification assumptions mean that the model’s forecast will vary from reality increasingly, the further we look into the future. This especially concerns dispatch, as real-world constraints will affect dispatch decisions.

### 3.2. ASSUMPTIONS

This section briefly summarizes the assumptions made in this report. The full details about these assumptions are included in the data collection report in the appendix.

#### 3.2.1. DEMAND FORECAST

As long as the public supply has not reached a 24-hour continuous service and the consumers have not adapted their behavior accordingly, no accurate estimation of the demand may be achieved.

Demand for the year 2019 reached ~24 247 GWh with a peak load of ~3 844 MW. The demand for 2020 is estimated around 24 339 GWh with a peak load of 3 773 MW. For the base case of this study, the demand is projected to grow by 3% annually between 2020 and 2030 with a dip of 8% for the year 2022, following an increase in supply hours and a substantial tariff raise as aligned with the Government's plan. However, due to the uncertainty surrounding the demand in Lebanon, these numbers must be subjected to a revision on a yearly or bi-yearly basis by the system operators. Moreover, it should be noted that the assumed load factor (annual average load/annual peak load) of 74% is relatively high compared to neighboring countries. Such a high load factor is more suitable for countries with a high share of industrial load.

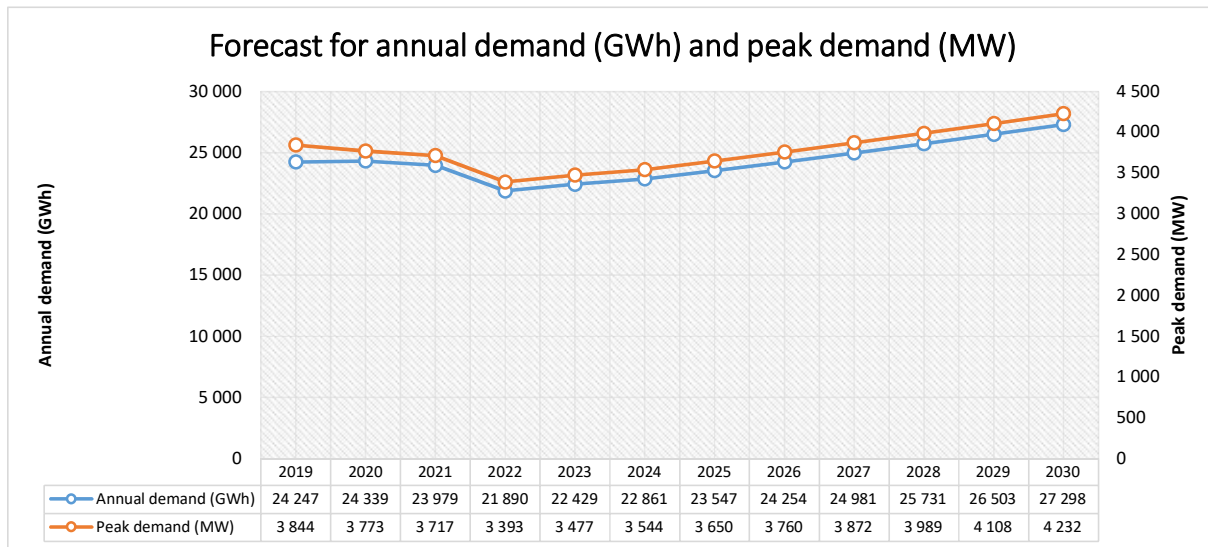


Figure 1: Forecast for annual demand (GWh) and peak demand (MW)

### 3.2.2.GENERATION EXPANSION CANDIDATES

The government has set a constraint of 21/24h supply to increase the EDL tariffs by 2022. This milestone sets a very tight action window. Therefore, rental solutions are considered to cater for the short-term demands.

Project candidates for the generation expansion include rentals, OCGTs (E&F), CCGTs (2x1 E, 3x1 E & 2x1 F), ICEs (Dual fuel where NG and HFO are available, NG (HFO) fired where NG (HFO) only is available), RoR Hydro, Utility scale & distributed Solar PV, CSP, Wind farms, Battery Energy Storage Systems and Pumped Hydro Storage.

The expansion rate of Solar and Wind generation is limited to 250 MW/yr and 200 MW/yr respectively, as suggested by the MoEW, for the Base Case. Meanwhile a high RE expansion scenario, presented in the sensitivity analysis, supposes an increasing rate for these projects. This increase is attributed to the growth of expertise in RE installations in Lebanon and to the gain of investor confidence in the years to come.

RE\Year	2021*	2022*	2023	2024	2025	2026	2027	2028	2029	2030
Solar PV (MW/yr)	180	0	250	250	250	250	250	250	250	250
Wind (MW/yr)	0	226	0	200	200	200	200	200	200	200

\* Projects committed by MEW

Table 2: Solar and Wind expansion rates





### 3.2.3. GENERATION RETIREMENT CANDIDATES

The optimization considers the possibility of decommissioning the Zouk and Jieh power plants, with the respective decommissioning times of 1 year and 2 years.

### 3.2.4. FUEL INFRASTRUCTURE CANDIDATES

To supply NG fired units LNG infrastructures will be considered in this study. These include FSRUs (Beddawi, Selaata and Zahrani) and pipelines (to Selaata, Zouk, Jieh and Sour). Since Deir Ammar and Zahrani already have NG plants, this study will consider the FSRUs committed for these two sites, and optimize their installation date, with regards to the state of existing and new power plants. All other NG investments are subject to optimization.

### 3.2.5. FUEL COST

Below is the fuel cost projection for both scenarios. This projection does not include storage and transport costs, which need to be accounted for in the case of Hrayche, Baalback and Sour. Specifically, an overcost of 9.5 \$/HFO ton, 19 \$/LFO ton and 5 \$/LFO ton need to be added for Hrayche, Baalback and Sour respectively.

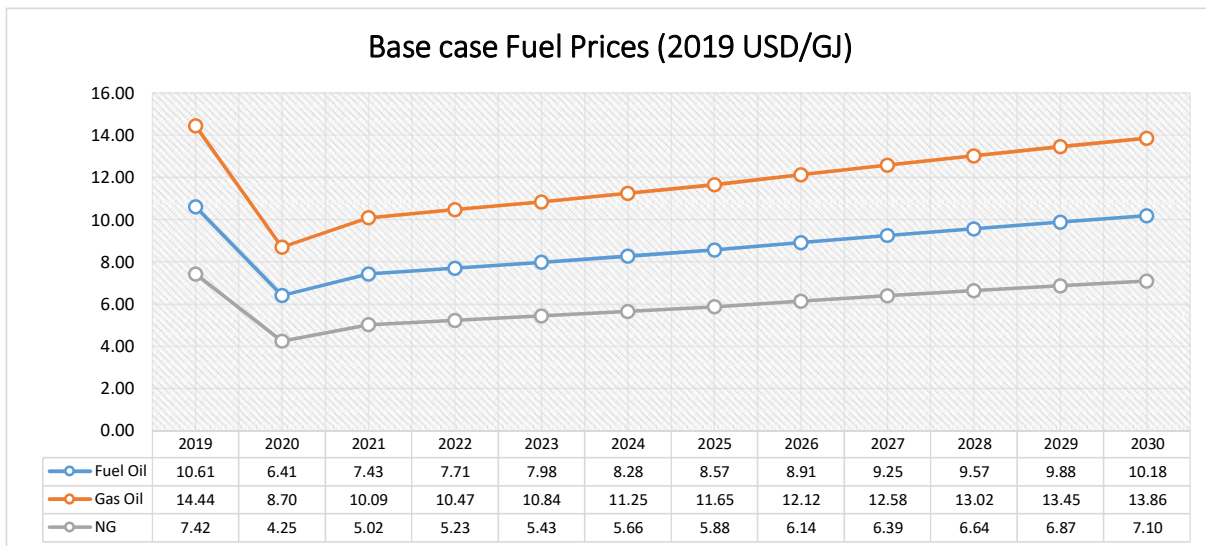


Figure 2: Fuel prices in energy terms (2019 USD/GJ)

### 3.2.6. FREQUENCY CONTAINMENT RESERVE

The minimum provision for Frequency Containment Reserve (FCR) must be at least equal to the generation power lost during the largest N-1 event. The lost power is that of one Gas turbine as well as its corresponding heat recuperated by the steam turbine. For instance:

- For a class E unit, minimum required provision = 190 MW (GT) + 88 MW (ST) = 278 MW;

All dispatchable generators (existing and new; except for rental generators) are expected to participate in the primary reserve (Maximum spinning reserve response factor of 10%).

Due to the consideration that rental power plants are used temporarily to reduce the gap between the demand and generation capacity, they are not required to participate in the reserve provision.

In case of a reserve shortage a penalty cost of 630 \$/MWh (Value of Reserve Shortage, VoRS = 90% x VoLL, with VoLL = 700 \$/MWh) is incurred.



### 3.2.7. CAPACITY RESERVE MARGIN

In this analysis, a Capacity Reserve Margin (CRM) of around 10%, on top of the system demand, must be set to ensure system reliability. The capacity margin is meant to respond to peak demand as well as unplanned outages. In other words, capacity margin is a dispatchable backup generation capacity meant to meet peak demand in case of low solar and wind generation and/or forced N-1 events. Therefore, it is essential that this capacity margin be computed based only on available and forecastable generation capacity, i.e. sources that can be relied upon.

This Capacity Reserve Margin requirement adds a new constraint to our Plexos model, in addition to the FCR constraint. Plexos will choose the maximum between (Peak Demand + CRM) and (Peak Demand + FCR).

Renewable generation units (Solar PV and Wind) can contribute to this capacity during peak demand. But due to their non-dispatchability and uncertainty of forecast a statistical approach is adopted to compute their contribution (ref. Data Collection Report). The following table shows the solar and wind firm capacity during peak hours per season:

	PV firm contribution to peak demand	Wind firm contribution to peak demand
<b>Fall (Sept, Oct &amp; Nov)</b>	2%	3%
<b>Spring (March, April &amp; May)</b>	0%	4%
<b>Summer (June, July &amp; Aug)</b>	35%	19%
<b>Winter (Dec, Jan &amp; Feb)</b>	0%	0%
<b>Average</b>	9%	7%

*Table 3: Solar and Wind Contribution to peak hours*

### 3.2.8. SHADOW PRICE OF CARBON

Carbon tax or Shadow Price of Carbon (SPC) has been adopted in numerous countries around the world as a means of incentivizing energy-efficiency and renewable energies. Under current regulations, the Lebanese government does not impose any SPC. It is most likely that this will remain the case for the foreseeable future. Therefore, the plan does not take into account any such SPC in the Base Case. An indicative cost breakdown that includes SPC (using SPC projections of the WB and the EIB) will be provided.

### 3.2.9. EMISSIONS & ENVIRONMENTAL MITIGATION MEASURES

The carbon emissions are defined per fuel type in the appendix. The study will employ the best available environmental mitigation measures (SCR for NG & HFO, fine filters for HFO only) for generation candidates in Deir Ammar, Zahrani, Zouk and Jieh, due to their pollutant levels having already exceeded the limits. For the remaining sites, the Environmental Social Impact Assessment will determine appropriate mitigations.



## 4. GENERATION PLANNING RESULTS

This section presents the least cost generation expansion paths, based on the assumptions and information jointly developed between all involved parties. It presents the results arranged in subsections covering:

- New and retired capacity
- Capacity reserve margin
- Generation mix
- Average annual capacity factor
- Unserved energy
- Emissions and fuel consumption
- Cost breakdown & budget estimates
- Spinning reserve requirements
- Maintenance scheduling
- Operability & renewable penetration

This report expands on the Base Case. Afterwards, it branches into a number of scenarios that constitute a sensitivity analysis around the Base Case. Finally, based on the sensitivity conclusions, this report details the least cost plan leading to the cheapest energy, lowest carbon footprint (with current regulations), ambitious but feasible energy mix for Lebanon.



## 4.1. BASE CASE SCENARIO

### 4.1.1. NEW AND RETIRED CAPACITY

The following tables depict the evolution of the key performance indicators for the generation plans within the horizon of this study. Recall that one of the main goals is to ensure 24h supply as soon as possible. However, the earliest NTP is scheduled no sooner than mid-2022. After applying the construction delay, we see that the earliest new non-rental project would not be ready before 2024. Therefore, the only valid way to increase production earlier than 2024 relies on rental solutions. This solution is only valid under the condition that the tariff increase MUST be accompanied by a ~21/24h supply. If this is no longer the case, i.e. if the tariff increase is no longer tied to ~21/24h supply and unserved energy can be tolerated until the commissioning of the permanent plants, then the rental generators are no longer required.

Note however that the assumptions given in the paragraph above are quite optimistic, be it about earliest NTP, or construction time. On the other hand, it would be extremely difficult to negotiate a short-term rental contract. So, it is not unreasonable to assume that, should the rental projects be undertaken, they will probably last for more than two years.

One might expect an increase in unserved energy seeing as the contract for the existing rental barges (Zouk and Jieh) expires by September the 30<sup>th</sup> of 2021, with no foreseen extension. However, the decrease in demand as discussed in §3.2.1, as well as the installation of new Solar (180 MW in 2021) and Wind (226 MW in 2022) farms, offsets the loss of production incurred by the departure of the barges, resulting in a net increase in the percentage of served energy in 2022.

### TEMPORARY SOLUTIONS

In light of the above, and under the current constraints, 1 030 MW of rental generators are introduced in 2022 in the following sites suggested by MoEW:

- 83 MW are added in Jib Jannine.
- 83 MW are added in Bint Jbeil.
- 504 MW are added in Deir Ammar.
- 252 MW are added in Zahrani.
- 108 MW are added in Jieh.

The unserved energy in 2020 is expected to amount to around 9 500 GWh (40% of total demand). Should the rental projects proceed, the unserved energy will decrease to around 1 240 GWh in 2022 (6%) and 1620 GWh in 2023 (7%). Under these conditions, the increase in tariffs must be approved systematically after the arrival of temporary production.

### PERMANENT SOLUTIONS

Starting 2024, the permanent solutions will start being commissioned. The permanent generation capacity will start to increase, replacing the rental solutions and building system reserves. While the rental generation capacity will be lost in 2024, three 3x1 tri-fuel CCGT units running in open cycle mode (first phase) will add 561 MW of capacity in their three respective sites. Starting 2025 these units will be fully commissioned in closed cycle, increasing their capacity to 825 MW. The commissioning of the CCGTs in open-cycle mode will be met with the decommissioning of the Zouk and Jieh plants. Finally, an additional 2x1 tri-fuel CCGT will add 374 MW in 2028 (open cycle) and 176 MW in 2030 (transition to closed cycle).



Concerning renewables, solar PV will have a constant expansion rate of 250 MW/yr (maximum allowed by constraints), starting 2023, for this variant of the plan. It reaches a maximum of 2 180 MW in 2030. Wind projects will be added occasionally throughout the 2024 – 2030 interval totaling 1 016 MW in 2030. Run of the River Hydro is fixed in this study, with respect to the “Hydro Master Plan”.

The CSP project to be commissioned in 2025 is already committed by the MoEW. No new CSP capacity was suggested by the optimizer.

Although distributed solar PV is included as a candidate project for the optimizer, the technology’s current high build cost makes it uncompetitive compared to centralized scale projects. Understandably, the optimizer did not add distributed solar PV. Nevertheless, the installation of such projects would prove beneficial for the system as they are close to the consumer.

Currently the system does not have any storage capacity. Starting 2023, system storage is increased to reach 201 MW/213 MWh of BESS by 2030, and 49 MW/196 MWh of Pumped-Hydro Storage (Joun dam upgrade, 2027).

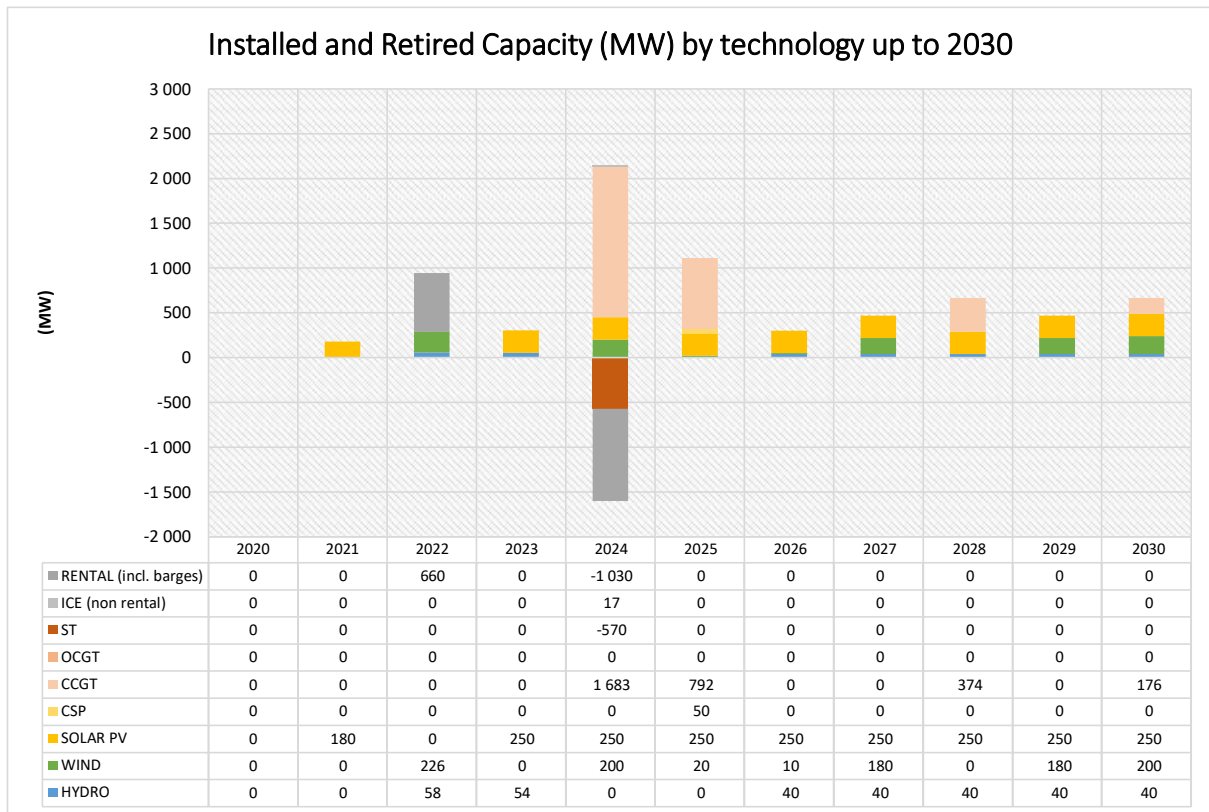
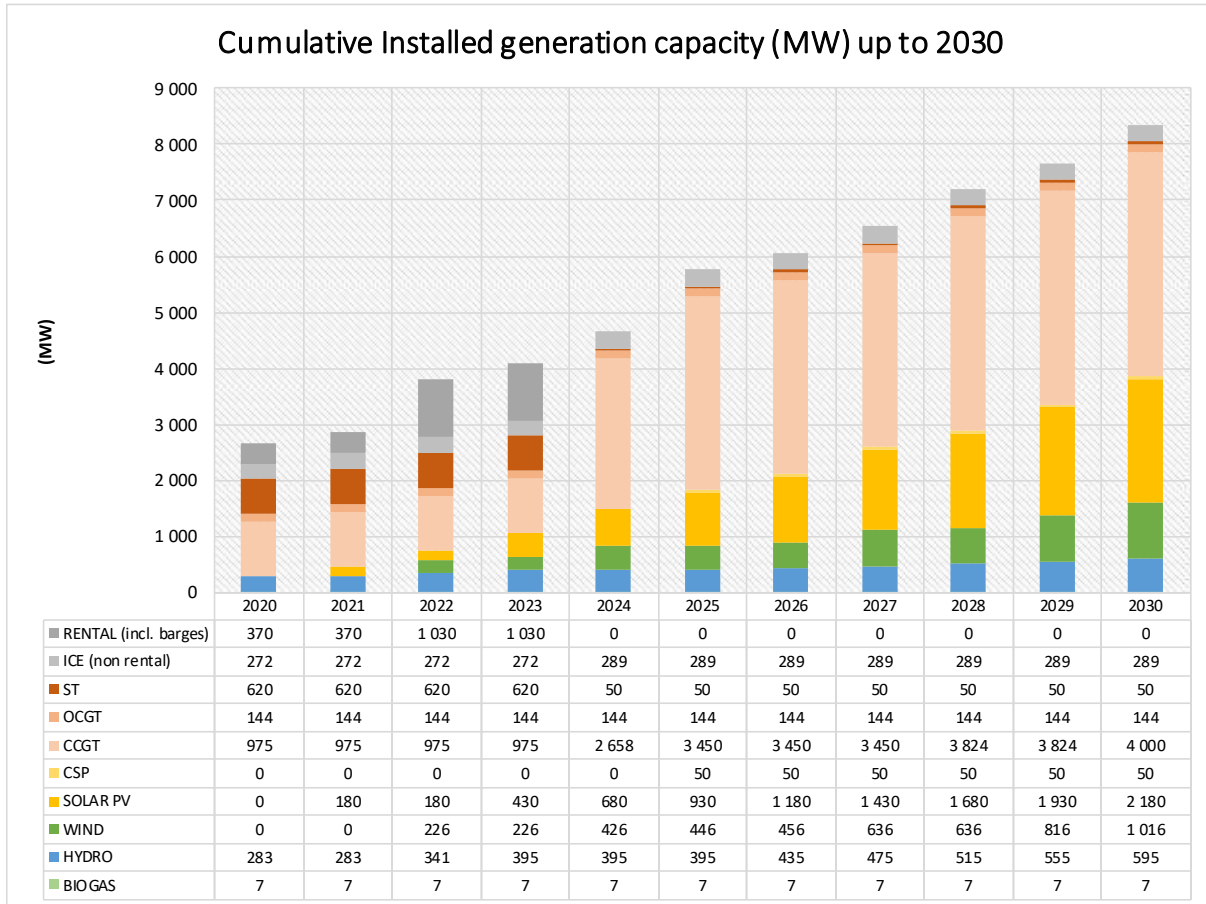


Figure: Base Case Scenario Installed and Retired Capacity



The graph shown below depicts the current generation capacity state and its evolution throughout the horizon of the study. EDL's derated maximum generation capacity is currently at 2 670 MW<sup>1</sup>, distributed between thermal (2 018 MW), hydro (282 MW) and rental barges (370 MW). The optimal generation plan will ramp up the total capacity to 8 331 MW including 4 483 MW of thermal, 595 MW of RoR hydro, 50 MW of CSP, 2 180 MW of solar PV and 1 016 MW of wind.



*Figure 3: Base Case Scenario Cumulative Installed Generation Capacity*

The table below provides the schedule for the installation and commissioning of each generation unit proposed in this plan. Note however that all NG fired power plants depend completely on the availability of Natural Gas in the concerned sites. The above-mentioned NG schedule requires:

- Availability of NG in Deir Ammar by 2023;
- Availability of NG in Zahrani by 2023;
- Availability of NG in Selaata by 2024.

Delays on these timings will result in delays on the overall generation planning.

Note that a one-year delay in Deir Ammar and Zahrani may be absorbed with minor modifications to the planning (i.e. delaying the switch to NG by 1 year).

<sup>1</sup> Note that this value is the sum of the maximum capacity of all generators. It cannot be reached at any one time, because it would imply activating all generation units. Practically, generation is further limited by outages and environmental factors (temperature and humidity).



Location/technologie	Power plant available capacity (MW) Number of FSRU or pipeline	Base Case													
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030			
BINT JBEIL	N ICE FO				83	83									
JIB JANNINE	N ICE FO				83	83									
DEIR AMMAR	E CCGT RUNNING ON GO	490	490	490											
	E CCGT RUNNING ON NG				490	490									
	N RENTAL ICE			504	504										
	N FSRU				1	1	1	1	1	1	1	1	1	1	1
	N CCGT 2x1 - E						561	825	825	825	825	825	825	825	825
	N CCGT 3x1 - E					1,051	1,315	1,315	1,315	1,315	1,689	1,689	1,689	1,689	
	<b>Total</b>	490	490	994	994	561	825	825	825	825	1,689	1,689	1,689	1,689	
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50	50	50	50	50	
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA					1	1	1	1	1	1	1	1	1	
	N CCGT 2x1 - E					561	825	825	825	825	825	825	825	825	
	<b>Total</b>					561	825	825	825	825	825	825	825	825	
ZOUK	E ICE BARGE	185	185												
	E ICE FO	194	194	194	194	194	194	194	194	194	194	194	194		
	E ST	380	380	380	380										
	<b>Total</b>	759	759	574	574	194	194	194	194	194	194	194	194		
ZAHRANI	E CCGT RUNNING ON GO	485	485	485											
	E CCGT RUNNING ON NG				485	485									
	N RENTAL ICE			252	252										
	N FSRU				1	1	1	1	1	1	1	1	1	1	
	N ICE DF NG					17	17	17	17	17	17	17	17	17	
	N CCGT 3x1 - E					561	825	825	825	825	825	825	825		
	<b>Total</b>	485	485	737	737	1,063	1,327	1,327	1,327	1,327	1,327	1,327	1,327		
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74	74	74	74		
JIEH	E ICE BARGE	185	185												
	E ICE FO	78	78	78	78	78	78	78	78	78	78	78	78		
	E ST	190	190	190	190										
	N RENTAL ICE			108	108										
	<b>Total</b>	453	453	376	376	78	78	78	78	78	78	78	78		
SOUR	E OCGT	70	70	70	70	70	70	70	70	70	70	70			
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21	21	21			
	LITANI	199	199	199	199	199	199	199	199	199	199	199			
	NAHR BARED	17	17	17	17	17	17	17	17	17	17	17			
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32	32	32			
	SAFA	13	13	13	13	13	13	13	13	13	13	13			
	DARAYA, CHAMRA, YAMOUNEH & BLAT			58	58	58	58	58	58	58	58	58			
	JANNEH			54	54	54	54	54	54	54	54	54			
	REMAP BALANCE						40	80	120	160	200				
	<b>Total</b>	283	283	341	395	395	395	435	475	515	555	595			
SOLAR PV		180	180	430	680	930	1,180	1,430	1,680	1,930	2,180				
CSP	N_CSP_STORAGE_7.5H_CF_27_MAX_1187						50	50	50	50	50				
WIND			226	226	426	446	456	636	636	816	1,016				
BIOGAS	E_BIOGAS_NAAMEH	7	7	7	7	7	7	7	7	7	7				
Storage	BESS (MW/MWh)				201/213	201/213	201/213	201/213	201/213	201/213	201/213	201/213			
	N_JOUN_PHS_UPGRADE_49.3MW_4H							49	49	49	49				
	<b>Total (MW/MWh)</b>				201/213	201/213	201/213	250/410	250/410	250/410	250/410				

Table 4: Base Case - Installed Capacity Schedule

	Base Case										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
<b>Total Installed generation capacity by technology (MW)</b>											
RENTAL (incl. barges)	370	370	1,030	1,030							
ICE (non rental)	272	272	272	272	289	289	289	289	289	289	289
ST	620	620	620	620	50	50	50	50	50	50	50
OCGT	144	144	144	144	144	144	144	144	144	144	144
CCGT	975	975	975	975	2,658	3,450	3,450	3,450	3,824	3,824	4,000
HYDRO	283	283	341	395	395	395	435	475	515	555	595
SOLAR PV		180	180	430	680	930	1,180	1,430	1,680	1,930	2,180
DISTRIBUTED SOLAR PV											
CSP						50	50	50	50	50	50
WIND			226	226	426	446	456	636	636	816	1,016
BIOGAS	7	7	7	7	7	7	7	7	7	7	7
	<b>Total (MW)</b>	2,671	2,851	3,795	4,099	4,649	5,761	6,061	6,531	7,195	7,665
<b>Total storage capacity by technology (MW)</b>											
PHS (MW/MWh)							49/197	49/197	49/197	49/197	49/197
BESS (MW/MWh)					201/213	201/213	201/213	201/213	201/213	201/213	201/213
	<b>Total (MW/MWh)</b>				201/213	201/213	201/213	250/410	250/410	250/410	250/410

Table 5: Base Case - Cumulative Installed Capacity by generation type



#### 4.1.2. CAPACITY RESERVE MARGIN

Capacity reserve margin is the margin the system relies upon to cater for an N-1 event during peak demand. Only the firm capacity of a generator may be factored in the capacity reserve margin calculation. This includes all dispatchable generation plants, CSP and hydro pumped storage, as well as 10% RoR hydro and 96% BESS (> 4 hr). RE contribution heavily depends on the seasons. The yearly average is 9% for solar PV and 7% for wind. An acceptable level of capacity reserve margin would be around 10% of peak demand.

The graph shown below depicts the available capacity during peak demand, and its evolution throughout the horizon of the study. The 2020 firm capacity of EDL's thermal (including barges) generation fleet amounts to 2 018 MW. The optimal generation plan will ramp up the thermal firm capacity to 4 222 MW. Additionally, hydro firm capacity contribution will increase to 59 MW, solar will account for 196 MW, CSP for 50 MW, wind for 71 MW, and storage for 53 MW.

The system will start building up CRM starting 2024. By 2025 it will reach 6%. Throughout the rest of the study's horizon, CRM will continue to increase as new capacity is introduced into the mix (including solar, wind and storage).

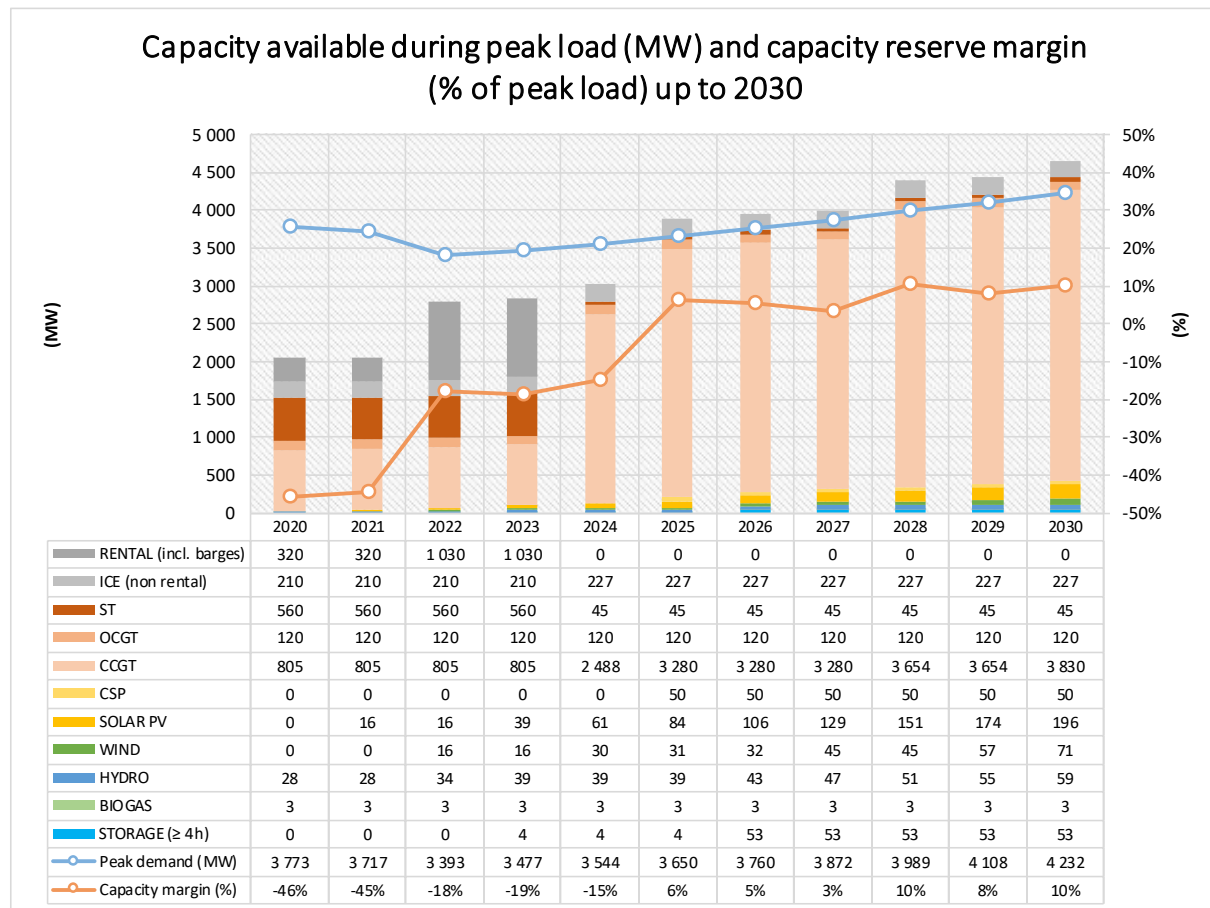


Figure 4: Base Case - Capacity available during peak load and Capacity Reserve Margin





#### 4.1.3. GENERATION MIX

As is visible in the graph below, Lebanon’s generation mix is mainly reliant on Open/Closed cycle gas turbines, along with steam turbines, ICEs and rental solutions. As the system evolves per the optimal generation plan, the existing CCGTs will switch to NG and see their share in the mix increase. While ICEs and ST recede, RE technologies will ramp up. Rental solutions in the graph reflect the strategy discussed in §4.1.1 (Temporary Solutions). By 2024, the mix is predominantly CCGT based with a decent share of RE. Solar PV will continuously increase throughout the horizon of the study, thus ensuring demand satisfaction. Wind and hydro follow the same trend, with a slower pace. Under this plan, RE penetration will increase from 4% in 2020 to 32% in 2030.

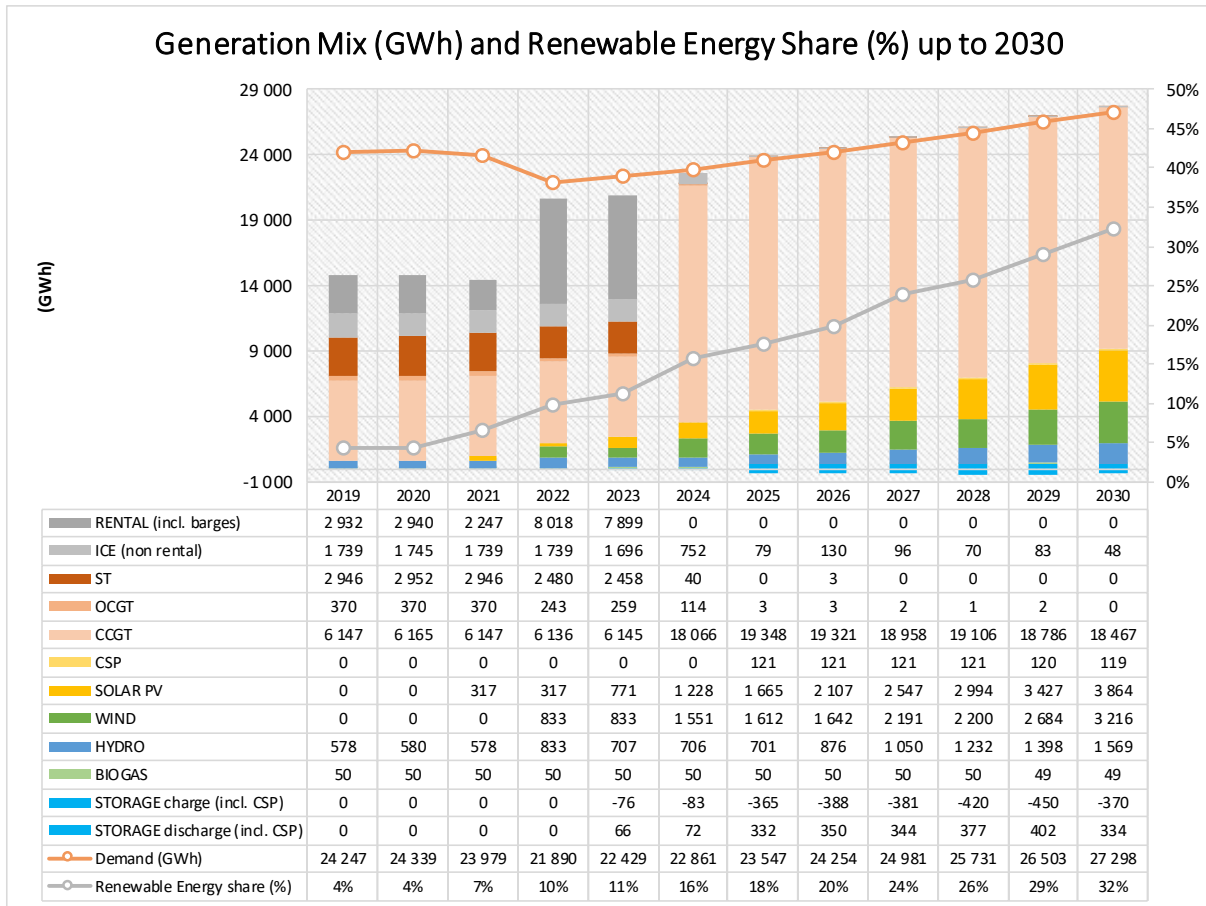


Figure 5: Base Case - Generation Mix



#### 4.1.4. CAPACITY FACTOR

The average annual capacity factor is the ratio of actual energy generated by a unit over its maximum capacity during a whole year (8760 hours).

$$CF (\%) = \frac{\text{Generated Energy (GWh)}}{\text{Generation Capacity (MW)} * 8760 h}$$

As depicted in the graph below, the average capacity factor for solar is around 20%. Wind has a factor of 40%. As for hydro, these projects will have their capacity factor decreased due to the Conveyor 800 Litani project. It will increase afterwards with the commissioning of new hydro projects.

Lately the OCGTs have had a low capacity factor of 30%, due to their low efficiency and high variable costs. Their capacity factor will go down to 0% in 2025, and they will start serving as extreme peaker plants and capacity margin reserves, always running on LFO. Similar is the case of the ICEs which will cater for peak production and capacity margin. As for CCGTs, the new units will have a high capacity factor as base load generators (CF > 75%), while the older ones will serve as peakers, and help build Capacity Reserve Margin (CF < 15%).

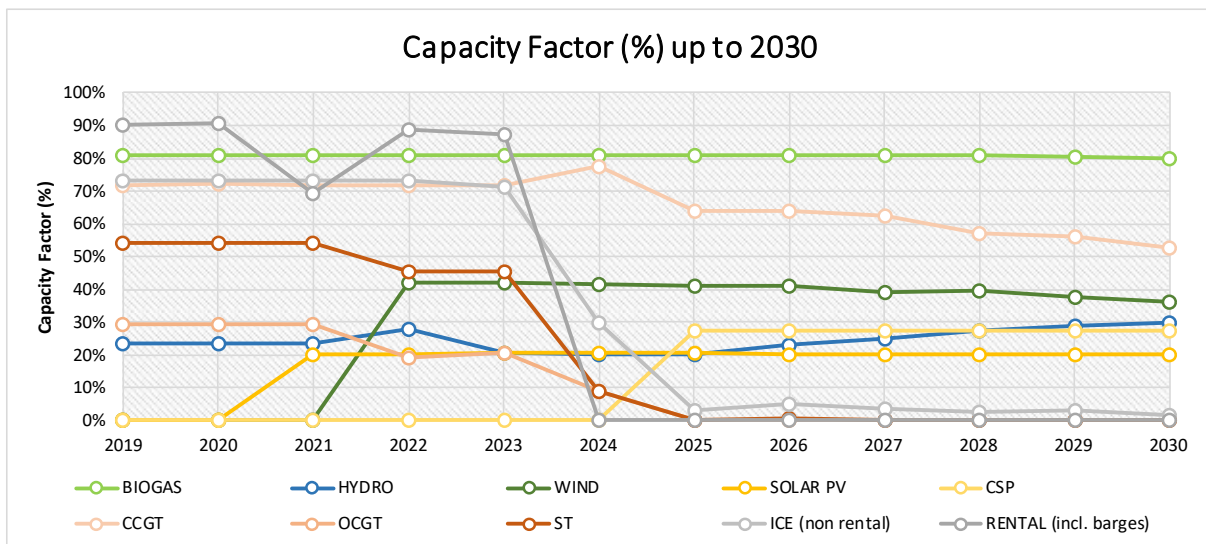


Figure 6: Base Case - Average Capacity factor projection per technology

#### 4.1.5. UNSERVED ENERGY

The Loss of Load Probability (LOLP) is the probability that the demand will exceed the generation capacity of the system. This value is computed on a yearly basis:

$$LOLP (\%) = \frac{\text{Unservd Energy Hours (h)}}{\text{Total Hours in a Year (h)}}$$

“Unservd Energy Hours” is the total number of hours in which there was any amount of unserved energy.

The current generation capacity is not enough to meet demand. This puts the system in permanent load shedding. In other words, at no time throughout the whole year does the generation fulfill the demand. This results in a LOLP of 100%, as seen for the years 2020 and 2021 in the graph below.

In 2022-2023, should the rental solutions be installed, the LOLP will drop down to ~53%, resulting in zero-mismatch between generation and demand for ~4 150 hours per year. In 2025, with the full commissioning of the 3 CCGTs, the loss of load becomes negligible. This means that the system would have practically reached a 24/24h supply, in absence of any contingencies.

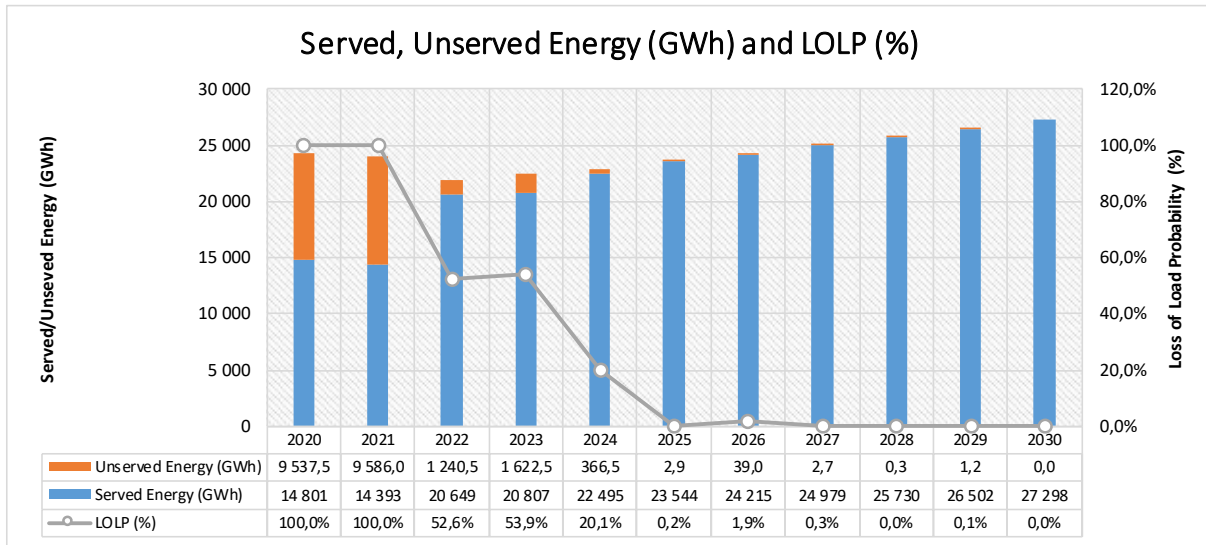


Figure 7: Base Case - Served, Unserved energy, and LOLP projections

The following graph shows the Cumulative Distribution Function (CDF) of the Supply/Demand fulfilment. To read the graph one must choose a number of fulfilled Supply/Demand hours (say 12/24) and find the corresponding number of days (125 days for 2022 for example). This means that in 2022 for instance, system supply will fully match the demand for **at least** 12 hours a day, for 125 days of the year.

By construction, the graph considers as an unserved energy hour an hour with any level of unserved energy (supply/demand mismatch), however small it may be.

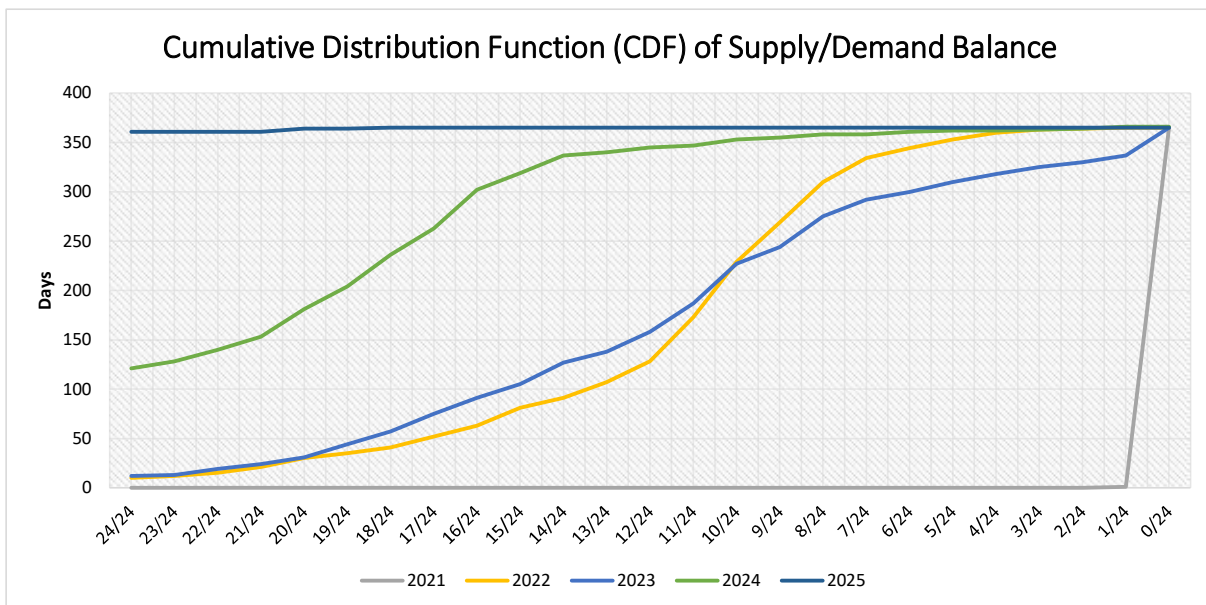


Table 6: Base Case - Cumulative Distribution Function of Supply/Demand Balance

In Lebanon, load shedding is executed on a round robin basis. Consumers are divided into 4 groups, which rotates shedding ranking (priority). So, a consumer will actually experience only around ¼ of the system's unserved energy hours. The graph below reflects this, and shows the perceived supply hours by any given client.

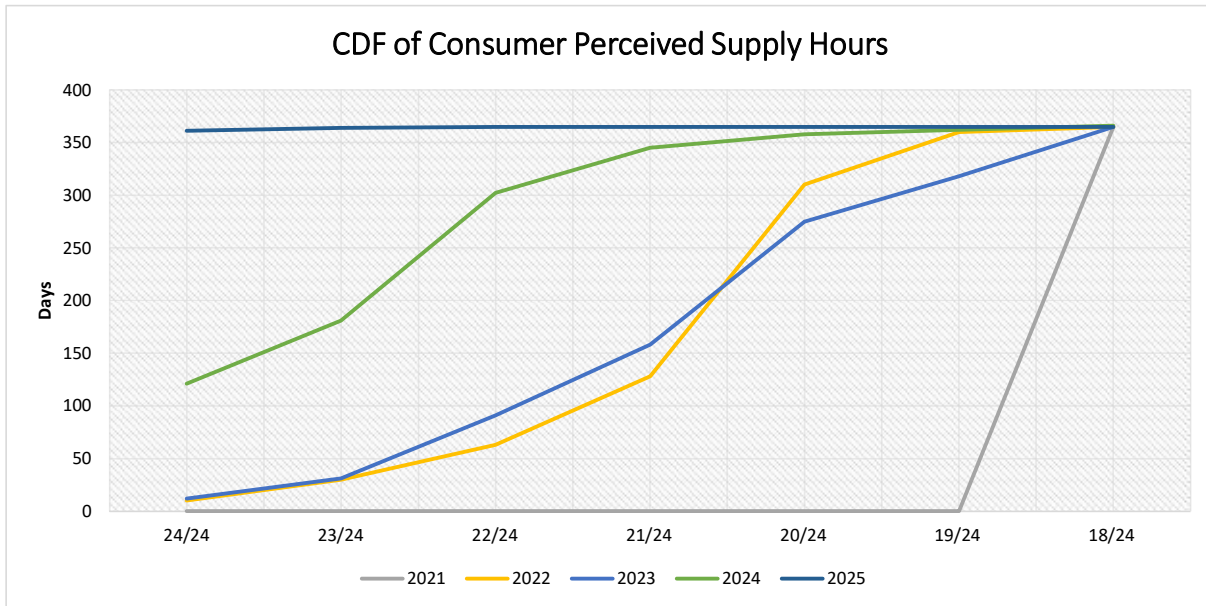


Table 7: Base Case - Cumulative Distribution Function of consumer perceived supply hours

For instance, our former example, presented 125 days with at most 12 hours of unserved energy. This translates to a perceived unserved energy of at most 3 hours for the corresponding 125 days, by the clients. This means that theoretically, without taking non-technical factors into account, EDL will be able to increase its tariffs by 2022.

#### 4.1.6.EMISSIONS AND FUEL CONSUMPTION

The following graph illustrates the variation of CO<sub>2</sub> emission generated by fuel consumption throughout the horizon of this study. In 2022, the fuel emissions rise with the increase of the total served energy (HFO rental solutions). From 2023 onwards, the emissions will decline as the old inefficient HFO power plants are replaced (decommissioning of Zouk and Jieh) with newer efficient NG technologies (Deir Ammar, Selaata and Zahrani), and the existing Deir Ammar and Zahrani CCGTs switch to NG. The CO<sub>2</sub> emission intensity continues to decline slightly thanks to the increase of RE penetration in the mix, while the CO<sub>2</sub> emission remains constant despite the increase in demand.

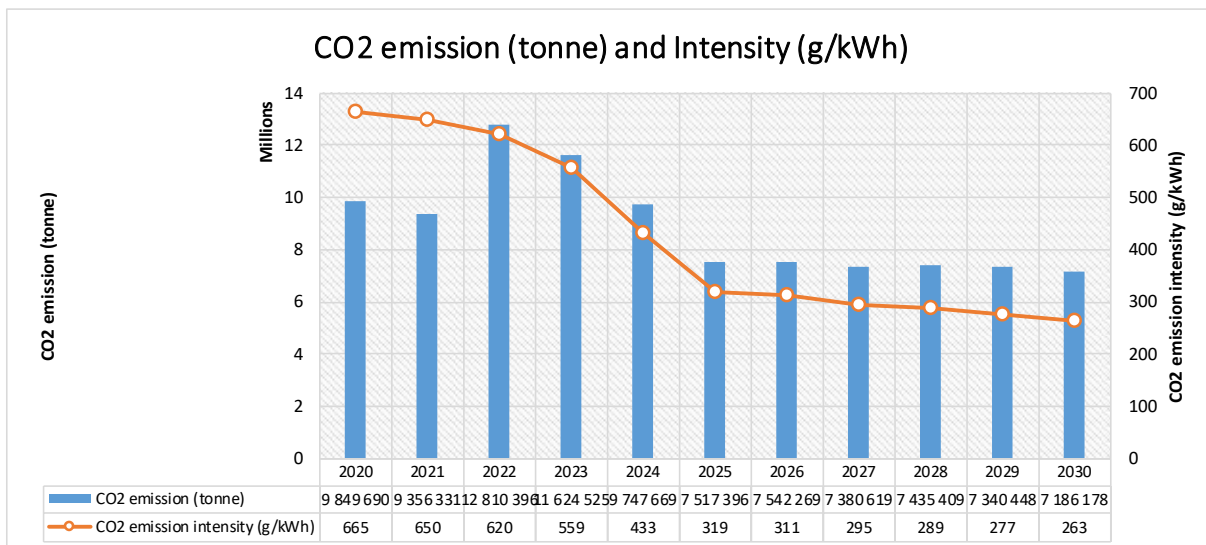


Figure 8: Base Case - CO<sub>2</sub> emission and intensity projection



Figure 9 details the fuel consumption (offtake in TJ) and the average heat rate for each fuel type, in the 2020 – 2030 interval. Note that while pre-2024 the system’s offtake was dominated by Fuel Oil, once the new NG CCGTs are introduced and the old CCGTs are switched to NG, Natural Gas displaces Fuel Oil as the main fuel type for the system.

Fuel oil efficiency increases around 2022 – 2024 as the inefficient Zouk and Jieh units are decommissioned.

As the CCGTs of Deir Ammar and Zahrani switch from Gas Oil to Natural Gas in 2022, only the Sour and Baalback units will remain on Gas Oil, thus increasing its overall heat rate.

Meanwhile, with the aforementioned conversion, the NG heat rate comes into play in 2023. It increases in 2024 due to the new CCGTs being commissioned in Open Cycle. Then the heat rate decreases starting 2025, as these new CCGTs are fully commissioned. Figure 10 isolates the NG off-take in the 1 000 TJ unit and the BCM (Billions of cubic meters) unit.

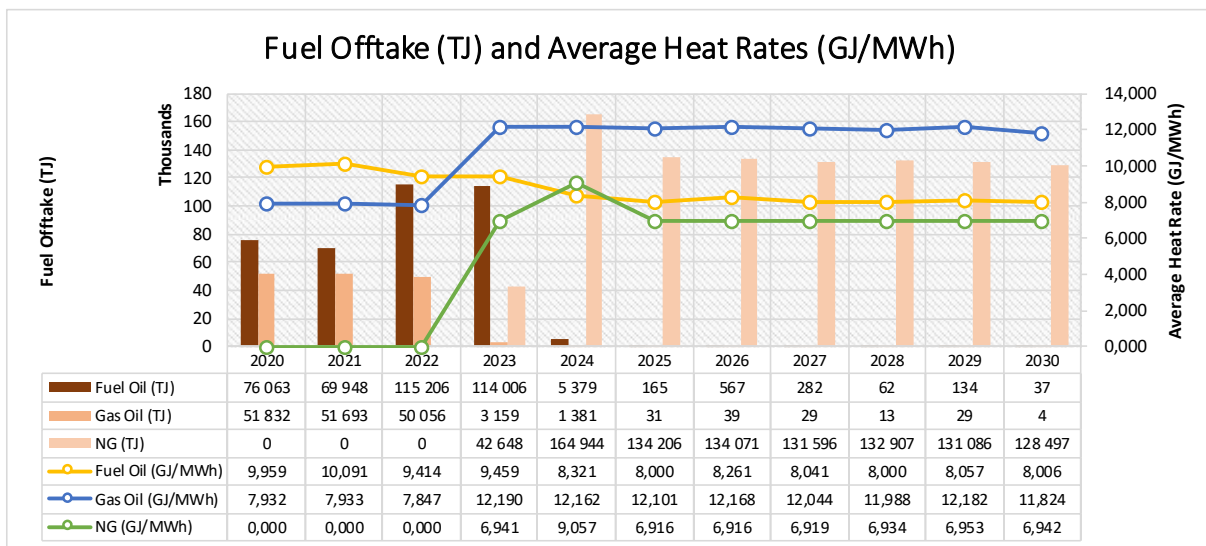


Figure 9: Base Case - Fuel Offtake and Average Heat Rate per fuel type

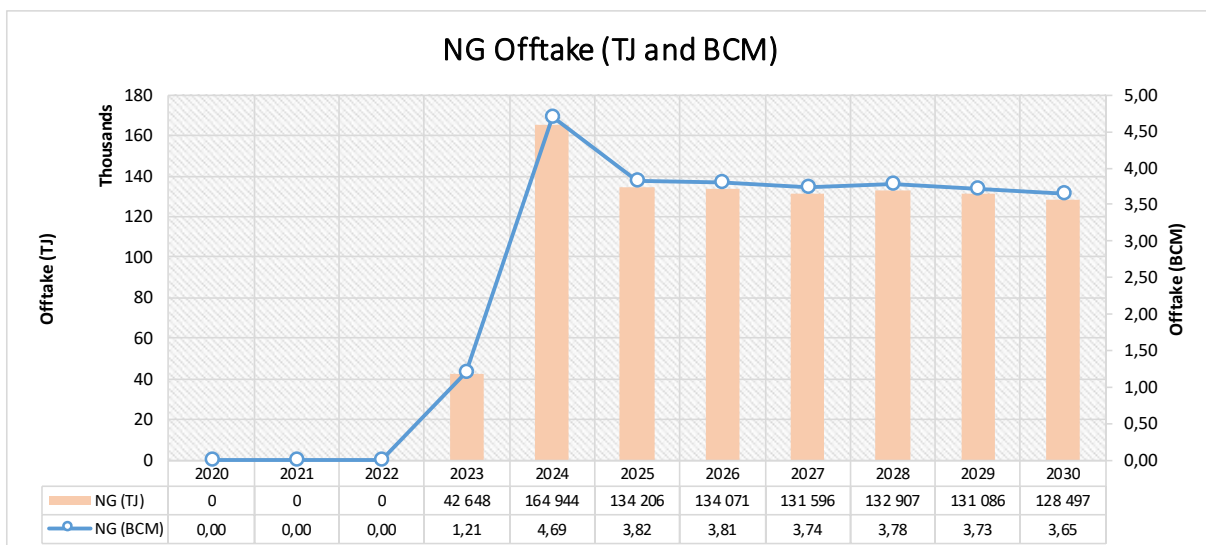


Figure 10: Base Case - NG Offtake



#### 4.1.7. COST BREAKDOWN & BUDGET ESTIMATES

The graph below shows a cost breakdown for the Least Cost Generation Plan. For each year the total costs are broken down into the following components:

- FO&M cost: Fixed Operation and Maintenance costs;
- Annualized Build Cost: Generation CAPEX annuities;
- Emissions Cost: The Shadow Price of Carbon (SPC);
- VO&M cost: Variable Operation and Maintenance costs including transport and storage;
- Fuel Cost: The total fuel cost;
- NG Infrastructure Cost: Capacity charge for FSRUs and pipelines;
- Retirement cost: The cost associated with retiring generation units.

Additionally, the graph depicts the Generation Cost and the Total System Cost:

$$\text{Generation Cost (\$/MWh)} = \frac{\text{Fuel Cost} + \text{VO\&M Cost} + \text{Emissions Cost (\$)}}{\text{Served Energy (GWh)}}$$

$$\text{Total System Cost (\$/MWh)} = \frac{\text{Fuel Cost} + \text{VO\&M Cost} + \text{Emissions Cost} + \text{Annualized Build Cost} + \text{FO\&M Cost} + \text{Retirement Cost (\$)}}{\text{Served Energy (GWh)}}$$

N.B: For the years 2019 and 2020 the VO&M includes the FO&M. After 2020 the two costs are separated.

The total system cost decreases between 2019 and 2020 (from ~130 \$/MWh to ~88 \$/MWh) with the Brent price, due to the Covid19 crisis.

The Base Case least cost generation plan proposed in this study orients the system towards Natural Gas and Renewables as its main generation capacity contributors. This increases the overall efficiency of the system, thus dropping the Total System Cost over time to 74.26 \$/MWh by 2030.

While the main cost centers pre-2023 were generation costs, post-2023 we start seeing an increase in annualized build costs as the proposed projects are successively commissioned.

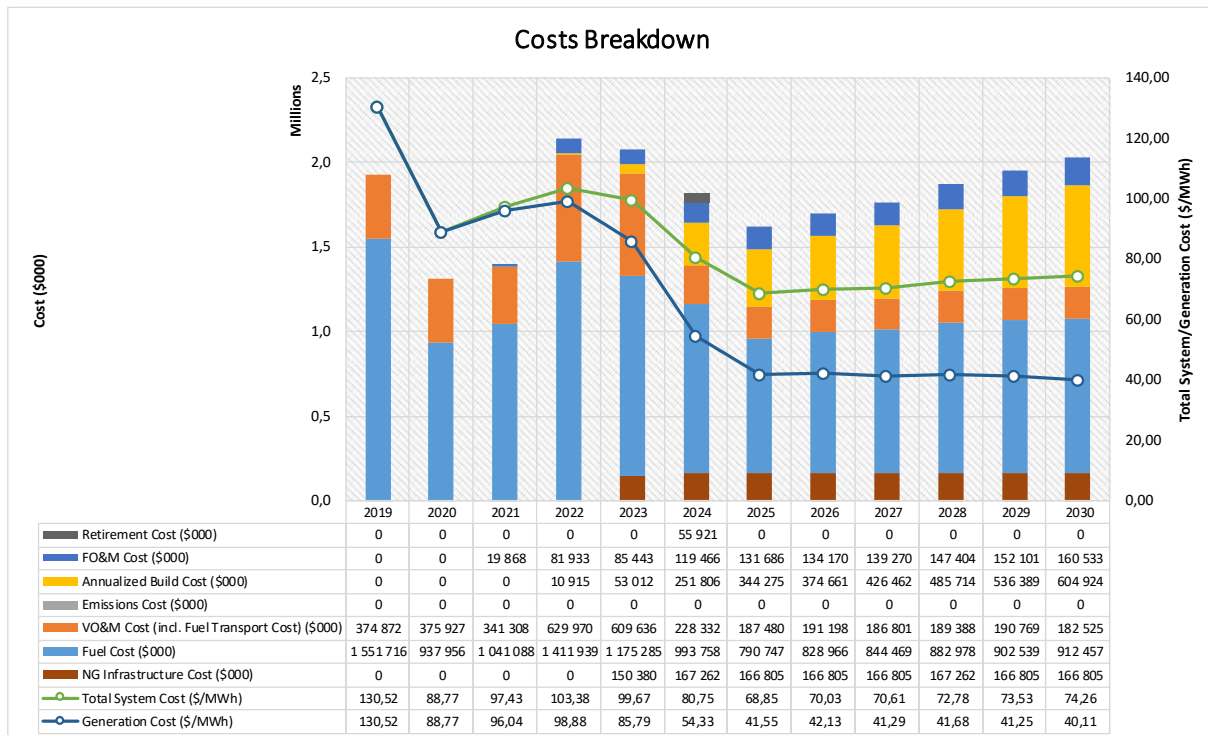


Figure 11: Base Case - Costs Breakdown

	Base Case											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
<b>Costs Breakdown (real 2019 \$000)</b>												
NG Infrastructure Cost (\$000)					150 380	167 262	166 805	166 805	166 805	167 262	166 805	166 805
Fuel Cost (\$000)		937 956	1 041 088	1 411 939	1 175 285	993 758	790 747	828 966	844 469	882 978	902 539	912 457
VO&M Cost (incl. Fuel Transport Cost) (\$000)		375 927	341 308	629 970	609 636	228 332	187 480	191 198	186 801	189 388	190 769	182 525
Emissions Cost (\$000)												
Annualized Build Cost (\$000)				10 915	53 012	251 806	344 275	374 661	426 462	485 714	536 389	604 924
FO&M Cost (\$000)			19 868	81 933	85 443	119 466	131 686	134 170	139 270	147 404	152 101	160 533
Retirement Cost (\$000)					0	55 921						
<b>Total Cost (incl. Retirement Cost) (\$000)</b>	<b>1 313 883</b>	<b>1 402 263</b>	<b>2 134 757</b>	<b>2 073 756</b>	<b>1 816 545</b>	<b>1 620 993</b>	<b>1 695 801</b>	<b>1 763 807</b>	<b>1 872 746</b>	<b>1 948 603</b>	<b>2 027 244</b>	
<b>Total Cost (excl. Retirement Cost) (\$000)</b>	<b>1 313 883</b>	<b>1 402 263</b>	<b>2 134 757</b>	<b>2 073 756</b>	<b>1 760 625</b>	<b>1 620 993</b>	<b>1 695 801</b>	<b>1 763 807</b>	<b>1 872 746</b>	<b>1 948 603</b>	<b>2 027 244</b>	
<b>Indicative Costs excl. Emissions Cost (real 2019 \$)</b>												
Total System Cost (\$/MWh)	88.77	97.43	103.38	99.67	80.75	68.85	70.03	70.61	72.78	73.53	74.26	
Generation Cost (\$/MWh)	88.77	96.04	98.88	85.79	54.33	41.55	42.13	41.29	41.68	41.25	40.11	
<b>Indicative Costs incl. Emissions Cost with high WB SPC (real 2019 \$)</b>												
SPC (\$/tonne)	82	84	86	88	89	91	93	96	98	100	102	
Emissions Cost (\$000)	805 792	784 566	1 100 404	1 022 313	867 222	684 176	701 865	709 465	729 939	735 629	734 866	
Total System Cost (\$/MWh)	143.21	151.93	156.67	148.80	119.31	97.91	99.02	99.02	101.15	101.29	101.18	
Generation Cost (\$/MWh)	143.21	150.55	152.17	134.92	92.88	70.61	71.12	69.69	70.05	69.01	67.03	
<b>Indicative Costs incl. Emissions Cost with EIB SPC (real 2019 \$)</b>												
SPC (\$/tonne)	93	112	132	152	171	191	211	230	250	270	289	
Emissions Cost (\$000)	912 156	1 050 592	1 690 535	1 762 801	1 670 010	1 435 847	1 589 023	1 700 210	1 859 154	1 979 863	2 079 671	
Total System Cost (\$/MWh)	150.39	170.42	185.25	184.39	154.99	129.83	135.65	138.68	145.04	148.24	150.45	
Generation Cost (\$/MWh)	150.39	169.04	180.75	170.51	128.57	102.53	107.75	109.35	113.93	115.96	116.30	

Table 8: Base Case - Costs Breakdown (indicative costs including SPC)



The table below provides a budget estimates for each of the suggested projects in the Least Cost Generation Plan Base Case scenario:

Base Case						
Site	Investment	Capacity (MW)	Date *	Cost	Budget (2019 \$1M)	Comments
Deir Ammar	Addition of a FSRU		2023	206 000 \$/day	752	FSRU Capacity Charge over 10 years
	Switch the existing CCGT to NG		2023			
	Tri-fuel CCGT 3x1 in open cycle	561	2024	800 \$/kW	660	Build Cost
	Full commission Tri-fuel CCGT 3x1	+264	2025			
	Tri-fuel CCGT 2x1 in open cycle	374	2028	807 \$/kW	444	Build Cost
Full commission Tri-fuel CCGT 2x1	+176	2030				
Selaata	Pipeline from Deir Ammar to Selaata		2024	45 000 \$/day	165	Pipeline Capacity Charge over 10 years
	Tri-fuel CCGT 3x1 in open cycle	561	2024	800 \$/kW	660	Build Cost
	Full commission Tri-fuel CCGT 3x1	+264	2025			
Zouk	Retirement of the old Steam Turbines		2024	59 \$/kW	36	Retirement Cost
Zahrani	Addition of a FSRU		2023	206 000 \$/day	752	FSRU Capacity Charge over 10 years
	Switch the existing CCGT to NG		2023			
	Tri-fuel CCGT 3x1 in open cycle	561	2024	800 \$/kW	660	Build Cost
	Full commission Tri-fuel CCGT 3x1	+264	2025			
Internal Combustion Engine (Dual Fuel)	16.6	2024	883 \$/kW	15	Build Cost	
Jieh	Retirement of the old Steam Turbines		2024	59 \$/kW	20	Retirement Cost
Solar PV	+250 MW per year from 2023 to 2030	2 000	2023 till 2030	Average of 652.5 \$/kW from 2023 to 2030	164/yr	Average Build Cost per year
Wind	+200 MW in 2024 +20 MW in 2025 +10 MW in 2026 +180 MW in 2027 +180 MW in 2029 +200 MW in 2030	790	2024 till 2030	Average of 1 200 \$/kW from 2024 to 2030	240 M\$ in 2024 24 M\$ in 2025 12 M\$ in 2026 216 M\$ in 2027 216 M\$ in 2029 240 M\$ in 2030	Average Build Cost per year
Joun Pumped Hydro Storage	Upgrade to PHS	+49 MW/4h	2026	Estimate for building lower reservoir 420 \$/kW	21	Lower reservoir Build Cost
Battery Energy Storage System		+201 MW/213 MWh	2023 till 2030	453 \$/kW 1h 1 267 \$/kW 4h	95	Build Cost

\* Dates reference beginning of year

Table 9: Base Case - Budget Estimates





#### 4.1.8. SPINNING RESERVE

Seeing as the system is currently in deep capacity shortage, it is unreasonable to expect it to have any spinning reserves. As of 2025, the system becomes self-sufficient, and begins building capacity margin and spinning reserve. With the operation of the 3 new CCGTs in closed cycle mode, spinning reserve is added in bulk in 2025 and becomes sufficient immediately. A fundamental role in spinning reserve is played by storage units as well. In fact, they are instrumental in allowing a higher penetration of intermittent energy sources (PV and wind) while preserving system reliability. This is mainly because the technology is highly responsive, fast-ramping and does not need to burn fuel on stand-by.

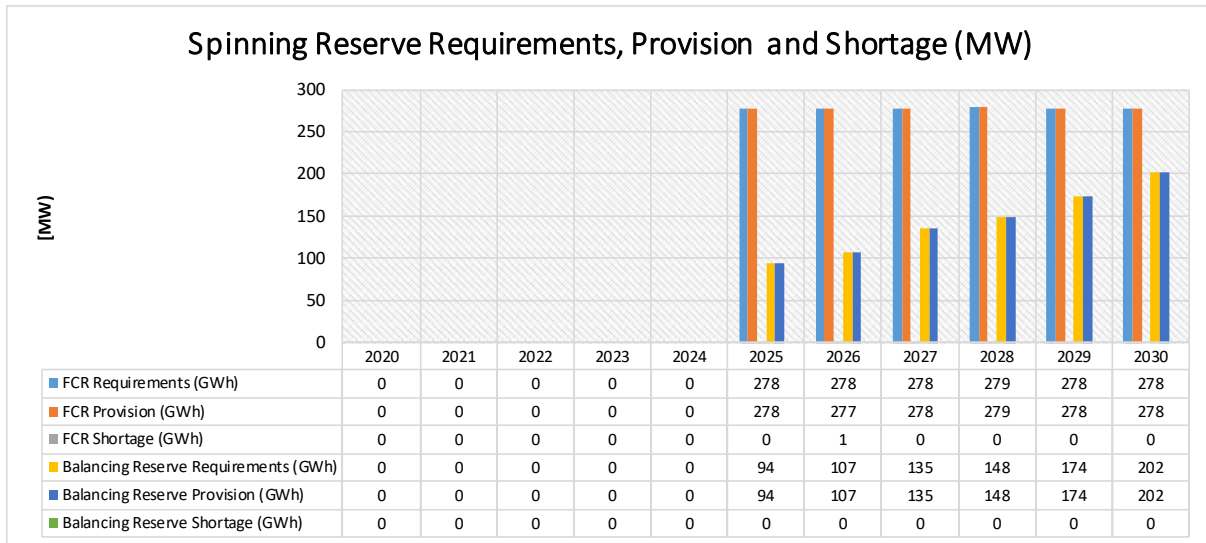


Figure 12: Base Case - Spinning Reserve Requirements, Provision and Shortage



#### 4.1.9. MAINTENANCE SCHEDULING

Well scheduled maintenance is crucial for the operation of the system. The optimization approach ensures enough capacity margin to allow planned outages without any load shedding. Nevertheless, maintenance jobs should be scheduled when the system has the highest capacity margin. As such, the following graph depicts the available capacity reserve throughout the year 2030, thus outlining the optimal times to schedule maintenance. Since planned outage duration is usually measured in weeks, a 1-week moving minimum is applied to the data. In light of the above, it would be convenient to take advantage of the low system load between March and June to perform significant maintenance works with no impact.

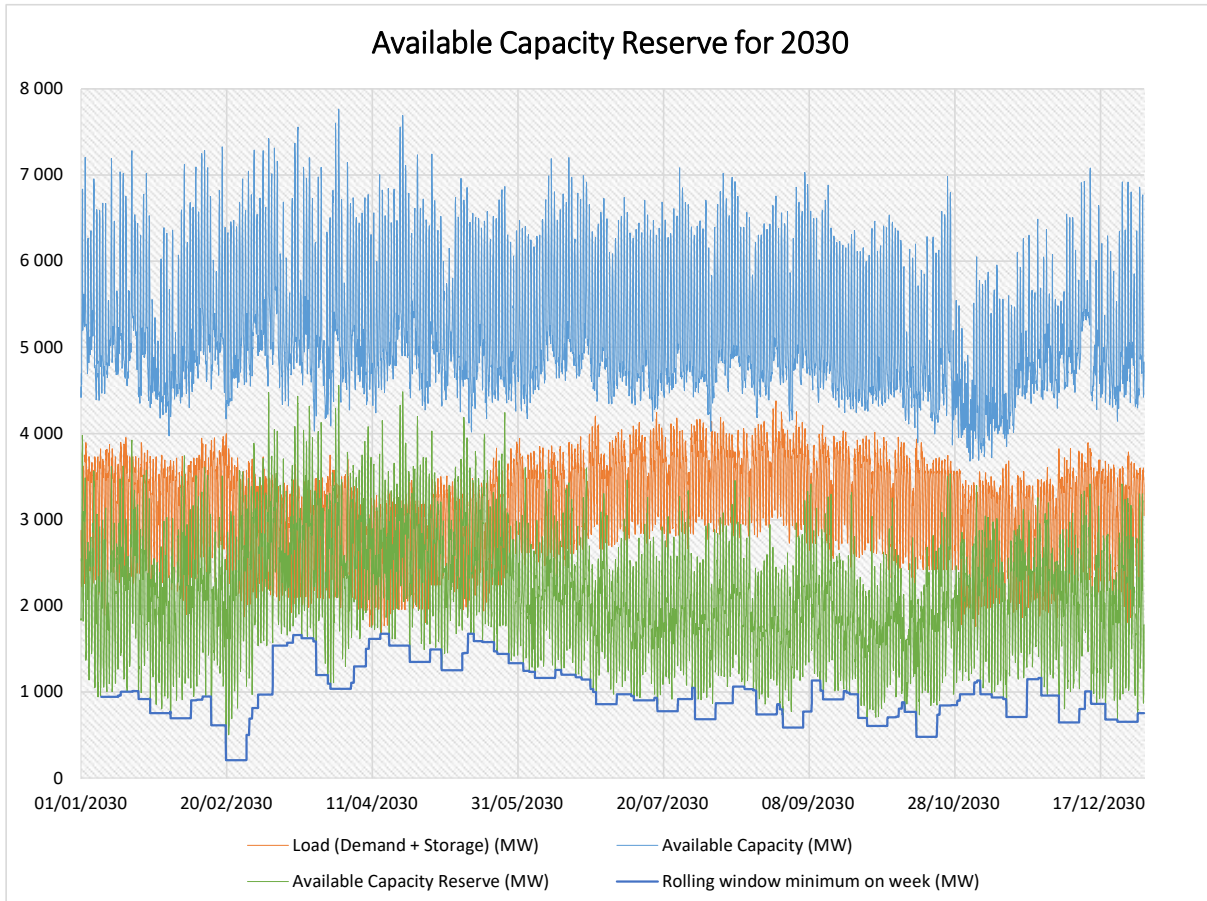


Figure 13: Base Case - Available Capacity Reserve for 2030



#### 4.1.10. OPERABILITY & RENEWABLE PENETRATION

The graph below shows the optimal Short Term (ST) dispatch for the year 2030, on an hourly basis. Note that the new CCGTs provide the base load, while Solar PV and wind generation is absorbed by the system without curtailment (< 1%). Meanwhile CSP stores energy around noon, to be used later on during the evening and the night. Storage units are used to shift some energy from low demand high solar output periods to peak. They are also used as reserve to regulate the intermittency of the variable renewable output. EDL’s existing CCGTs (Deir Ammar and Zahrani) are used to respond to peak load as well.

RoR Hydro generators are seasonal, and help with the base load whenever available.

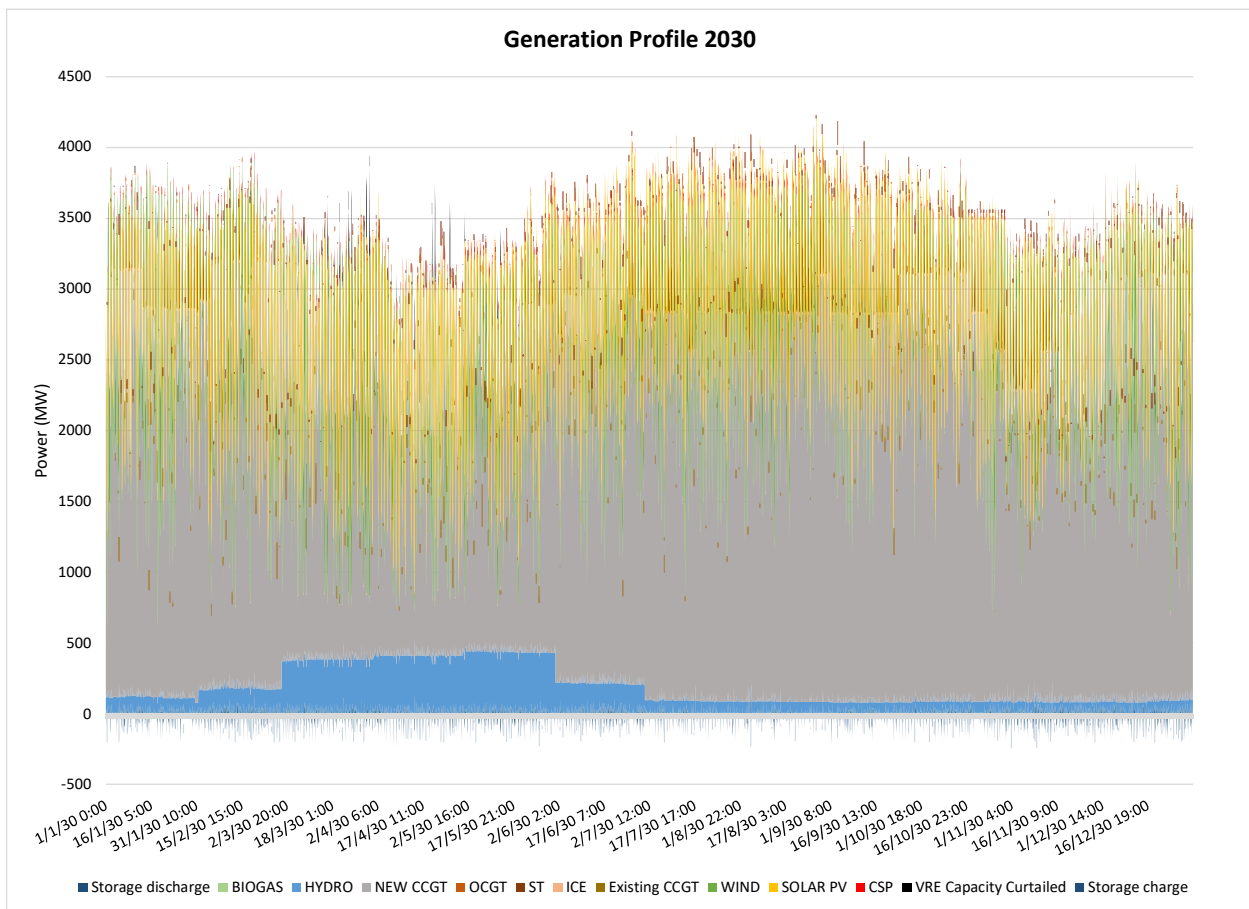


Figure 14: Base Case - Generation Profile 2030



### PEAK DEMAND DISPATCH 2030

The following figure shows the hourly dispatch of the generation during the annual peak demand. The new CCGTs remain the base load power plants throughout the day, while RoR Hydro contribution is minimal. The existing CCGTs are activated with the loss of solar PV, so as to respond to the high demand. During noon hours, the fuel fired power plants' setpoint is reduced in order to give way to wind and solar PV.

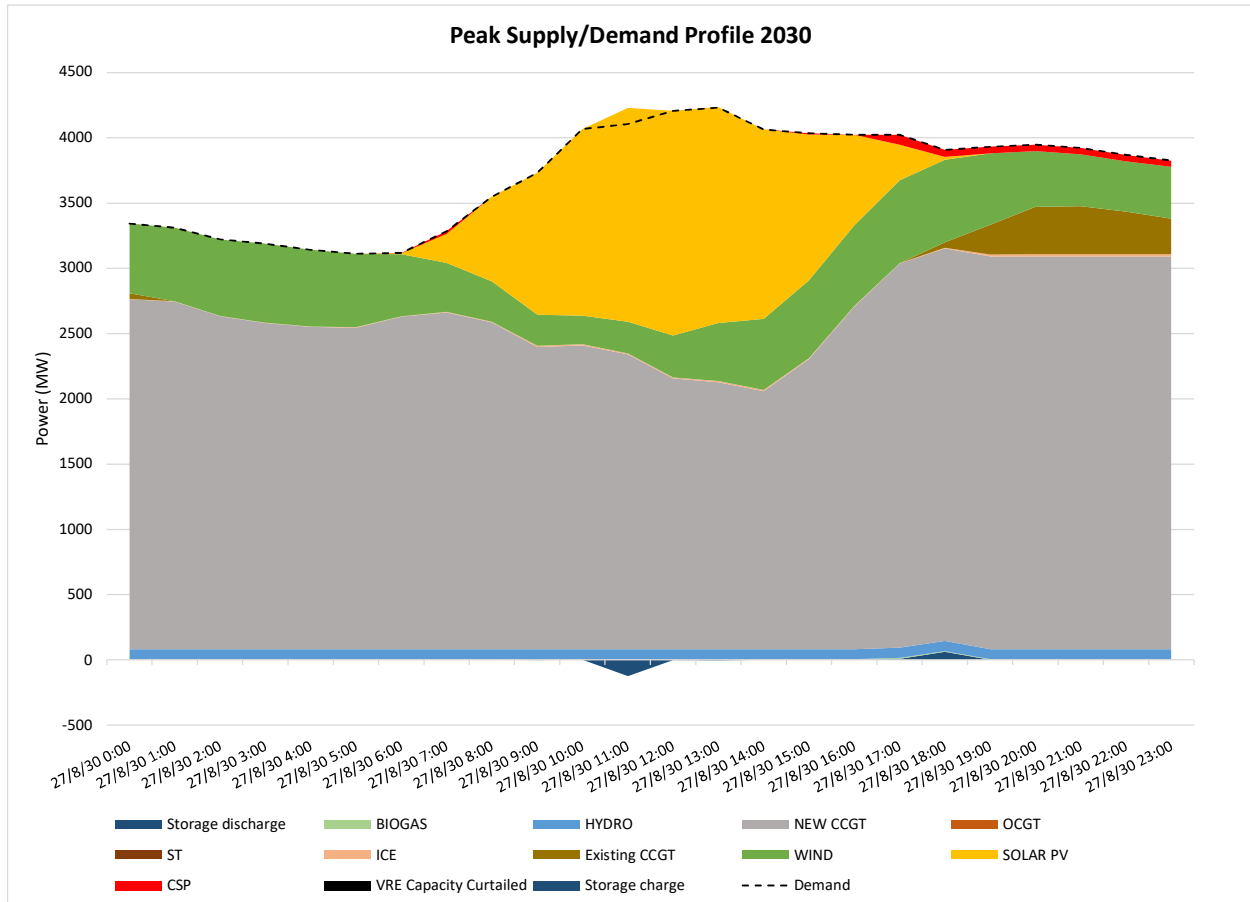


Figure 15: Base Case - Peak Demand Dispatch 2030



### OFF-PEAK DEMAND DISPATCH 2030

During off-peak days, the same analysis remains applicable, with the particularity that Variable Renewable Energy is curtailed during high solar production periods. In order to guarantee enough system inertia for system stability, thermal units are run at minimum technical level during sunny hours. However, the annual VRE curtailment represents less than 1% (0.1% for solar PV and 0.5% for wind) of the available energy and is not a reason for concern given the conservative approach used to determine system inertia requirements.

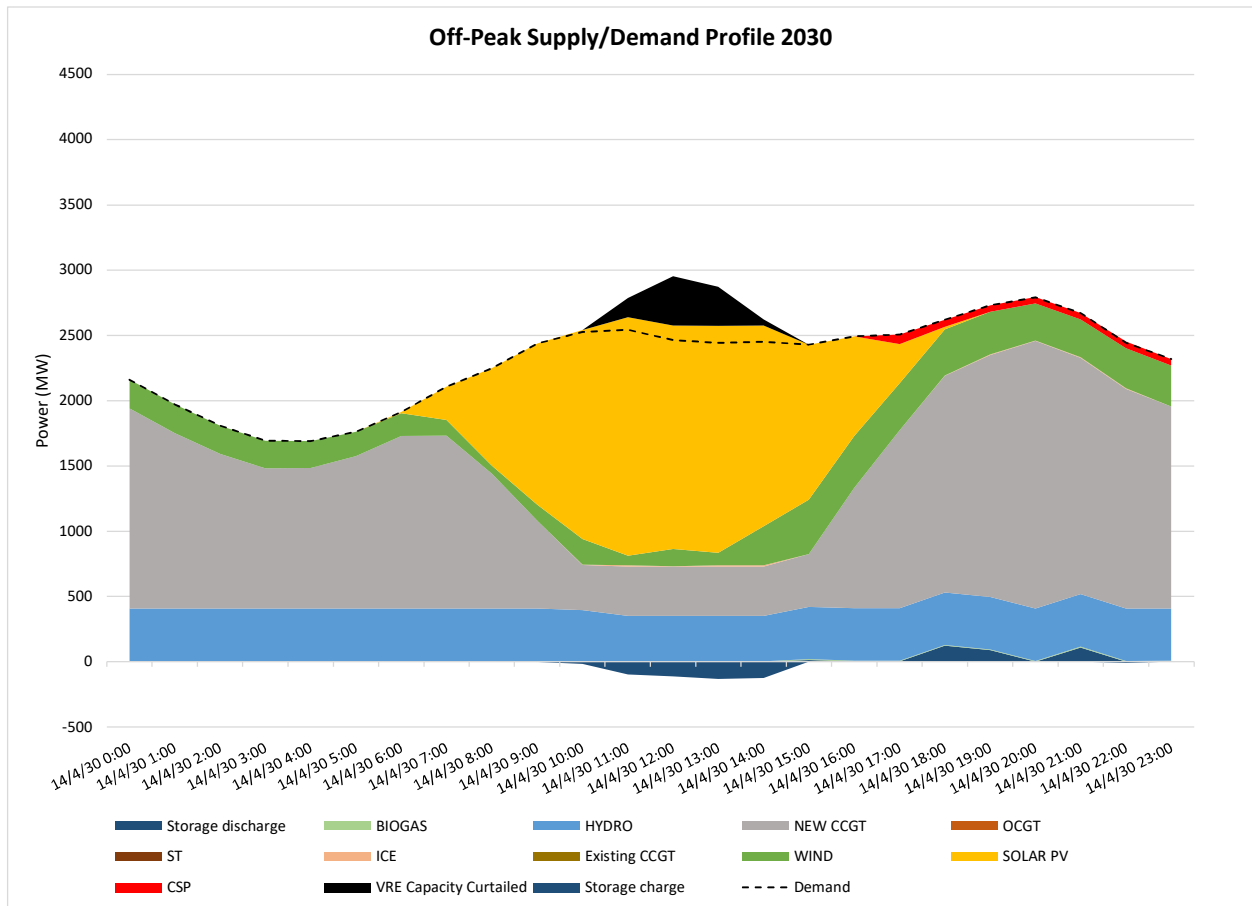


Figure 16: Base Case - Off-Peak Demand Dispatch 2030



MEDIUM DEMAND DISPATCH 2030

For an average day, renewable energy is not curtailed and the system presents no stability issues.

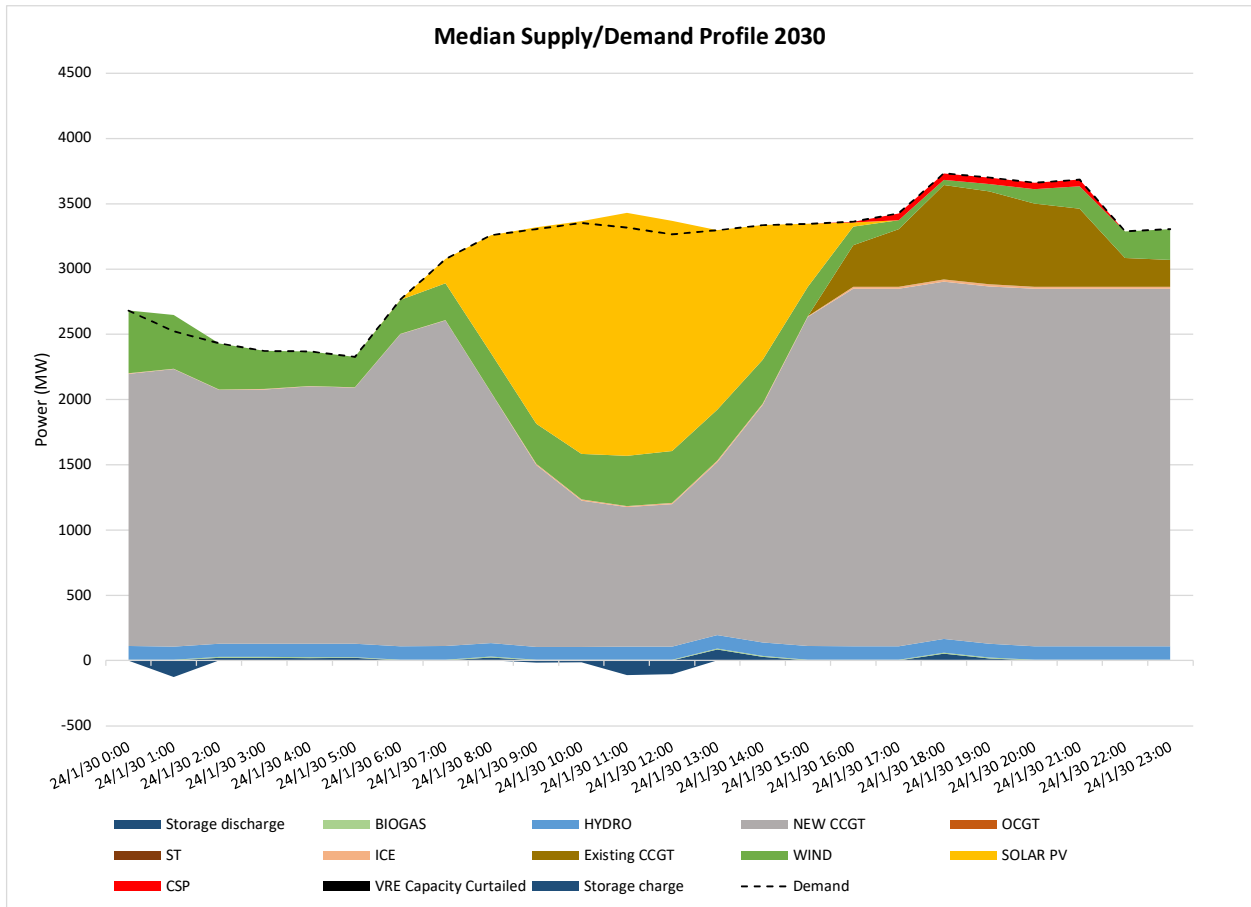


Figure 17: Base Case - Median Demand Dispatch 2030



## 4.2. SENSITIVITY ANALYSIS

In general, investment planning is based on the present knowledge of the system and on projections of the future. It is therefore relevant to verify that the investments to be made in the first years of the plan are robust enough with respect to a possible change in the current situation or projection errors. For this reason, this section of the report analyzes variations of the Base Case.

In the particular case of the Lebanese electricity system, due to the urgency of certain investments that are crucial in filling the generation gap as quickly as possible, the pace of investments must be limited in order to propose a feasible step-by-step plan. This constraint on the pace of investment is an essential condition without which the plan risks being over-ambitious and therefore presenting financing difficulties and delays in the implementation implying either an additional over-costs or the abandonment of the plan. In order to avoid imposing over-restrictive assumptions pertaining to RE and thermal expansion rates, in the Base Case, several variants on these assumptions are studied in this section of the report.

Additional variants which do not constrain RE expansion rates were also studied in order to assess the additional effort that would be made to reach an optimal mix by 2030 that is not constrained by realism.

Regarding the demand projection, understanding current and future demand - which are both highly uncertain due to the current supply deficit and uncertain future economic growth and potentially volatile - is crucial in determining the level of investment in the new generation plan. For this reason, it is important to determine which investments might become stranded assets if demand is found to be lower than projected in the future.

As indicated above, the current regulations in Lebanon do not impose any cost or shadow cost of carbon. However for indicative purposes, scenarios were run to see what would be the influence of such a regulation on the optimal mix.

### 4.2.1. ALTERNATIVE SCENARIOS DEFINITION

#### HIGH RENEWABLE EXPANSION SCENARIO

Compared to the Base Case which employs a constant Solar and Wind expansion rate (250 PV and 200 MW/yr for wind), this scenario supposes increasing annual rates. This increase is attributed to the growth of expertise and the buildup of investor confidence needed to finance projects in Lebanon.

The rates increase as per the following table:

Year	2023	2024	2025	2026	2027	2028	2029	2030
Solar PV (MW/yr)	250	250	400	400	500	500	600	600
Wind (MW/yr)	0	200	200	200	300	300	300	300

Table 10: HRE scenario - High Renewable Expansion rates

#### CARBON-PRICING SCENARIOS

Even if, to date, Lebanon is not subject to a regulated carbon market, global financiers are themselves subject to decarbonization objectives with respect to the investments they make.

The "Carbon Pricing" scenarios, in which Shadow Cost of Carbon is included in the cost minimization function, consider the projections of the carbon price set by the WB and the EIB. These projections aim to limit global warming to less than 2°C by 2100, as agreed in the Climate Change Action Plan, for



the WB and to achieve carbon neutrality by 2050 in line with the European Green Deal for the EIB. These trajectories may seem ambitious for a small, non-interconnected country like Lebanon.

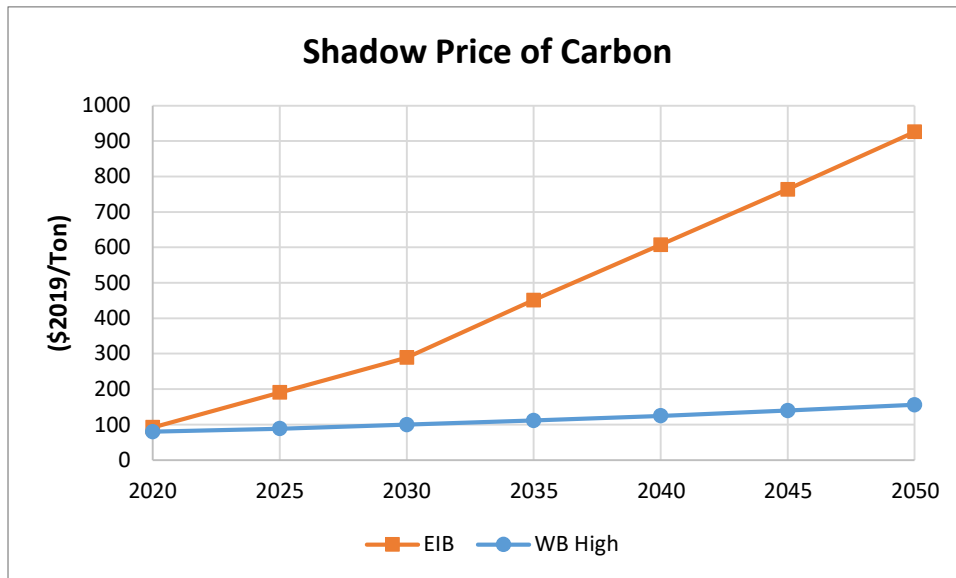


Figure 18: WB & EIB Shadow Prices of Carbon [1] [2]

#### LOW DEMAND GROWTH SCENARIO

In this variant, a lower demand growth is considered, justifiable by the socio-economic situation in Lebanon. It fixes the consumption level at current value until the end of 2025, except for the year 2022 which sees a dip of 4% (the effect of a change in consumer habits – shifting the use of energy consuming appliances over EDL supply hours since EDL tariffs remains lower than private diesels one – with the beginning of 24-hour supply by EDL accompanied by an increase in tariffs), and then assumes a 3% growth per year, starting 2026.

The assumptions pertaining to technical losses on the distribution and transmission networks are maintained, i.e. the decrease of losses on these two fronts. This results in a system demand decrease even without variation of consumption. Thus with the decrease in technical losses of more than half between 2019 and 2030 and the increase in consumer consumption of around ~ 10% (vs 26% for the base case), demand on the system is lighter in 2030 by 1.6% (versus 12% heavier for the base case) compared to 2019.

This “Lower Demand Growth” scenario may appear to be excessively conservative, with respect to the constant level of system demand between 2019 and 2030, however it is important to keep in mind that the number of inhabitants in Lebanon has suffered sharp increases in the past so that if “better days” are expected for Lebanon and the neighboring countries, the number of inhabitants as well as the demand must see a plateau if not even a slight decline before resuming natural growth.

In the following figures, the annual demand & peak demand are depicted under the base case and low growth scenarios respectively:



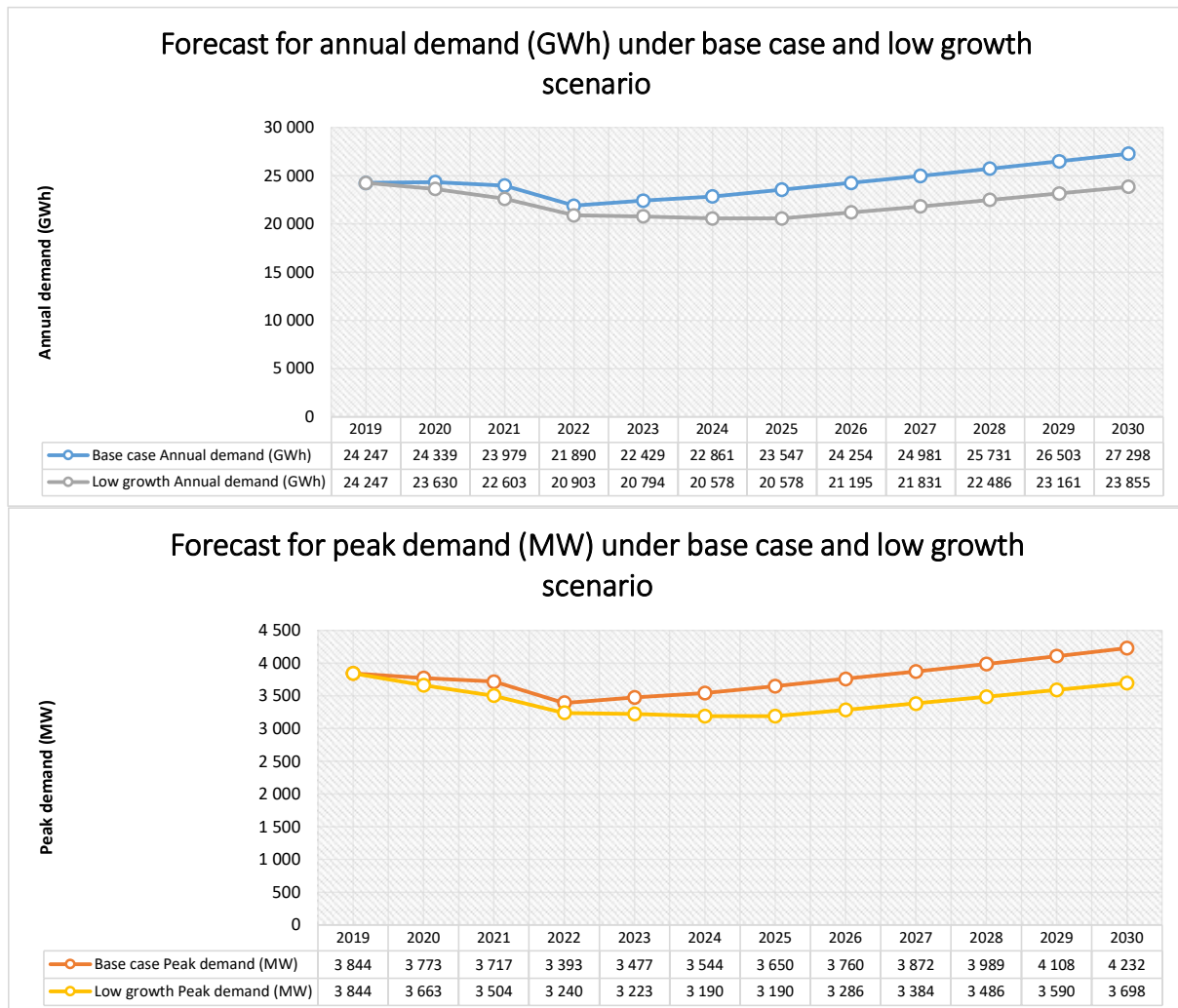


Figure 19: Base Case vs Low Demand Growth forecast for annual demand (GWh) and peak demand (MW)

#### UNCONSTRAINED RENEWABLE INVESTMENTS SCENARIO

This scenario removes all constraints with regards to solar and wind investments. Under these conditions, it would be possible to implement as many MW per year as one can imagine. The objective of such a scenario is to determine the optimal mix for 2030 and optimal share between renewable and thermal generation without subjecting neither renewable nor thermal to any institutional latency or any urgent need for capacity in the first years of the planning horizon. Only results for 2030 are displayed in the report.

Uncapping RE could be even more interesting in scenarios where the carbon price is accounted for in the minimized cost function:

- Unconstrained Renewable Investments & WB Carbon Pricing;
- Unconstrained Renewable Investments & EIB Carbon Pricing.

#### PROGRESSIVE THERMAL INVESTMENTS SCENARIO

This scenario limits thermal investments to 1GW per year in order to take into account Lebanon's economic difficulties and a potential limitation of donor financing ready to fund thermal investments. In this study, the above-mentioned limit was considered over permanent investments only.



#### 4.2.2.SENSITIVITY RESULTS

Figure 20 show the generation and storage target 2030 mixes for each of the studied variants, table 11 gives the 2030 installed capacities per site and table 12 gives some KPIs for these variants such as CRM, RE share, CO2 intensity and costs breakdown.

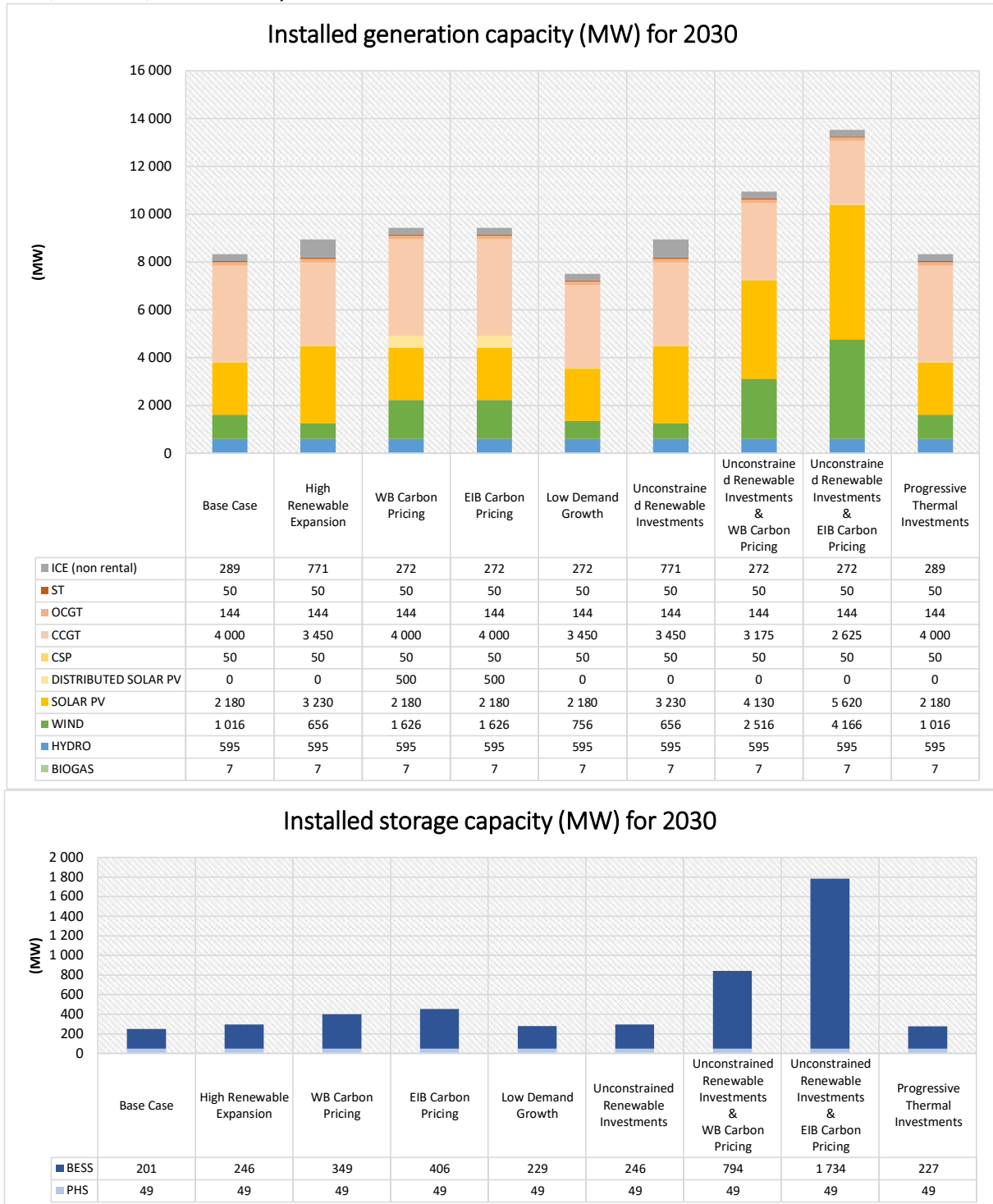


Figure 20: Comparative graph of Generation Mixes for 2030



Location/technologie	Power plant available capacity (MW) Number of FSRU or pipeline	Base Case	High Renewable Expansion	WB Carbon Pricing	EIB Carbon Pricing	Low Demand Growth	Unconstrained Renewable Investments	Unconstrained Renewable Investments & WB Carbon Pricing	Unconstrained Renewable Investments & EIB Carbon Pricing	Progressive Thermal Investments
								WB Carbon Pricing	EIB Carbon Pricing	
DEIR AMMAR	E CCGT RUNNING ON NG	490	490	490	490	490	490	490	490	490
	N FSRU	1	1	1	1	1	1	1	1	1
	N ICE DF NG	249	249	249	249	249	249	249	249	249
	N CCGT 2x1 - E	550	550	550	550	550	550	550	550	550
	N CCGT 3x1 - E	825	825	825	825	825	825	825	825	825
	<b>Total</b>	<b>1 865</b>	<b>1 564</b>	<b>1 865</b>	<b>1 865</b>	<b>1 315</b>	<b>1 564</b>	<b>1 865</b>	<b>1 315</b>	<b>1 865</b>
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA	1	1	1	1	1	1	1	1	1
	N CCGT 3x1 - E	825	825	825	825	825	825	825	825	825
ZOUK	E ICE FO	194	194	194	194	194	194	194	194	194
ZAHRANI	E CCGT RUNNING ON NG	485	485	485	485	485	485	485	485	485
	N FSRU	1	1	1	1	1	1	1	1	1
	N ICE DF NG	17	249	249	249	249	249	249	249	249
	N CCGT 3x1 - E	825	825	825	825	825	825	825	825	825
		<b>Total</b>	<b>1 327</b>	<b>1 559</b>	<b>1 310</b>	<b>1 310</b>	<b>1 310</b>	<b>1 559</b>	<b>1 310</b>	<b>1 310</b>
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74
JIEH	E ICE FO	78	78	78	78	78	78	78	78	78
SOUR	E OCGT	70	70	70	70	70	70	70	70	70
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21
	LITANI	199	199	199	199	199	199	199	199	199
	NAHR BARED	17	17	17	17	17	17	17	17	17
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32
	SAFA	13	13	13	13	13	13	13	13	13
	DARAYA, CHAMRA, YAMOUNEH & BLAT	58	58	58	58	58	58	58	58	58
	JANNEH	54	54	54	54	54	54	54	54	54
	REMAP BALANCE	200	200	200	200	200	200	200	200	200
		<b>Total</b>	<b>595</b>	<b>595</b>	<b>595</b>	<b>595</b>	<b>595</b>	<b>595</b>	<b>595</b>	<b>595</b>
SOLAR PV		2 180	3 230	2 180	2 180	2 180	3 230	4 130	5 620	2 180
DISTRIBUTED SOLAR PV				500	500					
CSP		50	50	50	50	50	50	50	50	50
WIND		1 016	656	1 626	1 626	756	656	2 516	4 166	1 016
BIOGAS	E_BIOGAS_NAAMEH	7	7	7	7	7	7	7	7	7
Storage	BESS (MW/MWh)	201/213	246/246	349/349	406/406	229/229	246/246	794/2552	1734/6936	227/230
	N_JOUN_PHS_UPGRADE_49.3MW_4H	49	49	49	49	49	49	49	49	49
	<b>Total (MW/MWh)</b>	<b>250/410</b>	<b>295/443</b>	<b>398/546</b>	<b>455/603</b>	<b>278/426</b>	<b>295/443</b>	<b>843/2745</b>	<b>1783/7133</b>	<b>276/427</b>

Table 11: Comparative table of Installed Capacity for 2030

	Base Case	High Renewable Expansion	WB Carbon Pricing	EIB Carbon Pricing	Low Demand Growth	Unconstrained Renewable Investments	Unconstrained Renewable Investments & WB Carbon Pricing	Unconstrained Renewable Investments & EIB Carbon Pricing	Progressive Thermal Investments
Capacity reserve margin (MW)	423	420	445	445	368	420	420	1 222	420
Capacity margin (%)	10%	10%	11%	11%	10%	10%	10%	29%	10%
Renewable generated energy (GWh)	8 818	9 498	11 068	11 087	8 091	9 498	14 692	18 423	8 822
Renewable Energy share (%)	32%	35%	41%	41%	34%	35%	54%	68%	32%
CO2 emission (tonne)	7 186 178	6 996 715	6 277 607	6 261 229	6 123 758	6 996 715	4 920 594	3 568 512	7 171 051
CO2 emission intensity (g/kWh)	263	256	230	229	257	256	180	131	263
<b>Costs Breakdown (real 2019 \$000)</b>									
NG Infrastructure Cost (\$000)	166 805	166 805	166 805	166 805	166 805	166 805	150 380	150 380	166 805
Fuel Cost (\$000)	912 457	888 466	797 078	794 998	777 650	888 466	625 093	454 126	910 577
VO&M Cost (incl. Fuel Transport Cost) (\$000)	182 525	173 240	160 934	162 349	155 304	173 240	147 453	112 806	180 796
Emissions Cost (\$000)			641 955	1 811 992			503 185	1 032 723	
Annualized Build Cost (\$000)	604 924	632 298	766 811	770 515	519 969	632 298	1 031 049	1 545 281	606 703
FO&M Cost (\$000)	160 533	155 499	177 055	177 625	146 292	155 499	194 261	236 438	160 793
Retirement Cost (\$000)									
Total Cost (incl. Retirement Cost) (\$000)	2 027 244	2 016 308	2 710 638	3 884 284	1 766 019	2 016 308	2 651 421	3 531 753	2 025 674
Total Cost (excl. Retirement Cost) (\$000)	2 027 244	2 016 308	2 710 638	3 884 284	1 766 019	2 016 308	2 651 421	3 531 753	2 025 674
<b>Indicative Costs excl. Emissions Cost (real 2019 \$)</b>									
Total System Cost (\$/MWh)	74.26	73.87	75.78	75.91	74.03	73.87	78.73	91.70	74.21
Generation Cost (\$/MWh)	40.11	38.89	35.09	35.07	39.11	38.89	28.34	20.80	39.98
<b>SPC (\$/tonne)</b>									
SPC (\$/tonne)	102	102	102	102	102	102	102	102	102
Emissions Cost (\$000)	734 866	715 491	641 955	640 280	626 222	715 491	503 185	364 920	733 319
Total System Cost (\$/MWh)	101.18	100.08	99.30	99.37	100.29	100.08	97.18	105.09	101.07
Generation Cost (\$/MWh)	67.03	65.11	58.61	58.53	65.36	65.11	46.76	34.19	66.85
<b>SPC (\$/tonne)</b>									
SPC (\$/tonne)	289	289	289	289	289	289	289	289	289
Emissions Cost (\$000)	2 079 671	2 024 841	1 816 732	1 811 992	1 772 208	2 024 841	1 424 014	1 032 723	2 075 293
Total System Cost (\$/MWh)	150.45	148.04	142.33	142.29	148.33	148.04	130.92	129.55	150.23
Generation Cost (\$/MWh)	116.30	113.07	101.65	101.45	113.40	113.07	80.50	58.70	116.01

\* Total System Cost (\$/MWh) = (Fuel Cost + VO&M Cost + Emissions Cost + Annualized Build Cost + FO&M Cost + Retirement Cost) / Served Energy  
 \* Generation Cost (\$/MWh) = (Fuel Cost + VO&M Cost + Emissions Cost) / Served Energy

Table 12: Comparative table of Key Performance Indicators for 2030

## HIGH RENEWABLE EXPANSION SCENARIO

As the HRE scenario can, by definition, install more PV compared to the base case, 1050 MW of PV are added to the detriment of 360 MW of wind power. The addition of PV in this scenario reduces the need for base load plants, thus allowing the replacement of a 550 MW CCGT by 482 MW of NG fired Internal Combustion Engines due to their lower CAPEX and the flexibility they offer. 45 MW-1h of additional storage are installed compared to the base case to manage renewable variability and participate in the Capacity Margin Reserves.



The HRE scenario reaches 35% of RE penetration vs 32% for the base case and lowers the total system cost (74.26 for base case to 73.87 \$/MWh).

#### CARBON-PRICING SCENARIOS

Adding a carbon price to the base case encourages investment in renewables. As the PV cap has already been reached for the Base Case, the optimal plan will include more wind and distributed solar which was initially not competitive compared to utility scale solar. The addition of wind participating to the capacity margin makes it possible to withdraw a small amount of reciprocating engines.

#### LOW DEMAND GROWTH SCENARIO

Relative to the base case, the impact of a low increase in demand mainly reduces investing in thermal generation (CCGT of 550 MW) and wind power (260 MW). However, the concerned CCGT is planned for 2028 in the Base Case and not included in the HRE. Lebanon has time to improve its demand forecast and refine its cost assumptions and renewable potential, thus allowing for an update to this study before 2028.

#### UNCONSTRAINED RENEWABLE INVESTMENTS SCENARIO

The Unconstrained RE scenario led to the same results as the HRE for the year 2030. This shows that while the HRE limits the expansion of the RE over the planning horizon, this limitation is small enough so as to not penalize the final mix (unlike the base case).

#### Unconstrained Renewable Investments & Carbon Pricing scenarios

Adding the carbon price of the WB (respectively EIB) moves the least cost plan from the one obtained for the HRE scenario to a plan containing 4.1 GW (respectively 5.6 GW) of PV, 2.5 GW (respectively 4.1GW) of wind power and ~800 MW / 2500 MWh (respectively ~1700 MW / 7000 MWh) of batteries. This increase in renewable and storage comes in substitution of ~ 850 MW (respectively 1400 MW) of NG fired carbon emitting generation.

These renewable and storage growth scenarios are certainly ambitious for such a small system and especially over such a short period of time.

As expected, the impact of carbon pricing, initially designed for systems much larger than Lebanon's, is drastic and would lead to a significant number of investments which may seem over-ambitious in the action window 2020-2030 of this study.

#### PROGRESSIVE THERMAL INVESTMENTS SCENARIO

The added limit of 1 GW/year on thermal investments has shifted some investments over time but had no impact on the target mix compared to the Base Case. This is partly due to the fact that the cap on the annual RE expansion rate is already reached in the Base Case.

#### 4.2.3.SENSITIVITY CONCLUSIONS

The sensitivity analysis conducted above shows that the HRE scenario is the most optimal among the feasible studied scenarios and under the current conditions and regulations. It integrates the largest amount of RE to decarbonize the mix and reach the lowest cost per MWh. This scenario offers a robust plan with respect to the modifications of certain assumptions as observed with the studied variants. In fact, the immediate investments remain unchanged from one variant to another which confirms the fact that these investments will be without regrets in the future.



In the following section of this report, the HRE scenario will be detailed with a structure similar to the previous section devoted to the Base Case.



## 4.3. HIGH RENEWABLE EXPANSION SCENARIO

### 4.3.1. NEW AND RETIRED CAPACITY

The following table depicts the evolution of the added and retired generation capacity within the horizon of this study.

#### TEMPORARY SOLUTIONS

This scenario features the same temporary solutions as the Base Case.

#### PERMANENT SOLUTIONS

Starting 2024, the permanent solutions will start being commissioned. The permanent generation capacity will start to increase, replacing the rental solutions and building system reserves. While the rental generation capacity will be lost in 2024, three 3x1 tri-fuel CCGT units running in open cycle mode (first phase) will add 561 MW of capacity in their three respective sites. Starting 2025 these units will be fully commissioned in closed cycle, increasing their capacity to 825 MW. The commissioning of the CCGTs in open-cycle mode will be met with the decommissioning of the Zouk and Jieh plants.

In tandem with the high RE expansion rate in this plan, the optimizer chose to add 499 MW of ICEs and forego the 2x1 CCGT proposed for the Base Case scenario (in 2028). New ICEs are installed in 2024, 2026, 2029 and 2030. These generators provide higher flexibility than the CCGT, and offer constant efficiency for low load levels, whereas the CCGT's efficiency drops for partial loads (a drop of 6 %pt @ 50% load).

In this variant of the generation plan, Solar PV installation is dramatically increased to reach 3 230 MW (vs 2 180 MW for the Base Case). This heavy reliance on Solar PV is met with a lower Wind penetration, due to its higher build cost. Run of the River Hydro is fixed in this study, with respect to the "Hydro Master Plan". No new CSP capacity was suggested by the optimizer.

Starting 2023, system storage is increased to reach 246 MW/246 MWh of BESS in 2030 and 49 MW/196 MWh of Pumped-Hydro Storage (Joun dam upgrade, 2027).

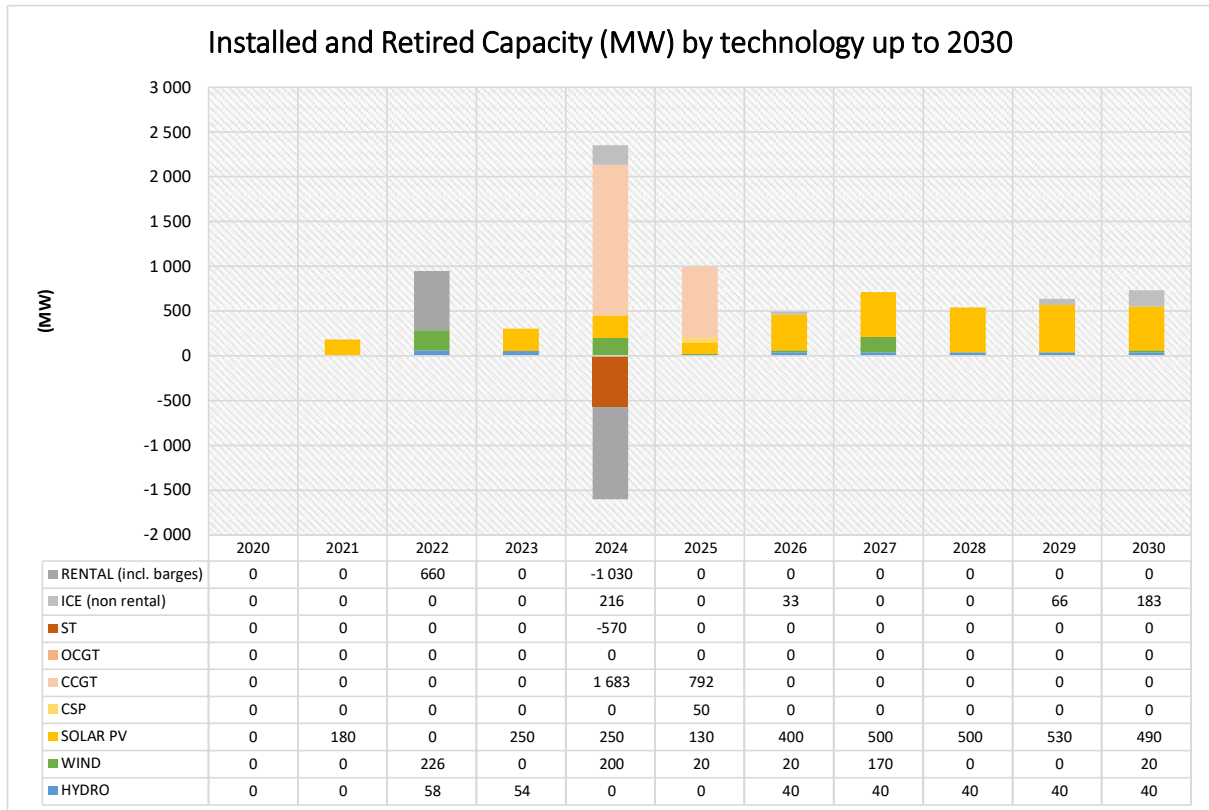


Figure 21: HRE scenario - Installed and Retired Capacity

The HRE optimal generation plan will ramp up the total capacity to 8 952 MW including 4 415 MW of thermal, 595 MW of RoR hydro, 50 MW of CSP, 3 230 MW of solar PV and 656 MW of wind.

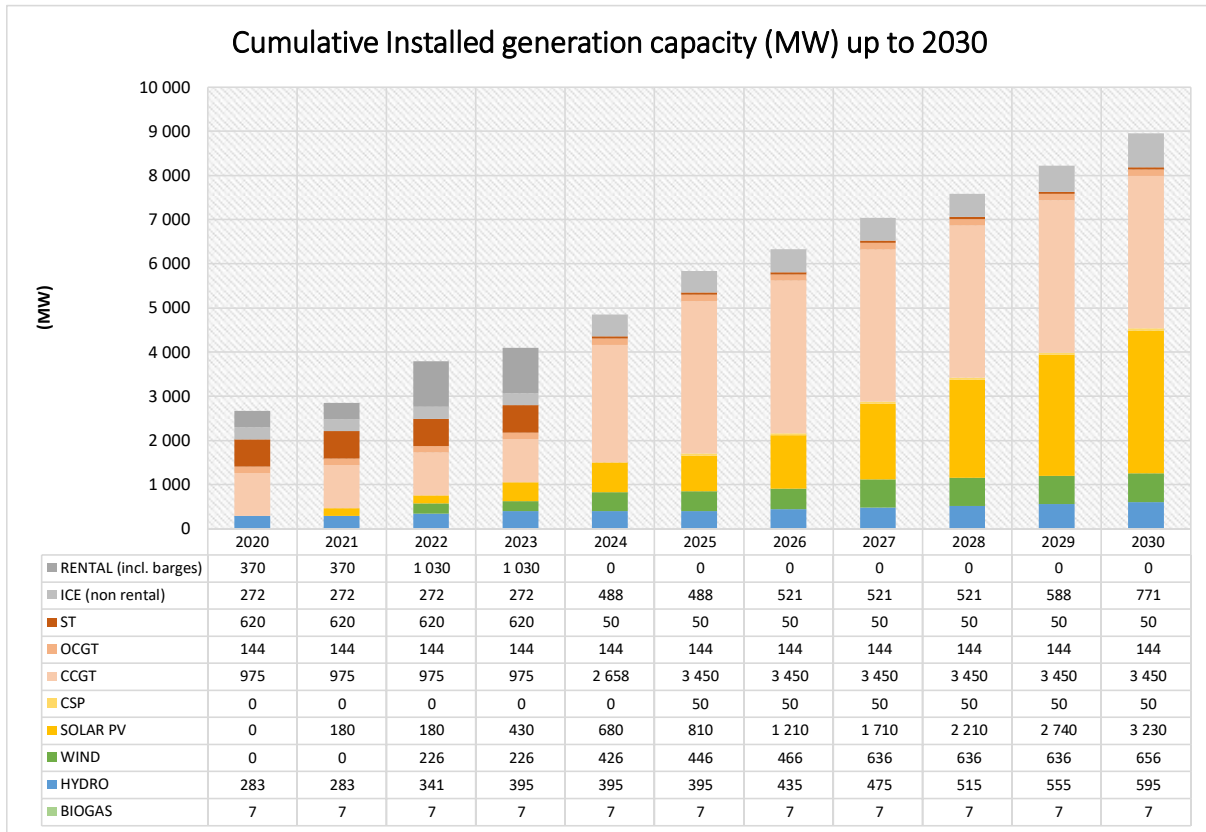


Figure 22: HRE scenario - Cumulative Installed Generation Capacity

The table below provides the schedule for the installation and commissioning of each generation unit proposed in this plan. Note however that all NG fired power plants depend completely on the availability of Natural Gas in the concerned sites, similarly to the Base Case plan.





Location/technologie	Power plant available capacity (MW) Number of FSRU or pipeline	High Renewable Expansion Scenario													
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030			
BINT JBEIL	N ICE FO				83	83									
JIB JANNINE	N ICE FO				83	83									
DEIR AMMAR	E CCGT RUNNING ON GO	490	490	490											
	E CCGT RUNNING ON NG				490	490	490	490	490	490	490	490	490	490	490
	N RENTAL ICE				504	504									
	N FSRU				1	1	1	1	1	1	1	1	1	1	1
	N ICE DF NG					150	150	150	150	150	150	150	150	150	150
	N CCGT 3x1 - E					561	825	825	825	825	825	825	825	825	825
	<b>Total</b>	<b>490</b>	<b>490</b>	<b>994</b>	<b>994</b>	<b>1 201</b>	<b>1 465</b>	<b>1 465</b>	<b>1 465</b>	<b>1 465</b>	<b>1 465</b>	<b>1 465</b>	<b>1 531</b>	<b>1 564</b>	
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50	50	50	50	50	
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA							1	1	1	1	1	1	1	
	N CCGT 3x1 - E							561	825	825	825	825	825	825	
	<b>Total</b>							<b>561</b>	<b>825</b>	<b>825</b>	<b>825</b>	<b>825</b>	<b>825</b>	<b>825</b>	
ZOUK	E ICE BARGE	185	185												
	E ICE FO	194	194	194	194	194	194	194	194	194	194	194	194	194	
	E ST	380	380	380	380										
	<b>Total</b>	<b>759</b>	<b>759</b>	<b>574</b>	<b>574</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	
ZAHRANI	E CCGT RUNNING ON GO	485	485	485											
	E CCGT RUNNING ON NG				485	485	485	485	485	485	485	485	485	485	
	N RENTAL ICE				252	252									
	N FSRU				1	1	1	1	1	1	1	1	1	1	
	N ICE DF NG					66	66	100	100	100	100	100	100	249	
	N CCGT 3x1 - E					561	825	825	825	825	825	825	825	825	
	<b>Total</b>	<b>485</b>	<b>485</b>	<b>737</b>	<b>737</b>	<b>1 112</b>	<b>1 376</b>	<b>1 410</b>	<b>1 410</b>	<b>1 410</b>	<b>1 410</b>	<b>1 410</b>	<b>1 559</b>		
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74	74	74	74		
JIEH	E ICE BARGE	185	185												
	E ICE FO	78	78	78	78	78	78	78	78	78	78	78	78		
	E ST	190	190	190	190										
	N RENTAL ICE				108	108									
	<b>Total</b>	<b>453</b>	<b>453</b>	<b>376</b>	<b>376</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>		
SOUR	E OCGT	70	70	70	70	70	70	70	70	70	70	70	70		
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21	21	21	21		
	LITANI	199	199	199	199	199	199	199	199	199	199	199	199		
	NAHR BARED	17	17	17	17	17	17	17	17	17	17	17	17		
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32	32	32	32		
	SAFA	13	13	13	13	13	13	13	13	13	13	13	13		
	DARAYA, CHAMRA, YAMOUNEH & BLAT			58	58	58	58	58	58	58	58	58	58		
	JANNEH				54	54	54	54	54	54	54	54	54		
	REMAP BALANCE						40	80	120	160	200				
		<b>Total</b>	<b>283</b>	<b>283</b>	<b>341</b>	<b>395</b>	<b>395</b>	<b>435</b>	<b>475</b>	<b>515</b>	<b>555</b>	<b>595</b>	<b>635</b>		
SOLAR PV		180	180	430	680	810	1 210	1 710	2 210	2 740	3 230				
CSP	N_CSP_STORAGE_7.5H_CF_27_MAX_1187					50	50	50	50	50	50	50			
WIND			226	226	426	446	466	636	636	636	636	656			
BIOGAS	E_BIOGAS_NAAMEH	7	7	7	7	7	7	7	7	7	7	7			
Storage	BESS (MW/MWh)				246/246	246/246	246/246	246/246	246/246	246/246	246/246	246/246	246/246		
	N_JOUN_PHS_UPGRADE_49.3MW_4H						49	49	49	49	49	49			
	<b>Total (MW/MWh)</b>				<b>246/246</b>	<b>246/246</b>	<b>246/246</b>	<b>295/443</b>	<b>295/443</b>	<b>295/443</b>	<b>295/443</b>	<b>295/443</b>			

Table 13: HRE scenario - Installed Capacity Schedule

	High Renewable Expansion Scenario										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
<b>Total installed generation capacity by technology (MW)</b>											
RENTAL (incl. barges)	370	370	1 030	1 030							
ICE (non rental)	272	272	272	272	488	488	521	521	521	588	771
ST	620	620	620	620	50	50	50	50	50	50	50
CCGT	144	144	144	144	144	144	144	144	144	144	144
CCGT	975	975	975	975	2 658	3 450	3 450	3 450	3 450	3 450	3 450
HYDRO	283	283	341	395	395	395	435	475	515	555	595
SOLAR PV		180	180	430	680	810	1 210	1 710	2 210	2 740	3 230
DISTRIBUTED SOLAR PV											
CSP						50	50	50	50	50	50
WIND			226	226	426	446	466	636	636	636	656
BIOGAS	7	7	7	7	7	7	7	7	7	7	7
	<b>Total (MW)</b>	<b>2 671</b>	<b>2 851</b>	<b>3 795</b>	<b>4 099</b>	<b>4 848</b>	<b>5 840</b>	<b>6 333</b>	<b>7 043</b>	<b>7 583</b>	<b>8 220</b>
<b>Total storage capacity by technology (MW)</b>											
PHS (MW/MWh)							49/197	49/197	49/197	49/197	49/197
BESS (MW/MWh)					246/246	246/246	246/246	246/246	246/246	246/246	246/246
	<b>Total (MW/MWh)</b>				<b>246/246</b>	<b>246/246</b>	<b>246/246</b>	<b>295/443</b>	<b>295/443</b>	<b>295/443</b>	<b>295/443</b>

Table 14: HRE scenario - Cumulative Installed Capacity by generation type



#### 4.3.2. CAPACITY RESERVE MARGIN

The HRE generation plan will ramp up the thermal firm capacity to 4 154 MW. Additionally, hydro firm capacity contribution will increase to 59 MW, solar will account for 291 MW, CSP for 50 MW, wind for 46 MW, and storage for 49 MW.

The system will start building up CRM in 2024. By 2026 it will reach its maximum of 11%. Throughout the rest of the study’s horizon, CRM will taper off as demand increases slightly faster than the new capacity introduced into the mix (ICEs, solar, wind and storage).

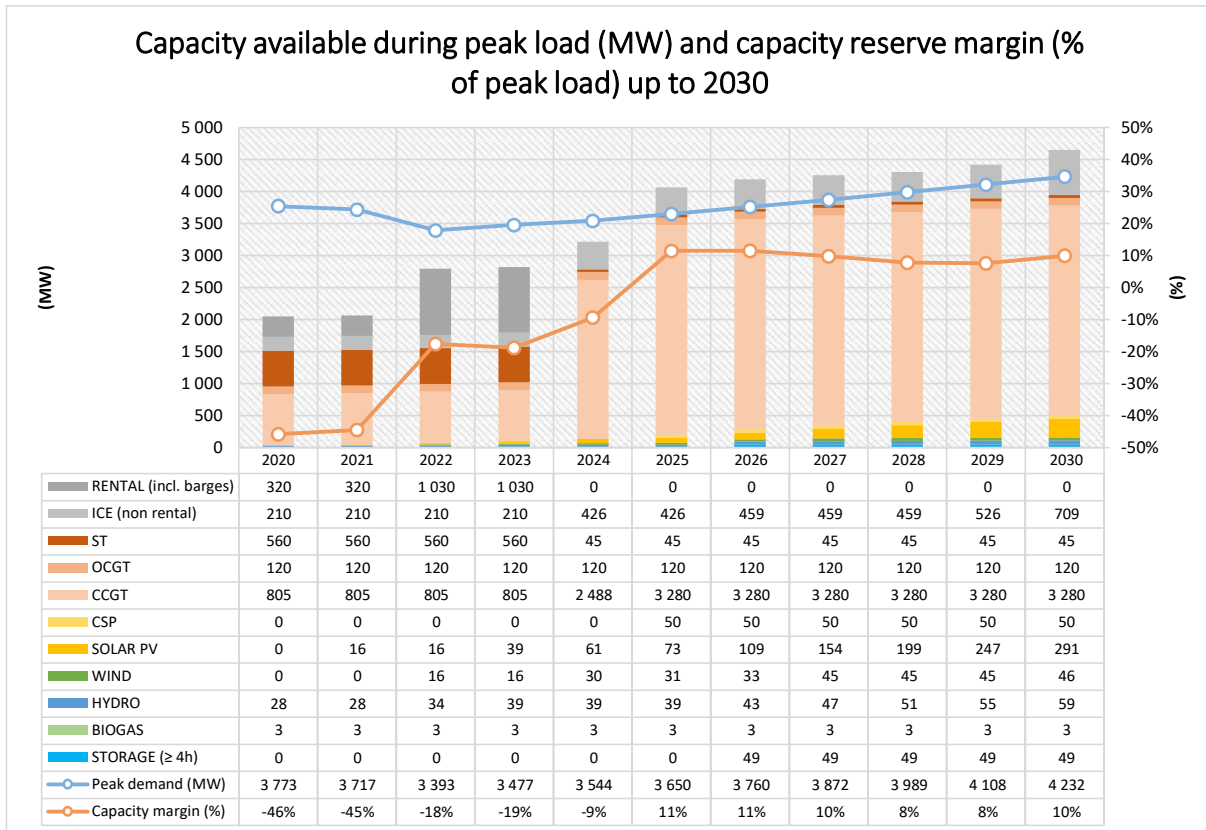


Figure 23: HRE scenario - Capacity available during peak load and capacity reserve margin



### 4.3.3.GENERATION MIX

Under this plan, RE penetration will increase from 4% in 2020 to 35% in 2030.

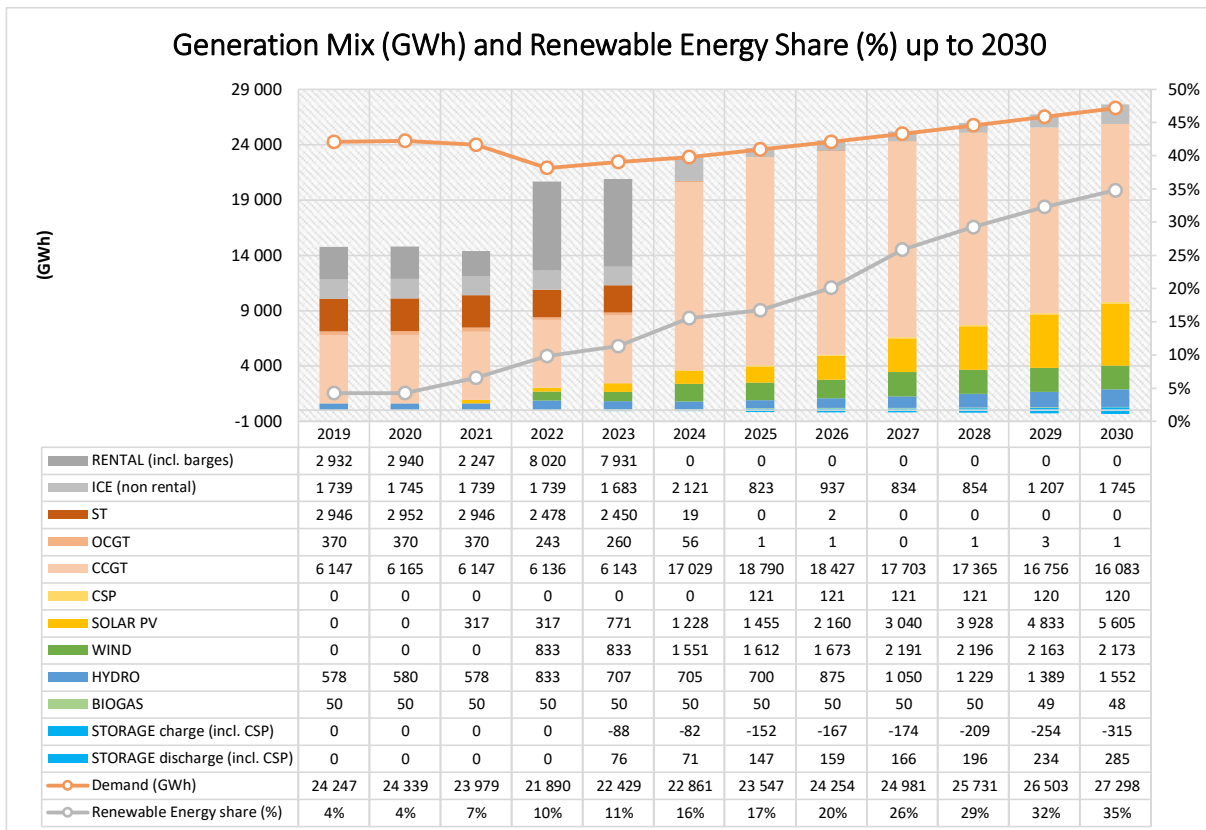


Figure 24: HRE scenario - Generation Mix



#### 4.3.4. CAPACITY FACTOR

Lately the OCGTs have had a low capacity factor of 30%, due to their low efficiency and high variable costs. Their capacity factor will go down to ~0% in 2024, and they will start serving as extreme peaker plants and capacity margin reserves, always running on LFO.

Existing and new ICEs will contribute on base, mid and peak loads. They will provide flexibility that is essential for a high RE penetration in the system, and have a capacity factor of CF > 20%. As for CCGTs, the new units will have a high capacity factor as base load generators (CF > 75%), while the older ones will serve as peakers, and help build Capacity Reserve Margin (CF < 15%).

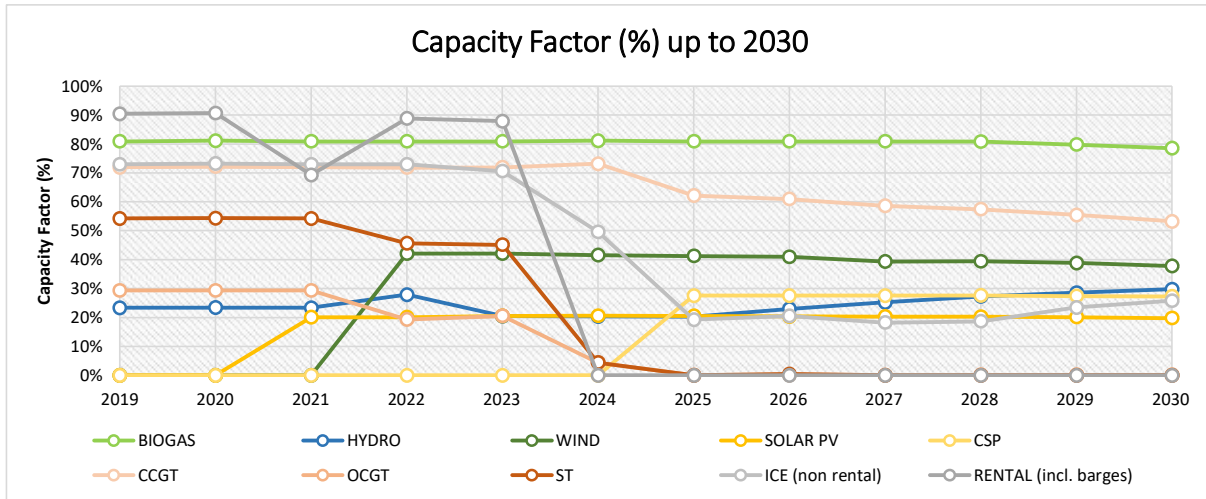


Figure 25: HRE scenario - Average Capacity factor projection per technology

#### 4.3.5. UNSERVED ENERGY

In 2025, with the full commissioning of the 3 CCGTs, the loss of load expectation becomes negligible. This means that the system would have practically reached a 24/24h supply, in absence of any contingencies.

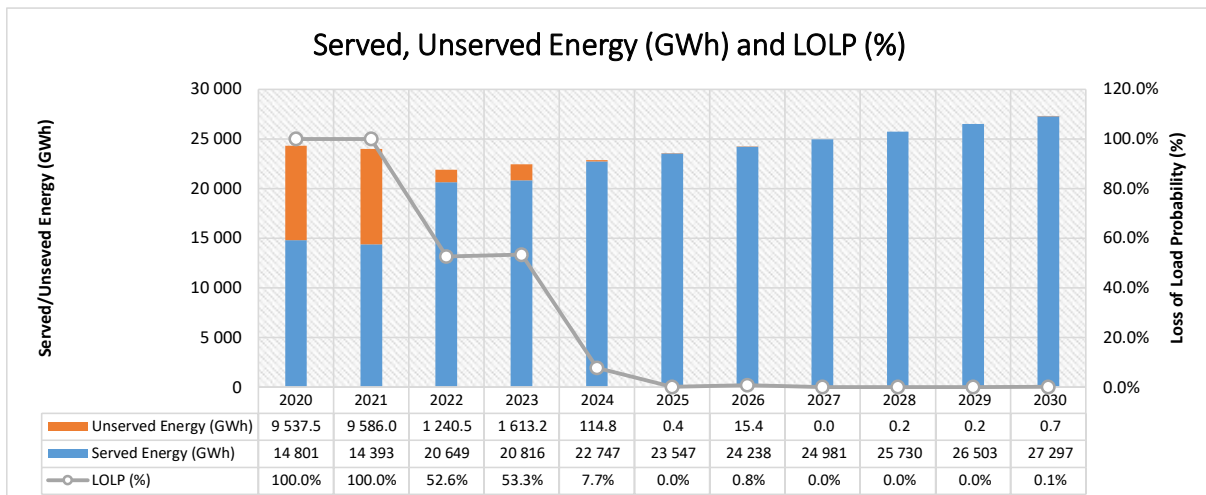


Figure 26: HRE scenario - Served, Unseved energy, and LOLP projections

The following CDF graphs show that in 2024, the HRE plan has a better Supply/Demand balance than its Base Case counterpart. Years with the temporary solution remain unchanged.

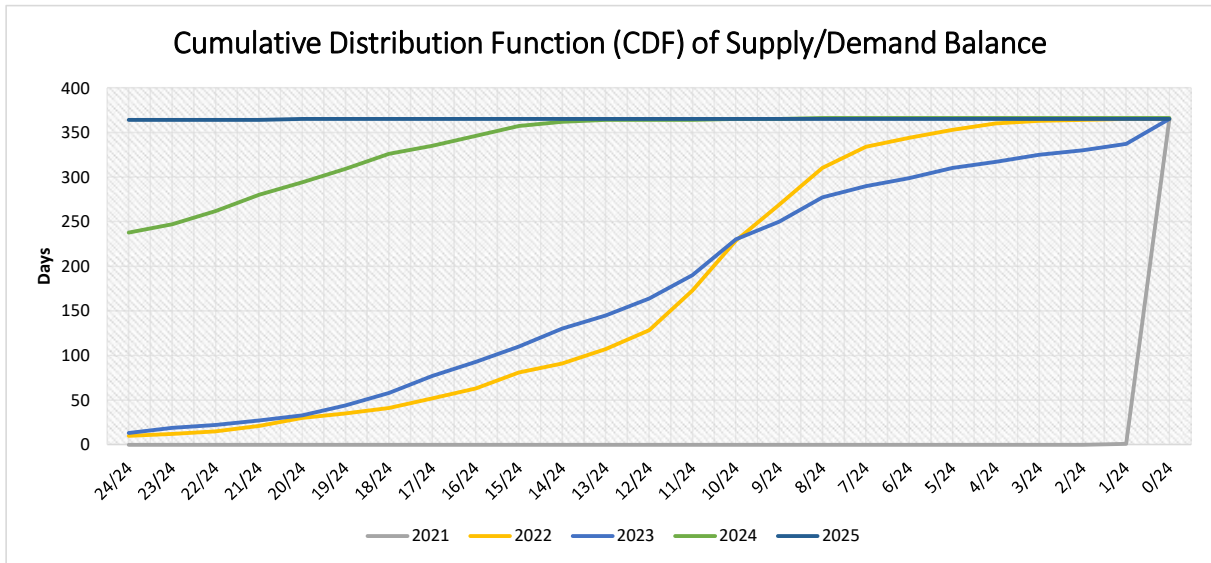


Table 15: HRE scenario - Cumulative Distribution Function of Supply/Demand Balance

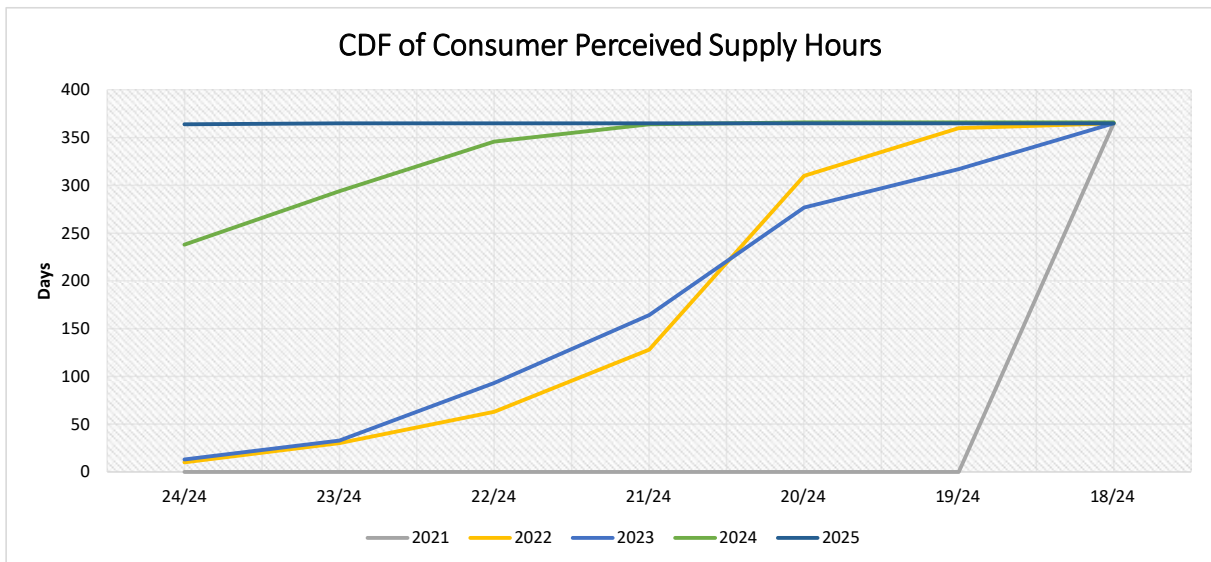


Table 16: HRE scenario - Cumulative Distribution Function of consumer perceived supply hours



#### 4.3.6. EMISSIONS AND FUEL CONSUMPTION

The following graph illustrates the variation of CO<sub>2</sub> emission generated by fuel consumption throughout the horizon of this study. The evolution of emissions and emission intensity are in line with those of the Base Case plan.

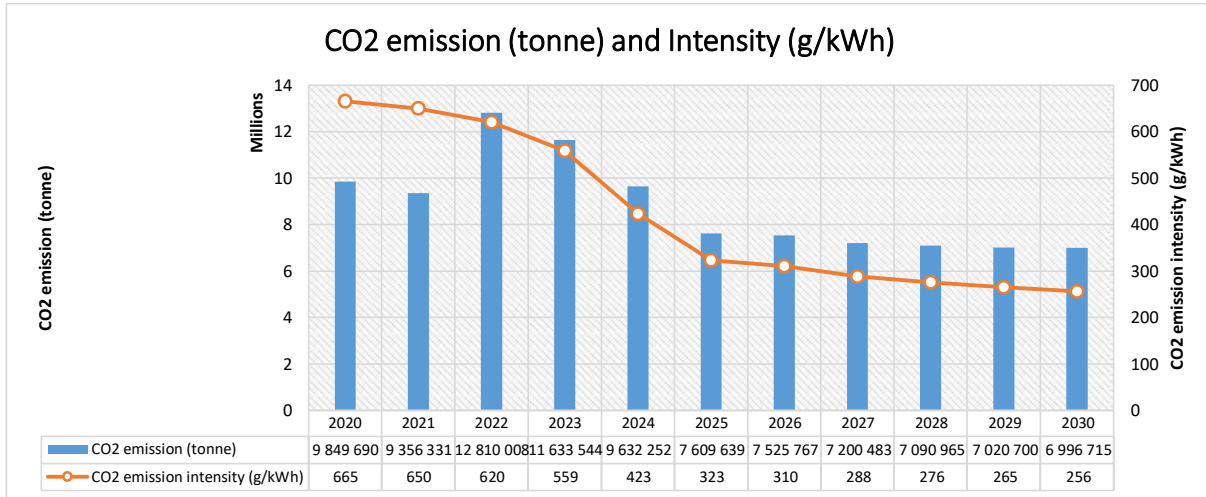


Figure 27: HRE scenario - CO<sub>2</sub> emission and intensity projection

Figure 28 details the fuel consumption (offtake in TJ) and the average heat rate for each fuel type, in the 2020 – 2030 interval.

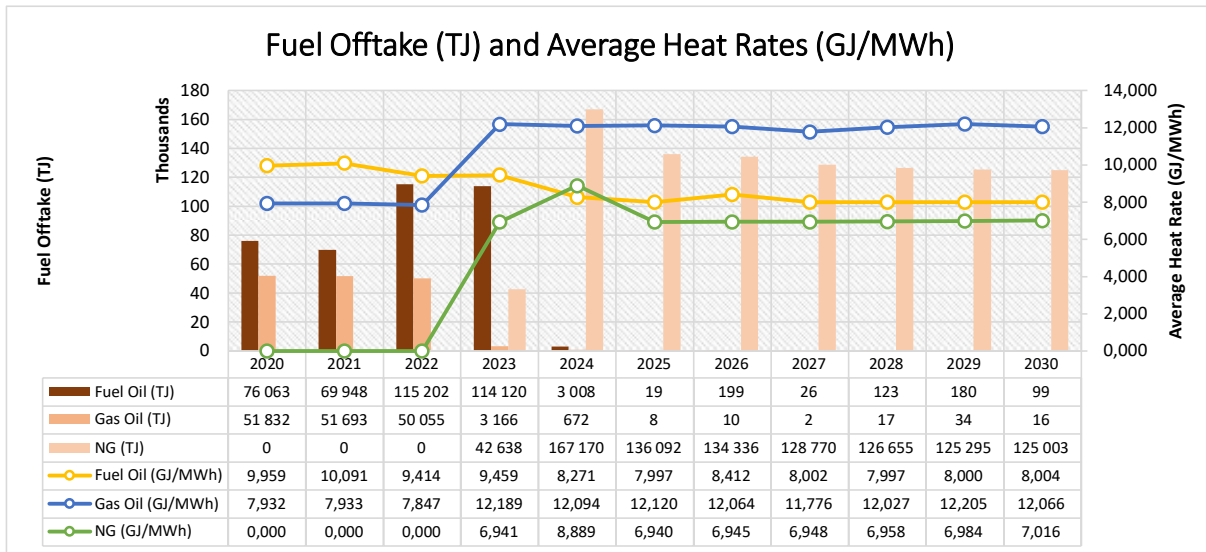


Figure 28: HRE scenario - Fuel Offtake and Average Heat Rate per fuel type

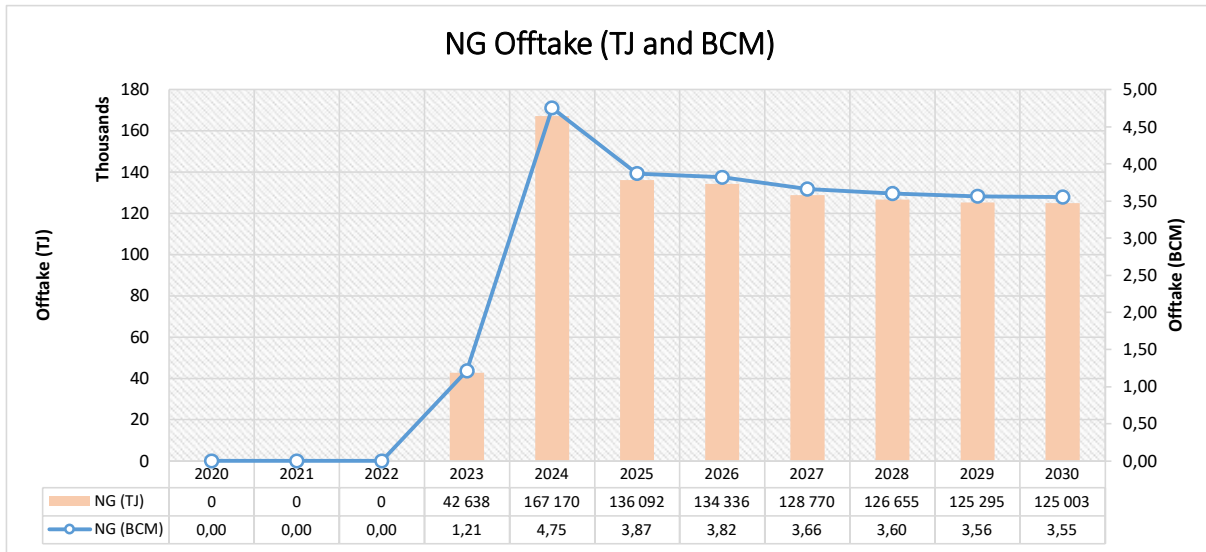


Figure 29: HRE scenario - NG Off-take

#### 4.3.7. COST BREAKDOWN & BUDGET ESTIMATES

The graph below shows a cost breakdown for the Least Cost Generation Plan (HRE scenario).

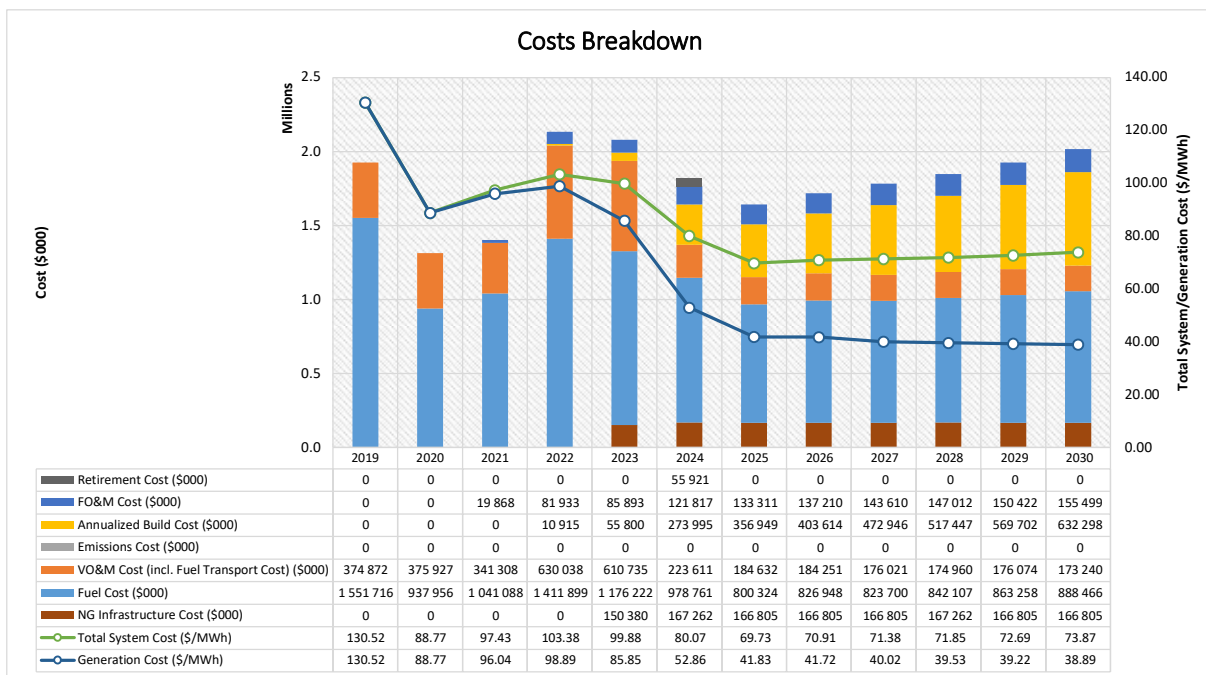


Figure 30: HRE scenario - Costs Breakdown



High Renewable Expansion Scenario											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
<b>Costs Breakdown (real 2019 \$000)</b>											
NG Infrastructure Cost (\$000)				150 380	167 262	166 805	166 805	166 805	167 262	166 805	166 805
Fuel Cost (\$000)	937 956	1 041 088	1 411 899	1 176 222	978 761	800 324	826 948	823 700	842 107	863 258	888 466
VO&M Cost (incl. Fuel Transport Cost) (\$000)	375 927	341 308	630 038	610 735	223 611	184 632	184 251	176 021	174 960	176 074	173 240
Emissions Cost (\$000)											
Annualized Build Cost (\$000)			10 915	55 800	273 995	356 949	403 614	472 946	517 447	569 702	632 298
FO&M Cost (\$000)		19 868	81 933	85 893	121 817	133 311	137 210	143 610	147 012	150 422	155 499
Retirement Cost (\$000)				0	55 921						
<b>Total Cost (incl. Retirement Cost) (\$000)</b>	<b>1 313 883</b>	<b>1 402 263</b>	<b>2 134 785</b>	<b>2 079 030</b>	<b>1 821 367</b>	<b>1 642 021</b>	<b>1 718 829</b>	<b>1 783 082</b>	<b>1 848 789</b>	<b>1 926 262</b>	<b>2 016 308</b>
<b>Total Cost (excl. Retirement Cost) (\$000)</b>	<b>1 313 883</b>	<b>1 402 263</b>	<b>2 134 785</b>	<b>2 079 030</b>	<b>1 765 446</b>	<b>1 642 021</b>	<b>1 718 829</b>	<b>1 783 082</b>	<b>1 848 789</b>	<b>1 926 262</b>	<b>2 016 308</b>
<b>Indicative Costs excl. Emissions Cost (real 2019 \$)</b>											
Total System Cost (\$/MWh)	88.77	97.43	103.38	99.88	80.07	69.73	70.91	71.38	71.85	72.69	73.87
Generation Cost (\$/MWh)	88.77	96.04	98.89	85.85	52.86	41.83	41.72	40.02	39.53	39.22	38.89
<b>Indicative Costs incl. Emissions Cost with high WB SPC (real 2019 \$)</b>											
SPC (\$/tonne)	82	84	86	88	89	91	92	96	98	100	102
Emissions Cost (\$000)	805 792	784 566	1 100 370	1 023 106	856 954	692 571	700 329	692 149	696 124	703 585	715 491
Total System Cost (\$/MWh)	143.21	151.93	156.67	149.03	117.75	99.15	99.81	99.08	98.91	98.24	100.08
Generation Cost (\$/MWh)	143.21	150.55	152.17	134.99	90.53	71.24	70.61	67.73	66.58	65.77	65.11
<b>Indicative Costs incl. Emissions Cost with EIB SPC (real 2019 \$)</b>											
SPC (\$/tonne)	93	112	132	152	171	191	211	230	250	270	289
Emissions Cost (\$000)	912 156	1 050 592	1 690 483	1 764 168	1 650 237	1 453 465	1 585 546	1 658 713	1 773 029	1 893 621	2 024 841
Total System Cost (\$/MWh)	150.39	170.42	185.25	184.63	152.62	131.46	136.33	137.78	140.76	144.15	148.04
Generation Cost (\$/MWh)	150.39	169.04	180.75	170.60	125.41	103.56	107.13	106.42	108.44	110.68	113.07

Table 17: HRE scenario - Costs Breakdown (indicative costs including SPC)

The table below provides a budget estimates for each of the suggested projects in the Least Cost Generation Plan HRE scenario:

High Renewable Expansion Scenario						
Site	Investment	Capacity (MW)	Date *	Cost	Budget (2019 \$1M)	Comments
Deir Ammar	Addition of a FSRU		2023	206 000 \$/day	752	FSRU Capacity Charge over 10 years
	Switch the existing CCGT to NG		2023			
	Tri-fuel CCGT 3x1 in open cycle	561	2024	800 \$/kW	660	Build Cost
	Full commission Tri-fuel CCGT 3x1	+264	2025			
	Internal Combustion Engine (Dual Fuel)	150 MW in 2024 +66 MW in 2029 +33 MW in 2030	2024 2029 2030	883 \$/kW	174 M\$ in 2024 60 M\$ in 2029 30 M\$ in 2030	Build Cost
Selaata	Pipeline from Deir Ammar to Selaata		2024	45 000 \$/day	165	Pipeline Capacity Charge over 10 years
	Tri-fuel CCGT 3x1 in open cycle	561	2024	800 \$/kW	660	Build Cost
	Full commission Tri-fuel CCGT 3x1	+264	2025			
Zouk	Retirement of the old Steam Turbines		2024	59 \$/kW	36	Retirement Cost
Zahrani	Addition of a FSRU		2023	206 000 \$/day	752	FSRU Capacity Charge over 10 years
	Switch the existing CCGT to NG		2023			
	Tri-fuel CCGT 3x1 in open cycle	561	2024	800 \$/kW	660	Build Cost
	Full commission Tri-fuel CCGT 3x1	+264	2025			
	Internal Combustion Engine (Dual Fuel)	66 MW in 2024 +33 MW in 2026 +150 MW in 2030	2024 2026 2030	883 \$/kW	60 M\$ in 2024 30 M\$ in 2026 170 M\$ in 2030	Build Cost
Jieh	Retirement of the old Steam Turbines		2024	59 \$/kW	20	Retirement Cost
Solar PV	+250 MW in 2023	3 050	2023 till 2030	Average of 652.5 \$/kW from 2023 to 2030	164 M\$ in 2023	Average Build Cost per year
	+250 MW in 2024				164 M\$ in 2024	
	+130 MW in 2025				85 M\$ in 2025	
	+400 MW in 2026				261 M\$ in 2026	
	+500 MW in 2027				327 M\$ in 2027	
	+500 MW in 2028				327 M\$ in 2028	
	+530 MW in 2029				346 M\$ in 2029	
+490 MW in 2030	320 M\$ in 2030					
Wind	+200 MW in 2024	430	2024 till 2030	Average of 1 200 \$/kW from 2024 to 2030	240 M\$ in 2024	Average Build Cost per year
	+20 MW in 2025				24 M\$ in 2025	
	+20 MW in 2026				24 M\$ in 2026	
	+170 MW in 2027				204 M\$ in 2027	
	+20 MW in 2030				24 M\$ in 2030	
Joun Pumped Hydro Storage	Upgrade to PHS	+49 MW/4h	2026	Estimate for building lower reservoir 420 \$/kW	21	Lower reservoir Build Cost
Battery Energy Storage System		+246 MW/246 MWh	2023 till 2030	453 \$/kW 1h	112	Build Cost

\* Dates reference beginning of year

Table 18: HRE scenario - Budget Estimates





#### 4.3.8. SPINNING RESERVE

The graph below depicts the spinning reserve requirements for the generation mix. These are the same as the requirements for the Base Case plan variant.

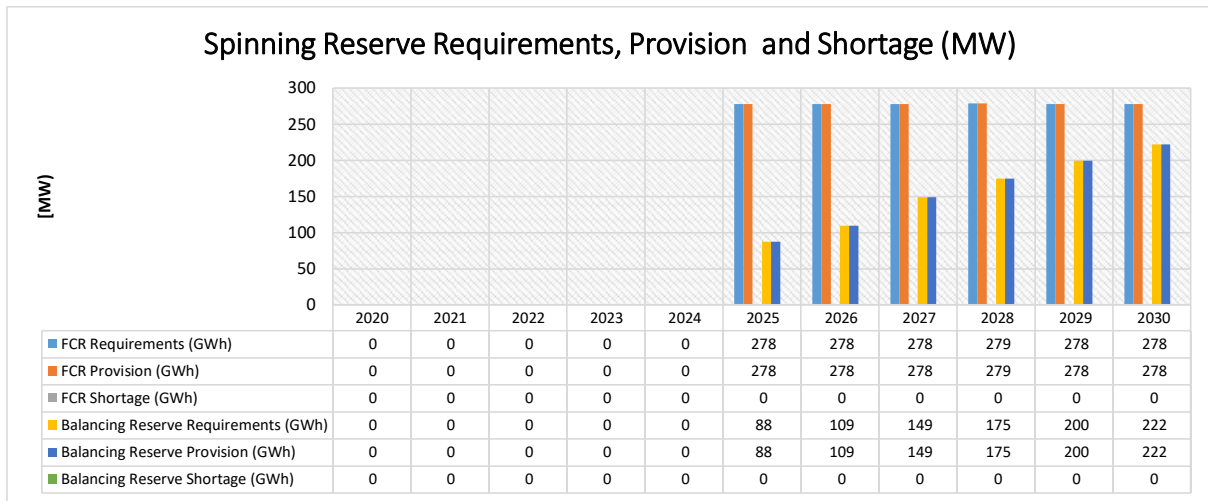


Figure 31: HRE scenario - Spinning Reserve Requirements, Provision and Shortage



#### 4.3.9. MAINTENANCE SCHEDULING

The graph below depicts the available capacity reserve throughout the year 2030 for the HRE scenario. Like the Base Case scenario, it would be convenient to take advantage of the low system load between March and June to perform significant maintenance works with no impact.

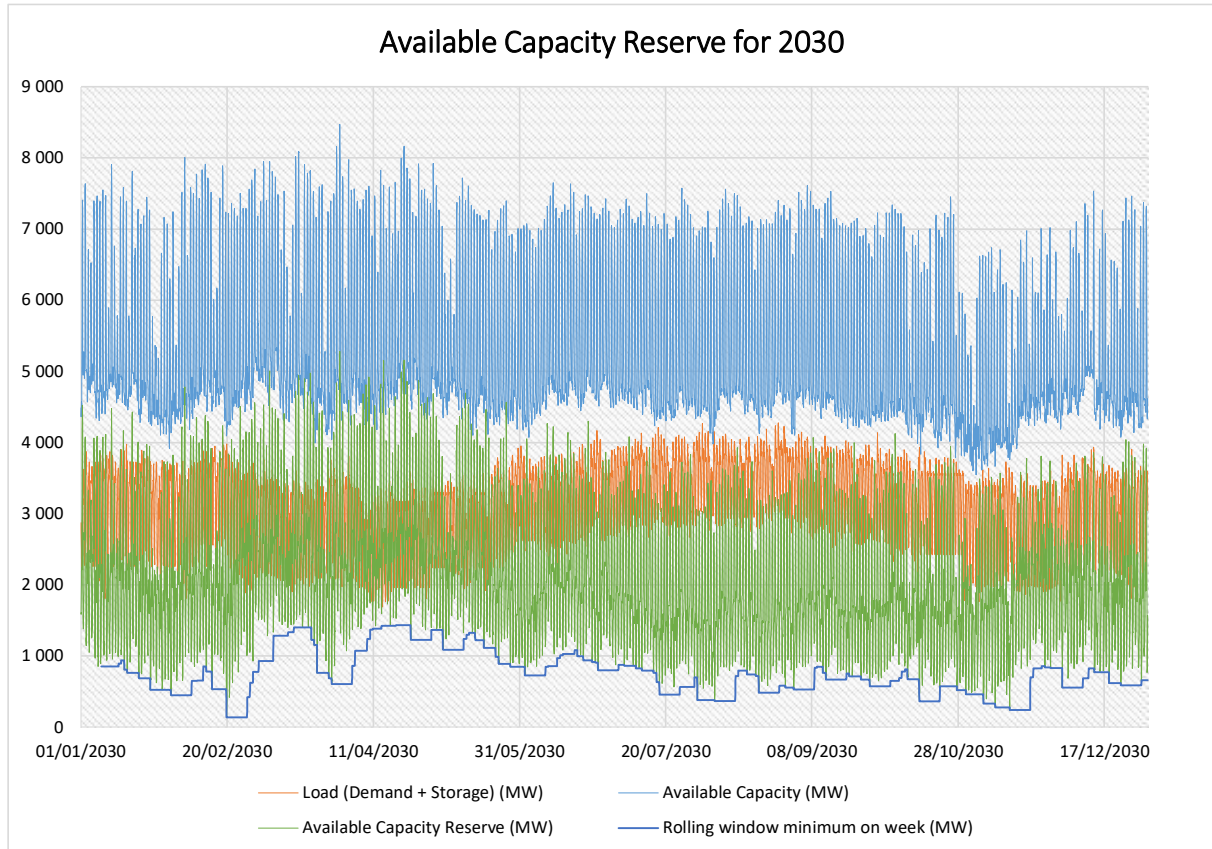


Figure 32: HRE scenario - Available Capacity Reserve for 2030



#### 4.3.10. OPERABILITY & RENEWABLE PENETRATION

The graph below shows the optimal Short Term (ST) dispatch for the year 2030, on an hourly basis. Note that the new CCGTs provide the base load, while Solar PV and wind experience mild curtailment (1.6% Solar PV and 3% Wind). The rest of the renewable sources are in line with the analysis of the Base Case plan.

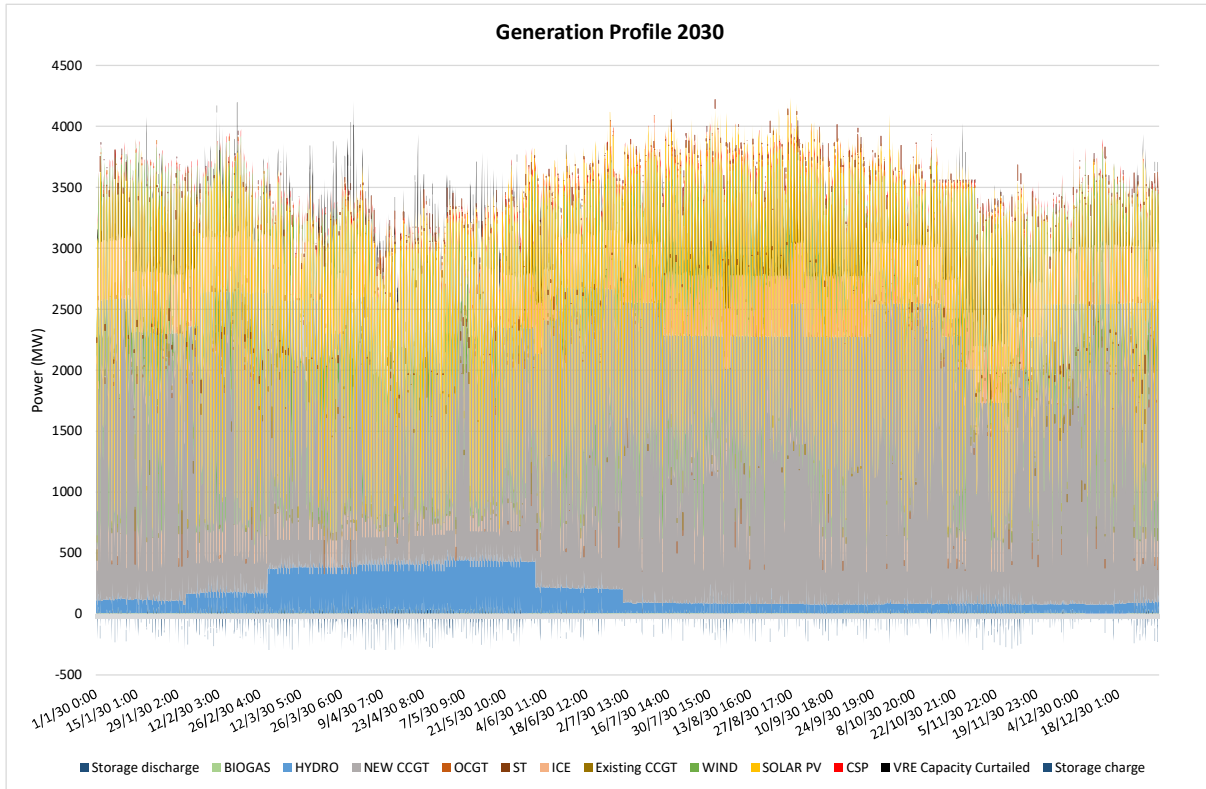


Figure 33: HRE scenario - Generation Profile 2030



### PEAK DEMAND DISPATCH 2030

The following figure shows the hourly dispatch of the generation during the annual peak load. The new CCGTs remain the base load power plants throughout the day, while RoR Hydro contribution is minimal. During noon hours, the fuel fired power plants' setpoint is reduced in order to give way to wind and solar PV. The ICEs and low efficiency CCGTs (existing units) replace solar PV in the afternoon in response to the high demand.

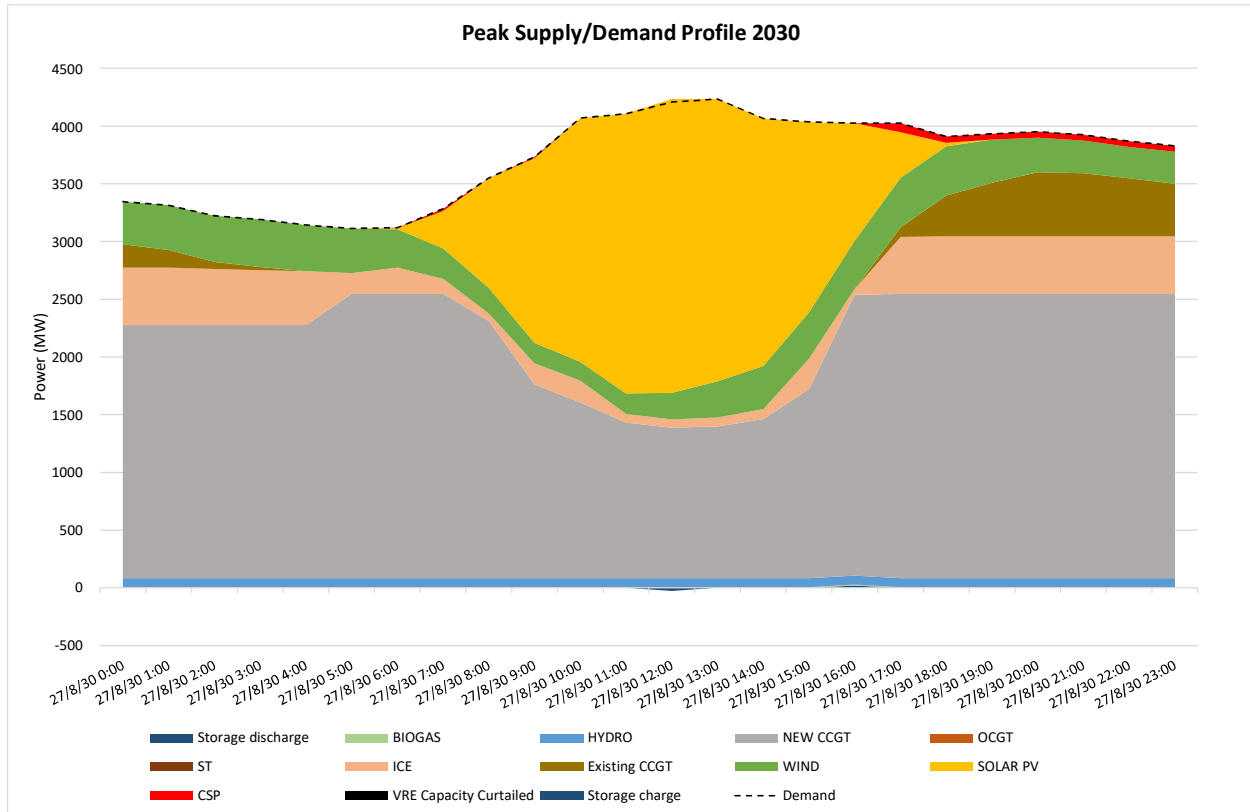


Figure 34: HRE scenario - Peak Demand Dispatch 2030



### OFF-PEAK DEMAND DISPATCH 2030

During off-peak days, the same analysis remains applicable, with the particularity that Variable Renewable Energy is curtailed during high solar production periods. In order to guarantee enough system inertia for system stability, thermal units are run at minimum technical level during sunny hours. However, the annual VRE curtailment represents around 2% of the available energy and is not a reason for concern given the conservative approach used to determine system inertia requirements.

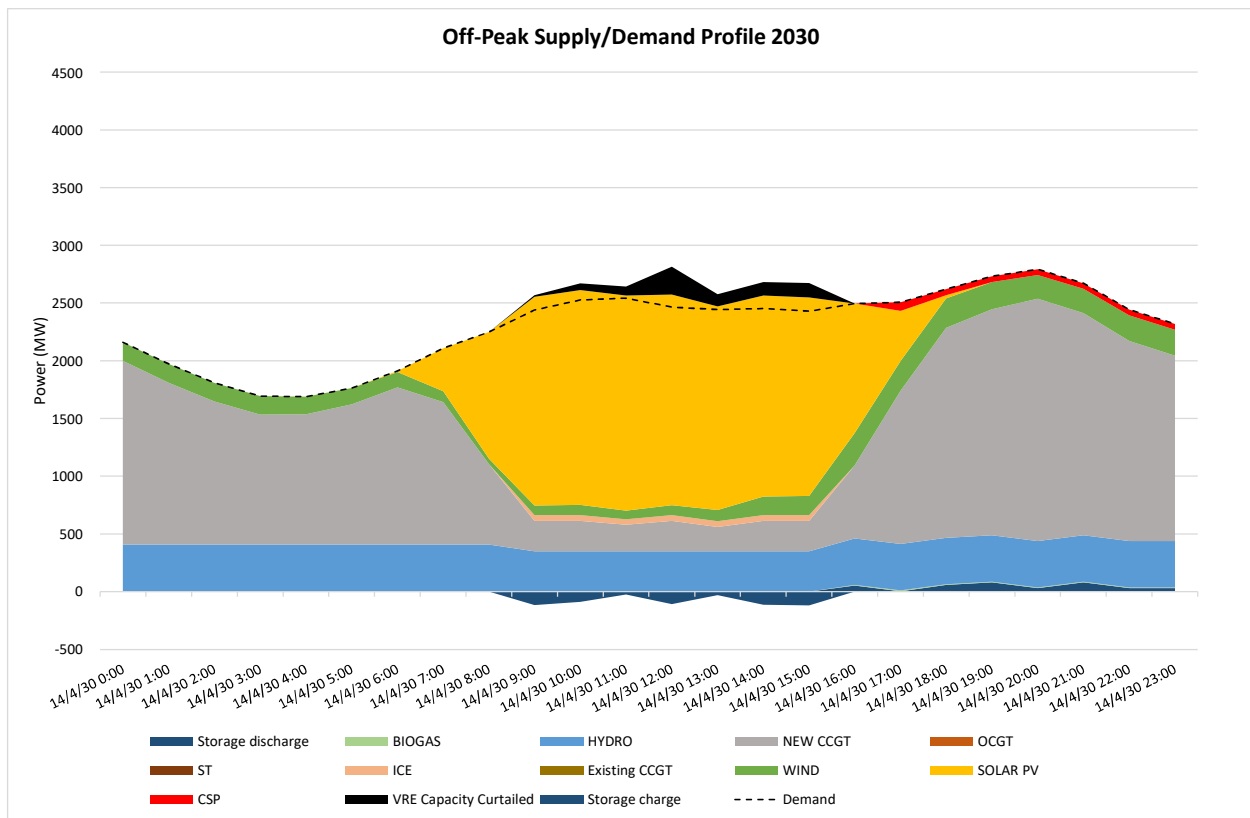


Figure 35: HRE scenario - Off-Peak Demand Dispatch 2030



### MEDIUM DEMAND DISPATCH 2030

For an average day, RE curtailment is minimal, and limited to noon time. This curtailment level remains reasonable for a system with such a high RE penetration factor especially without any interconnections. Despite this curtailment the proposed generation mix remains efficient and optimal.

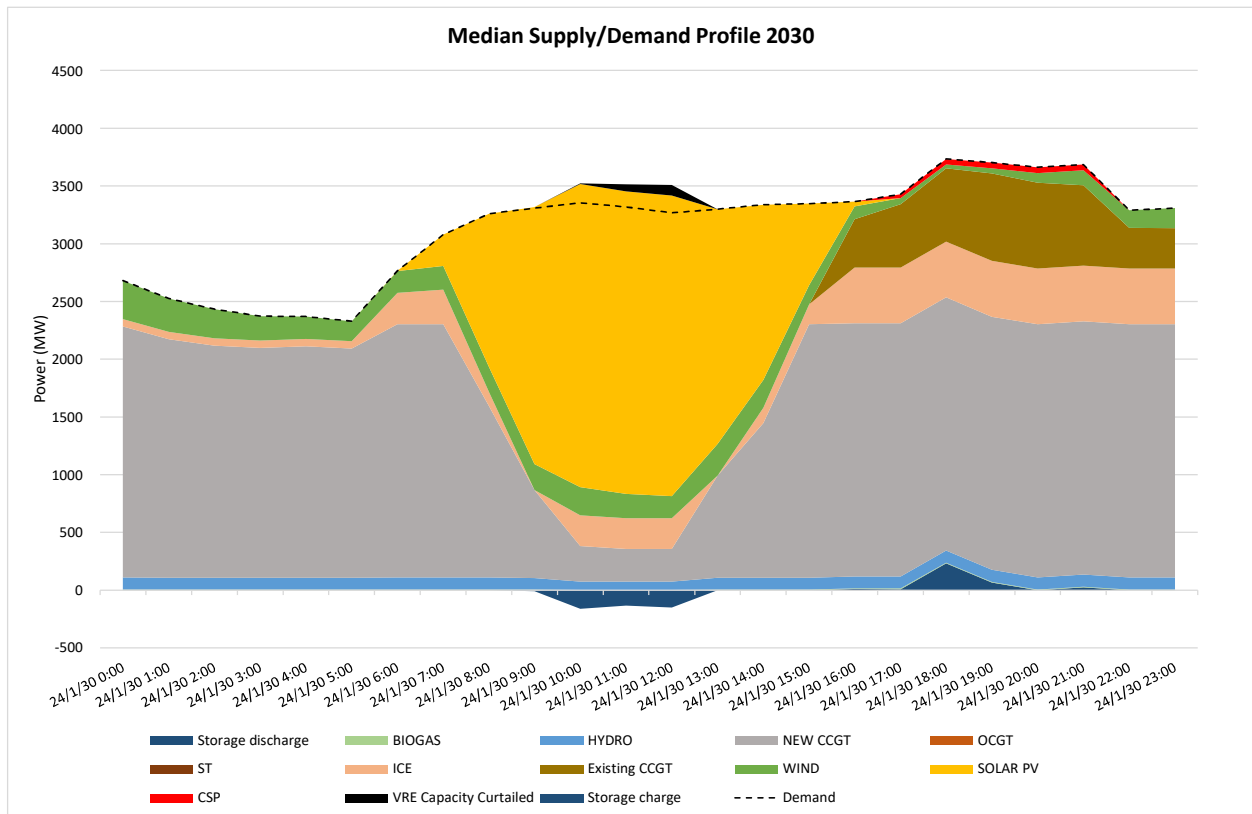


Figure 36: HRE scenario - Median Demand Dispatch 2030



#### 4.4. BASE CASE & HRE SCENARIO COMPARISON

The following table gives some Key Performance Indicators for the Base Case and the HRE plan:

Scenario	Key Performance Indicators								
	2030 planting	Retirements	Renewable energy share	Dispatch	Operability and renewable penetration	Fuel and emissions for 2030	Total system cost 2030	Generation cost 2030	Total Cost 2020-2030
<b>Base Case</b>	ICES: 289 MW ST: 50 MW OCGT: 144 MW CCGT: 4 000 MW Hydro: 595 MW Solar PV: 2 180 MW CSP: 50 MW Wind: 1 016 MW BioGas: 7 MW BESS: 201 MW/213 MWh PHS: 49 MW/197 MWh	Zouk and Jieh ST in 2024	32%	Fulfills minimum kinetic energy requirements for dynamic stability	Negligible renewable energy curtailment (<1%)	Fuel Oil: 37 TJ Gas Oil: 4 TJ NG: 128 497 TJ CO2 emission: 7.18 Mt CO2 intensity: 263 g/kWh	74.26 \$/MWh	40.11 \$/MWh	2020: 1 314 M\$ 2021: 1 402 M\$ 2022: 2 135 M\$ 2023: 2 074 M\$ 2024: 1 817 M\$ 2025: 1 621 M\$ 2026: 1 696 M\$ 2027: 1 764 M\$ 2028: 1 873 M\$ 2029: 1 949 M\$ 2030: 2 027 M\$ Total: 19 672 M\$
<b>High Renewable Expansion</b>	ICES: 709 MW ST: 50 MW OCGT: 144 MW CCGT: 3 450 MW Hydro: 595 MW Solar PV: 3 230 MW CSP: 50 MW Wind: 656 MW BioGas: 7 MW BESS: 246 MW/246 MWh PHS: 49 MW/197 MWh	Zouk and Jieh ST in 2024	35%	Fulfills minimum kinetic energy requirements for dynamic stability	Acceptable renewable energy curtailment (~2%)	Fuel Oil: 99 TJ Gas Oil: 16 TJ NG: 125 003 TJ CO2 emission: 6.99 Mt CO2 intensity: 256 g/kWh	73.87 \$/MWh	38.89 \$/MWh	2020: 1 314 M\$ 2021: 1 402 M\$ 2022: 2 135 M\$ 2023: 2 079 M\$ 2024: 1 821 M\$ 2025: 1 642 M\$ 2026: 1 719 M\$ 2027: 1 783 M\$ 2028: 1 849 M\$ 2029: 1 926 M\$ 2030: 2 016 M\$ Total: 19 687 M\$

Table 19: Base Case vs HRE comparative table

Both scenarios meet the generation planning requirements and guarantee the dynamic stability of the system. The Base Case reaches 32% renewable in 2030 while the High Renewable Expansion scenario reaches 35%. The total system costs (\$/MWh) are quite similar with a slight advantage for the HRE scenario in 2030. The total cost (investment, retirement, O&M and fuel costs) of the trajectory between 2020 and 2030 is of the same order (~20 B\$).



## 5. CONCLUSIONS

This study report has presented a 10 year Least Cost generation plan (2020-2030) for the Lebanese electricity generation system. Two scenarios, the first serving as a reference called "Base Case" and the second "High Renewable Expansion" (HRE) allowing for higher RE integration, were explored in detail. The HRE scenario has been identified through a sensitivity analysis, presented in this report, as being the most optimal, ambitious and feasible scenario. However, these plans are some of many the country could end up following. No matter which plan is chosen, a decision must be made in a very short time to allow action on initial, urgently needed investments. In any case, the chosen plan will need to be continually updated to reflect the changing conditions of the country and the electricity sector.

The Base Case generation plan will ramp up the total capacity to 8 331 MW, by 2030, including 4 483 MW of thermal, 595 MW of RoR hydro, 50 MW of CSP, 2 180 MW of solar PV and 1 016 MW of wind. Under this plan, the generation mix will transition from Fuel Oil to Natural Gas and RE penetration will increase from 4% in 2020 to 32% in 2030.

The HRE, generation plan will ramp up the total capacity to 8 952 MW, by 2030, 4 415 MW of thermal, 595 MW of RoR hydro, 50 MW of CSP, 3 230 MW of solar PV and 656 MW of wind. Under this plan, the generation mix will transition from Fuel Oil to Natural Gas and RE penetration will increase from 4% in 2020 to 35% in 2030.

The HRE scenario is based on three main thermal generation sites, integrates a high amount of utility scale PV & wind turbines and decarbonizes densely populated areas (Zouk and Jieh) while taking advantage of the already existing infrastructure to integrate storage thus reduce costs and risk of delays.

The urgent and no regrets actions that must be made to move forward on permanent solutions are:

- Heavy investments should be allocated for solar and wind even beyond the scenario annual limits if possible;
- The NG must be made available as main fuel as quick as possible in Deir Ammar and Zahrani, and afterwards in Selaata;
- Three additional CCGTs are necessary for the baseload generation. They are distributed over the sites provided as inputs to this study: Deir Ammar, Zahrani and Selaata.

Finally, the reader should keep in mind that the government has imposed additional constraint of a 21/24h supply by 2022 (tied to a potential tariff increase), thus tipping the scale towards short-notice deployment solutions (i.e. rentals) to quickly increase generation capacity. If the permanent generation developments were to be delayed then the extension of the rental solutions would become essential.

In order to mitigate the effect of the demand projection inaccuracy, this study suggests that the projections be reviewed and corrected further down the road. Once a considerable portion of the generation demand has been met, confidence in the assumptions can rise dramatically, thus painting a clearer way forward.





## 6. REFERENCES

- [1] "EIB Group Climate Bank Roadmap 2021-2025," ["https://www.eib.org/attachments/thematic/eib\\_group\\_climate\\_bank\\_roadmap\\_en.pdf"](https://www.eib.org/attachments/thematic/eib_group_climate_bank_roadmap_en.pdf)," November 2020.
- [2] "Guidance note on shadow price of carbon in economic analysis," ["http://pubdocs.worldbank.org/en/911381516303509498/2017-Shadow-Price-of-Carbon-Guidance-Note-FINAL-CLEARED.pdf"](http://pubdocs.worldbank.org/en/911381516303509498/2017-Shadow-Price-of-Carbon-Guidance-Note-FINAL-CLEARED.pdf)," World Bank, November 2017.



## 7. APPENDICES

### 7.1. VARIANTS

#### 7.1.1. WB CARBON PRICING SCENARIO

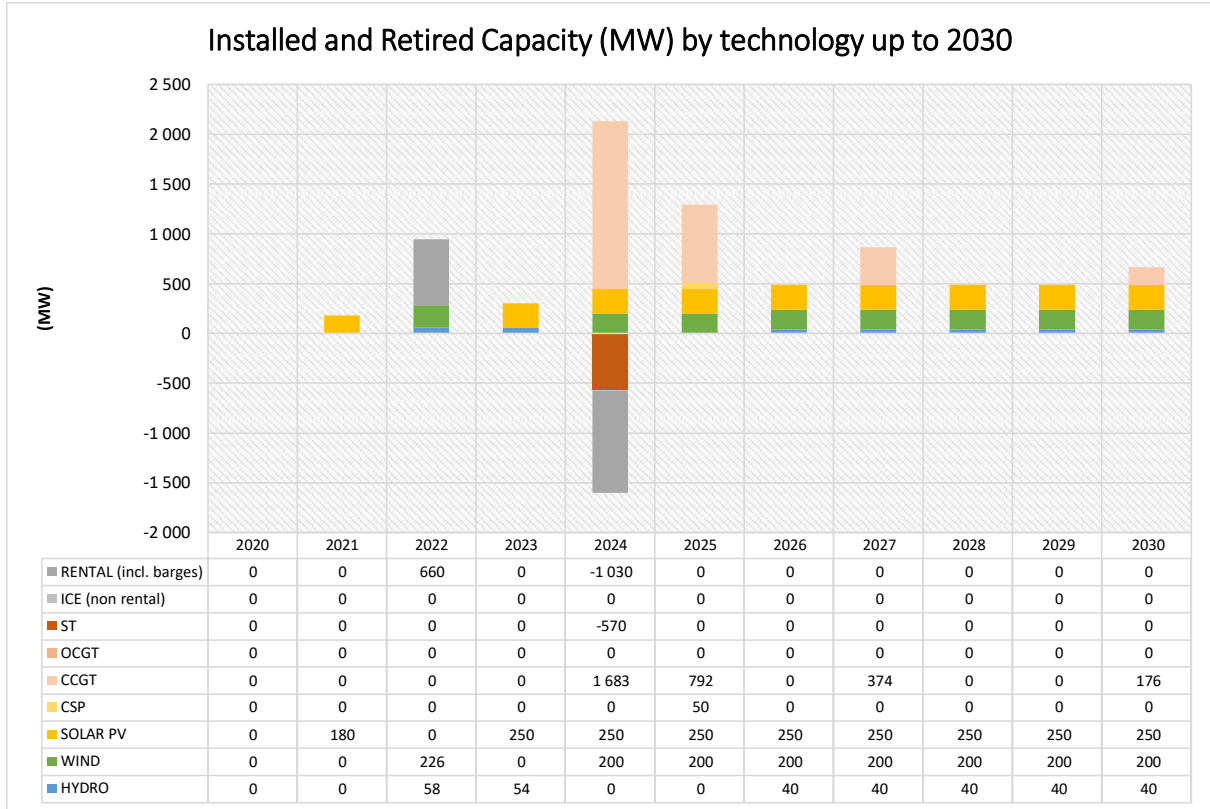


Figure 37: “WB Carbon Pricing” scenario - Installed and Retired Capacity

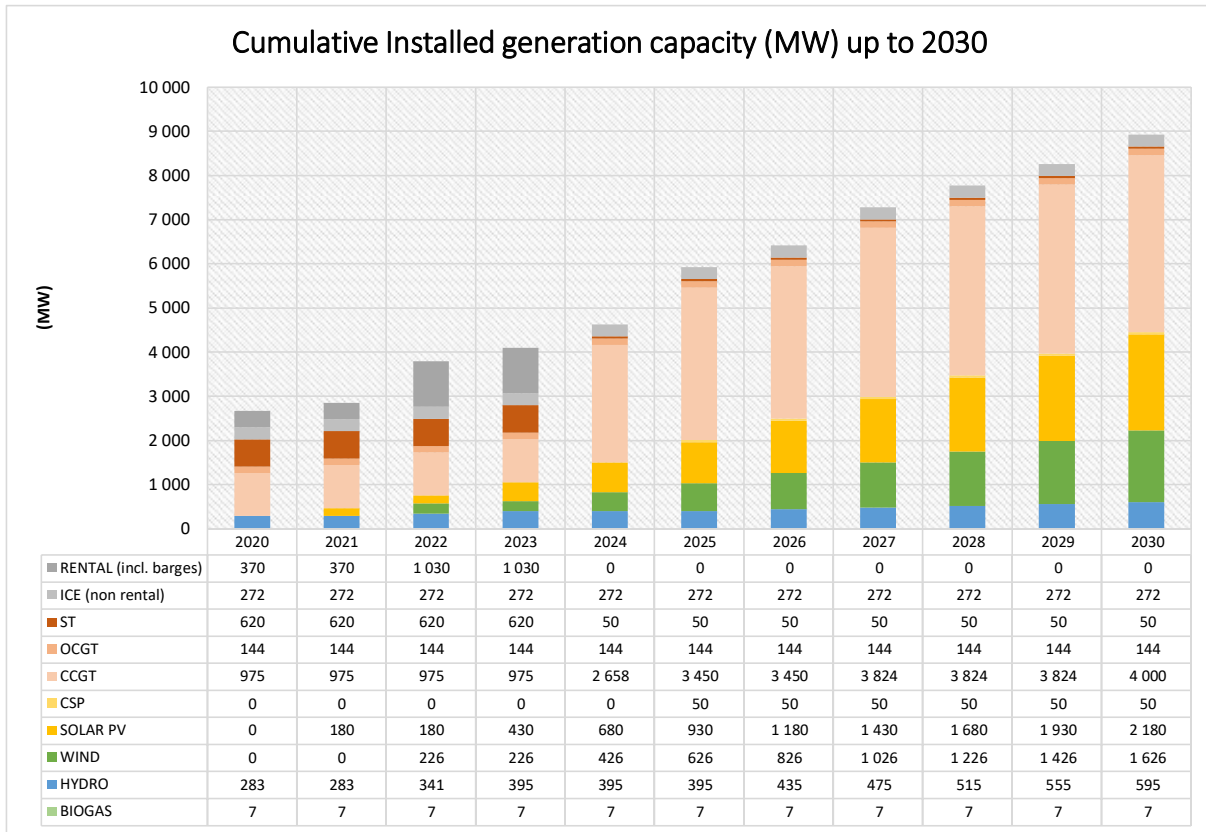


Figure 38: "WB Carbon Pricing" scenario - Cumulative Installed Generation Capacity

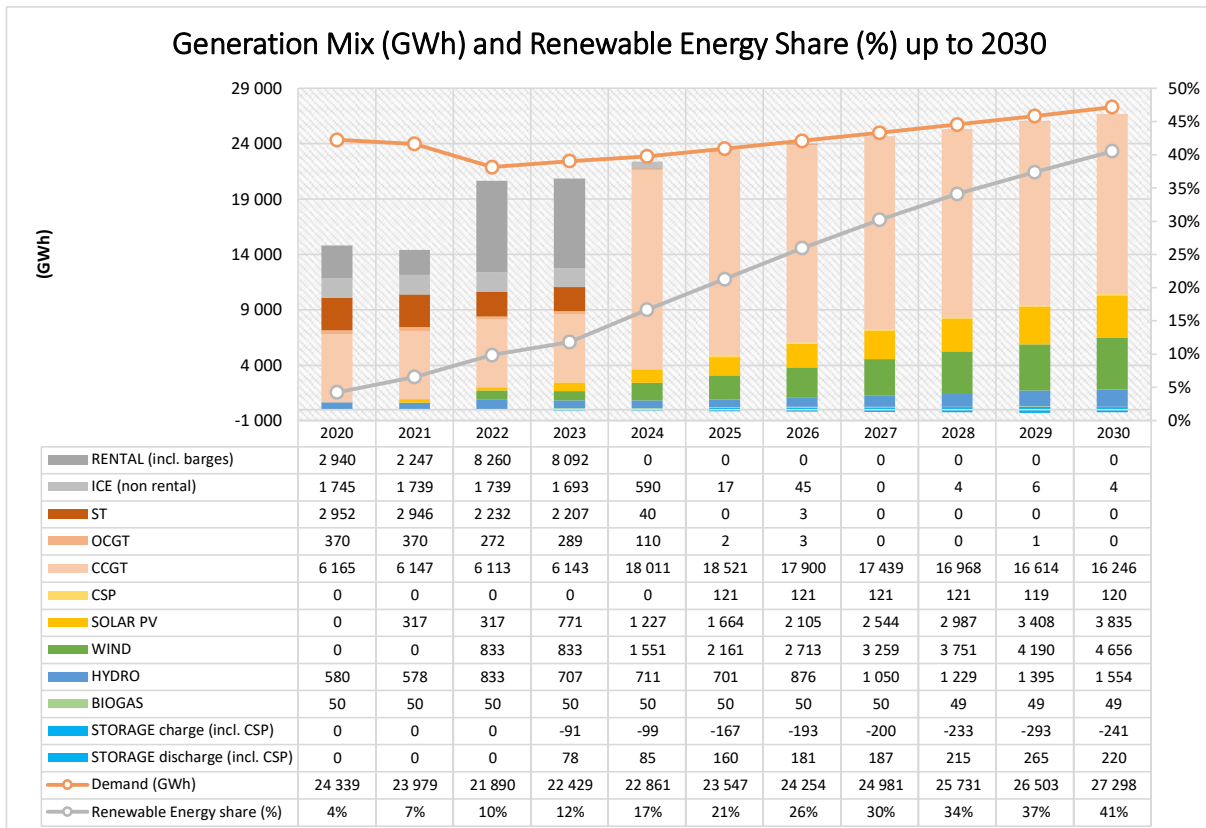


Figure 39: "WB Carbon Pricing" scenario - Generation Mix

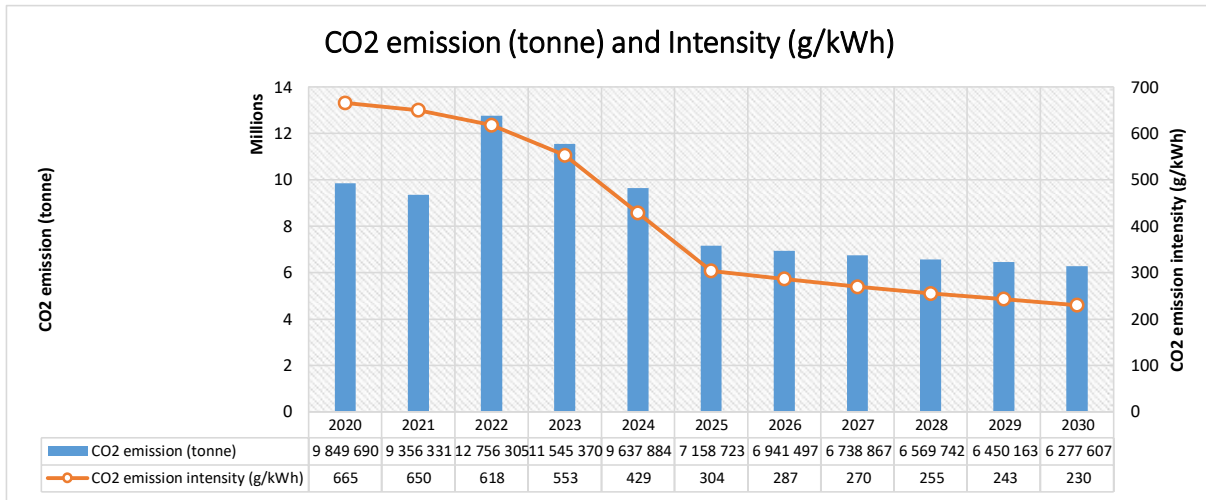


Figure 40: “WB Carbon Pricing” scenario - CO2 emission and intensity projection

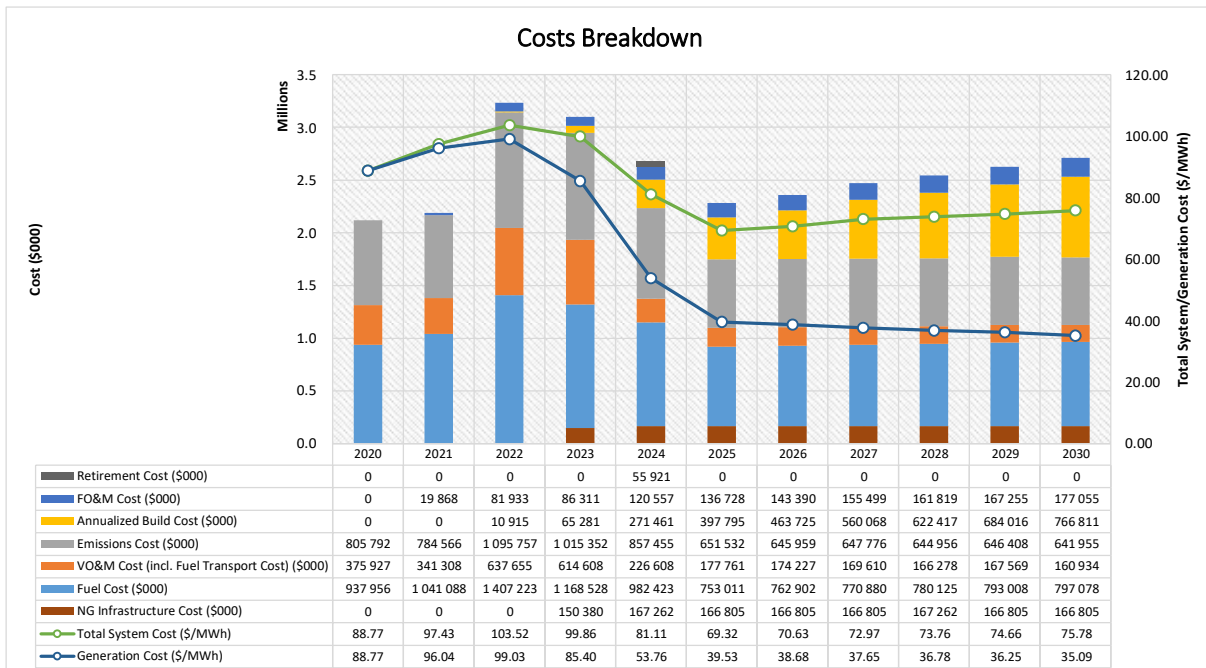


Figure 41: “WB Carbon Pricing” scenario - Costs Breakdown



Location/technology	Power plant available capacity (MW) Number of FSRU or pipeline	WB_SPC												
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030		
BINT JBEIL	N ICE FO				83	83								
JIB JANNINE	N ICE FO				83	83								
DEIR AMMAR	E CCGT RUNNING ON GO	490	490	490										
	E CCGT RUNNING ON NG				490	490	490	490	490	490	490	490	490	490
	N FSRU				1	1	1	1	1	1	1	1	1	1
	N CCGT 2x1 - E						561	825	825	825	825	825	825	825
	N CCGT 3x1 - E								561	1315	1315	1689	1689	1689
	<b>Total</b>	<b>490</b>	<b>490</b>	<b>994</b>	<b>994</b>	<b>1,051</b>	<b>1,315</b>	<b>1,315</b>	<b>1,689</b>	<b>1,689</b>	<b>1,689</b>	<b>1,689</b>	<b>1,685</b>	
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50	50	50	50	
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA						1	1	1	1	1	1	1	
	N CCGT 3x1 - E						561	825	825	825	825	825	825	
	<b>Total</b>						<b>561</b>	<b>825</b>	<b>825</b>	<b>825</b>	<b>825</b>	<b>825</b>	<b>825</b>	
ZOUK	E ICE BARGE	185	185											
	E ICE FO	194	194	194	194	194	194	194	194	194	194	194	194	
	E ST	380	380	380	380									
	<b>Total</b>	<b>759</b>	<b>759</b>	<b>574</b>	<b>574</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	<b>194</b>	
ZAHRANI	E CCGT RUNNING ON GO	485	485	485										
	E CCGT RUNNING ON NG				485	485	485	485	485	485	485	485	485	
	N RENTAL ICE			252	252									
	N FSRU				1	1	1	1	1	1	1	1	1	
	N CCGT 3x1 - E						561	825	825	825	825	825	825	
	<b>Total</b>	<b>485</b>	<b>485</b>	<b>737</b>	<b>737</b>	<b>1,046</b>	<b>1,310</b>	<b>1,310</b>	<b>1,310</b>	<b>1,310</b>	<b>1,310</b>	<b>1,310</b>		
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74	74	74		
JIEH	E ICE BARGE	185	185											
	E ICE FO	78	78	78	78	78	78	78	78	78	78	78		
	E ST	190	190	190	190									
	N RENTAL ICE			108	108									
	<b>Total</b>	<b>453</b>	<b>453</b>	<b>376</b>	<b>376</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	<b>78</b>	
SOUR	E OCGT	70	70	70	70	70	70	70	70	70	70	70		
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21	21	21		
	LITANI	199	199	199	199	199	199	199	199	199	199	199		
	NAHR BARED	17	17	17	17	17	17	17	17	17	17	17		
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32	32	32		
	SAFA	13	13	13	13	13	13	13	13	13	13	13		
	DARAYA, CHAMRA, YAMOUNEH & BLAT			58	58	58	58	58	58	58	58	58		
	JANNEH			54	54	54	54	54	54	54	54	54		
	REMAP BALANCE							40	80	120	160	200		
	<b>Total</b>	<b>283</b>	<b>283</b>	<b>341</b>	<b>395</b>	<b>395</b>	<b>395</b>	<b>435</b>	<b>475</b>	<b>515</b>	<b>555</b>	<b>595</b>		
	SOLAR PV			180	180	430	680	930	1180	1430	1680	1930	2180	
DISTRIBUTED SOLAR PV	MEW TARGET OF 500 MW by 2030				63	126	185	248	311	374	437	500		
CSP	N_CSP_STORAGE_7.5H_CF_27_MAX_1187						50	50	50	50	50	50		
WIND				226	226	226	226	226	226	226	226	226		
BIOGAS	E_BIOGAS_NAAMEH	7	7	7	7	7	7	7	7	7	7			
Storage	BESS (MW/MWh)				250/250	250/250	250/250	250/250	250/250	250/250	250/250	250/250	349/349	
	N_JOUN_PHS_UPGRADE_49.3MW_4H						49	49	49	49	49	49		
	<b>Total (MW/MWh)</b>				<b>250/250</b>	<b>250/250</b>	<b>250/250</b>	<b>299/447</b>	<b>299/447</b>	<b>299/447</b>	<b>299/447</b>	<b>398/546</b>		

Table 20: "WB Carbon Pricing" scenario - Installed Capacity Schedule

### 7.1.2. EIB CARBON PRICING SCENARIO

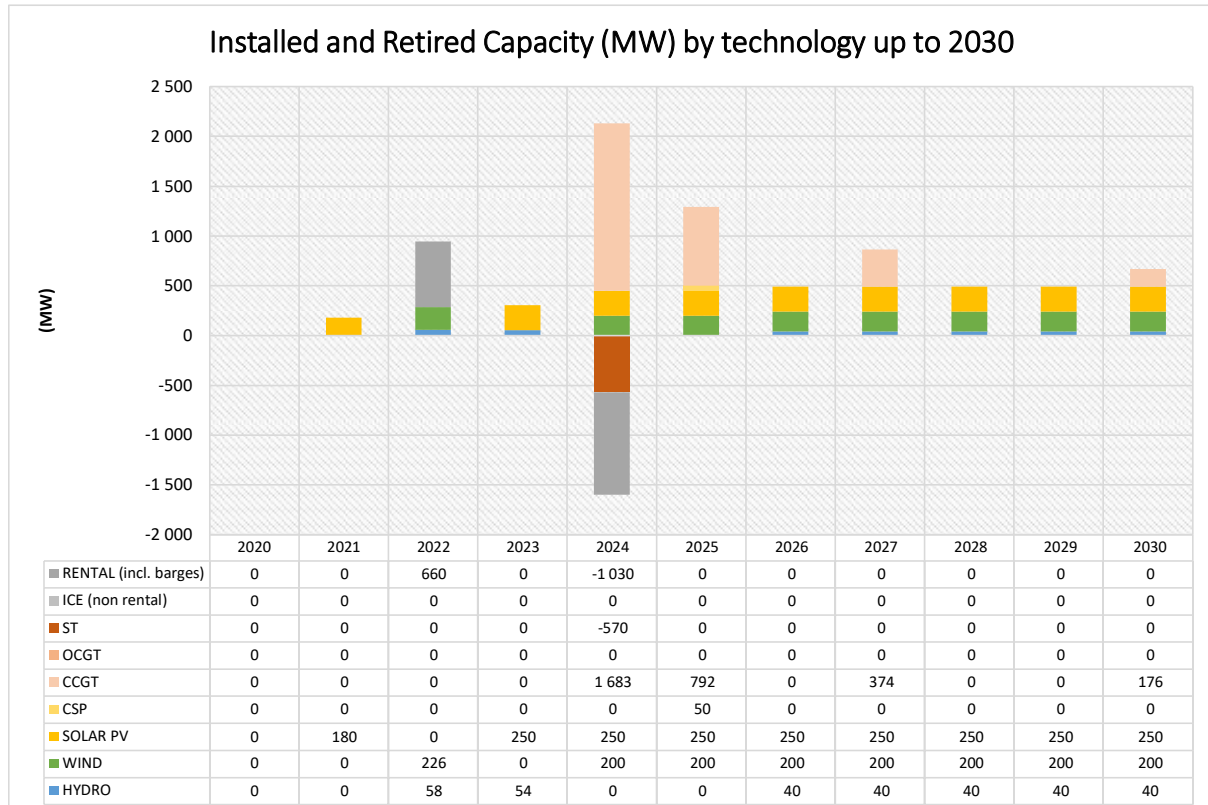




Figure 42: “EIB Carbon Pricing” scenario - Installed and Retired Capacity

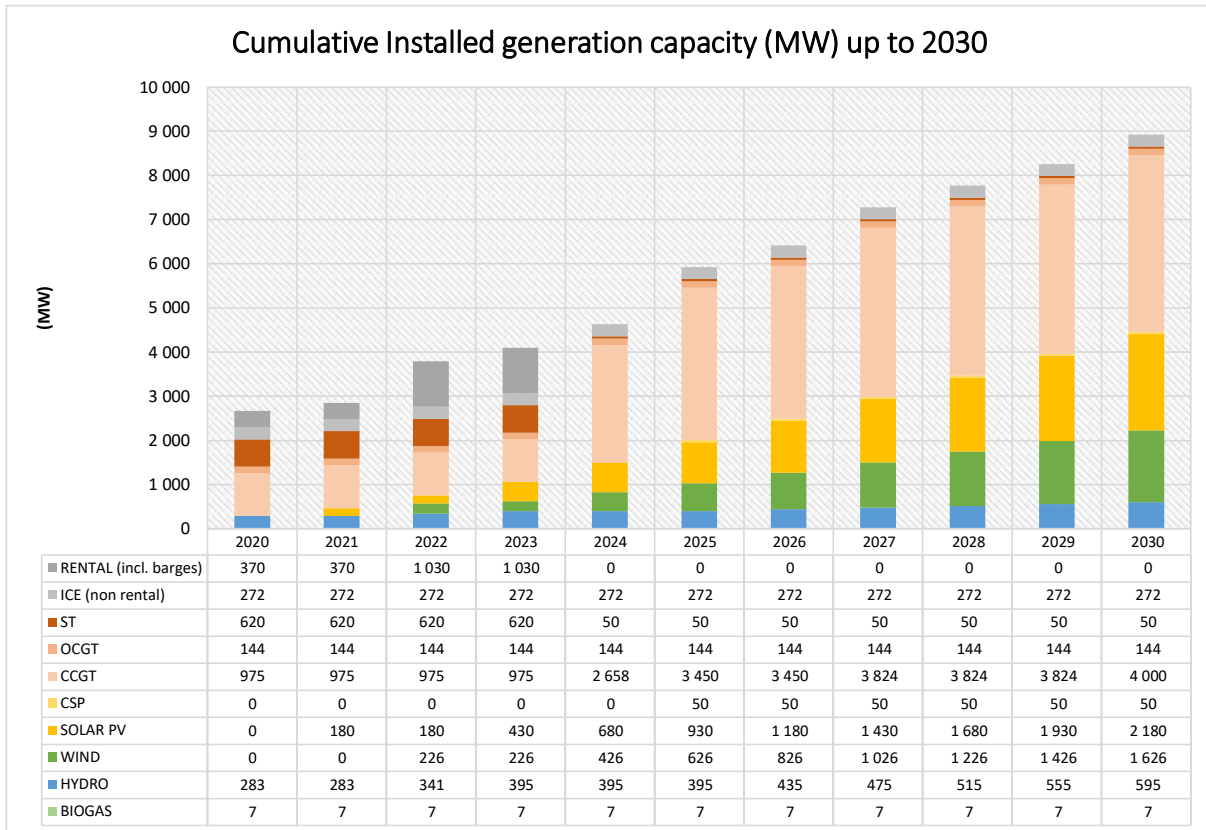


Figure 43: “EIB Carbon Pricing” scenario - Cumulative Installed Generation Capacity

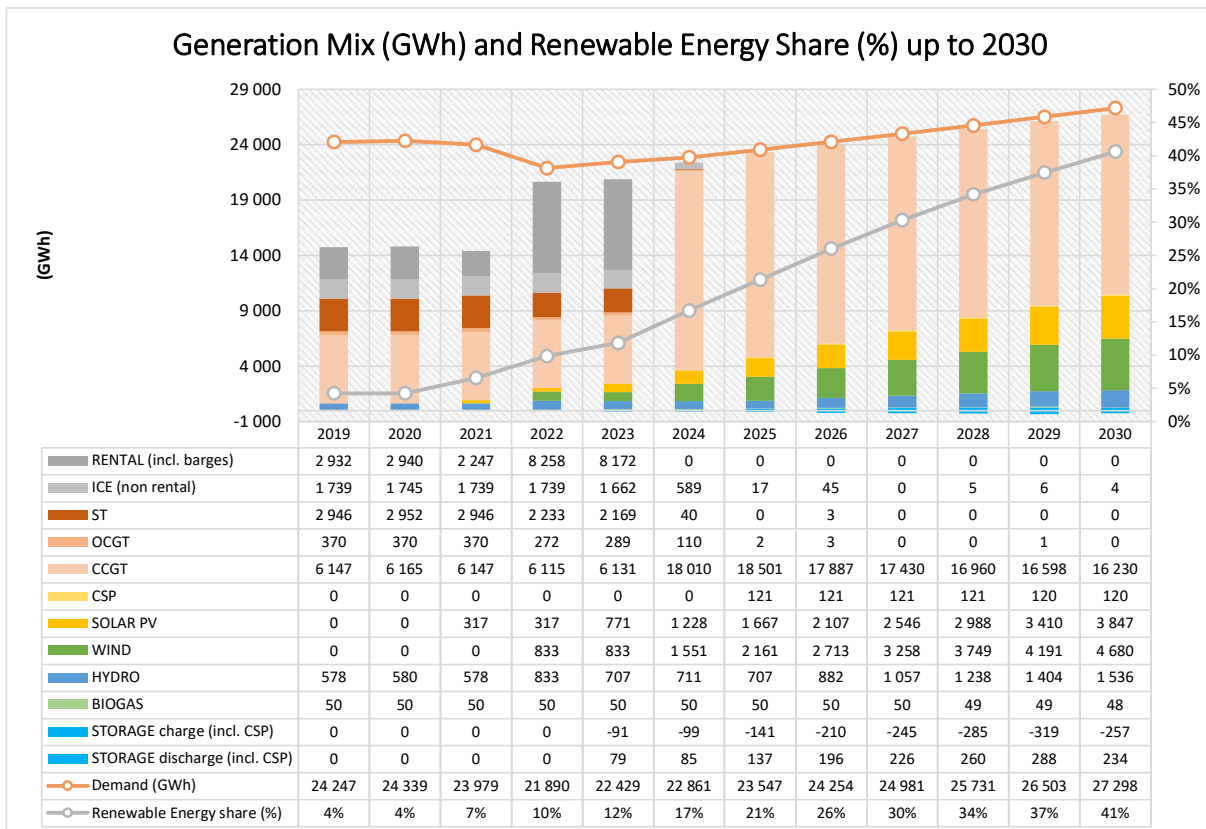


Figure 44: “EIB Carbon Pricing” scenario - Generation Mix

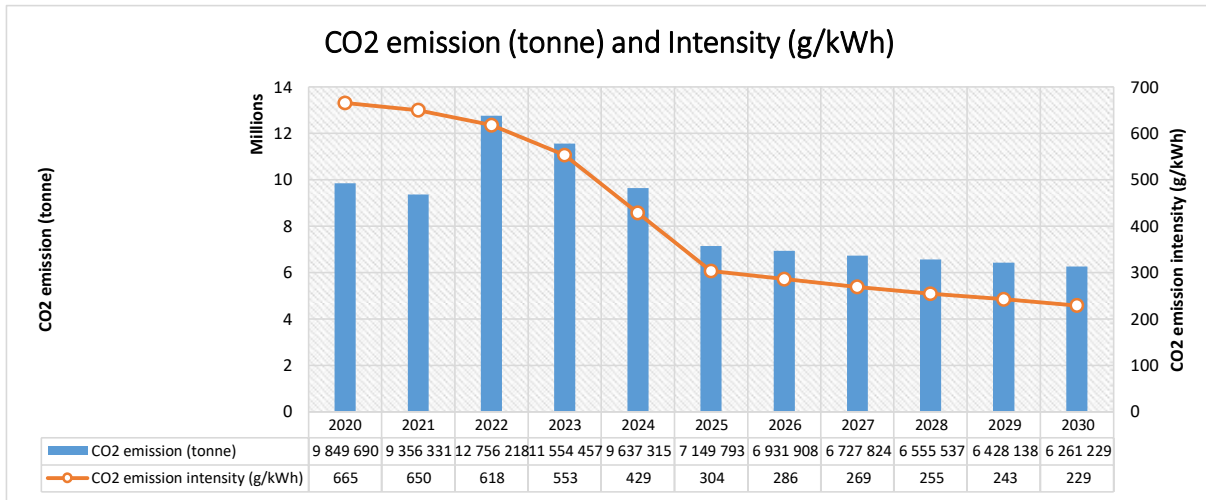


Figure 45: "EIB Carbon Pricing" scenario - CO2 emission and intensity projection

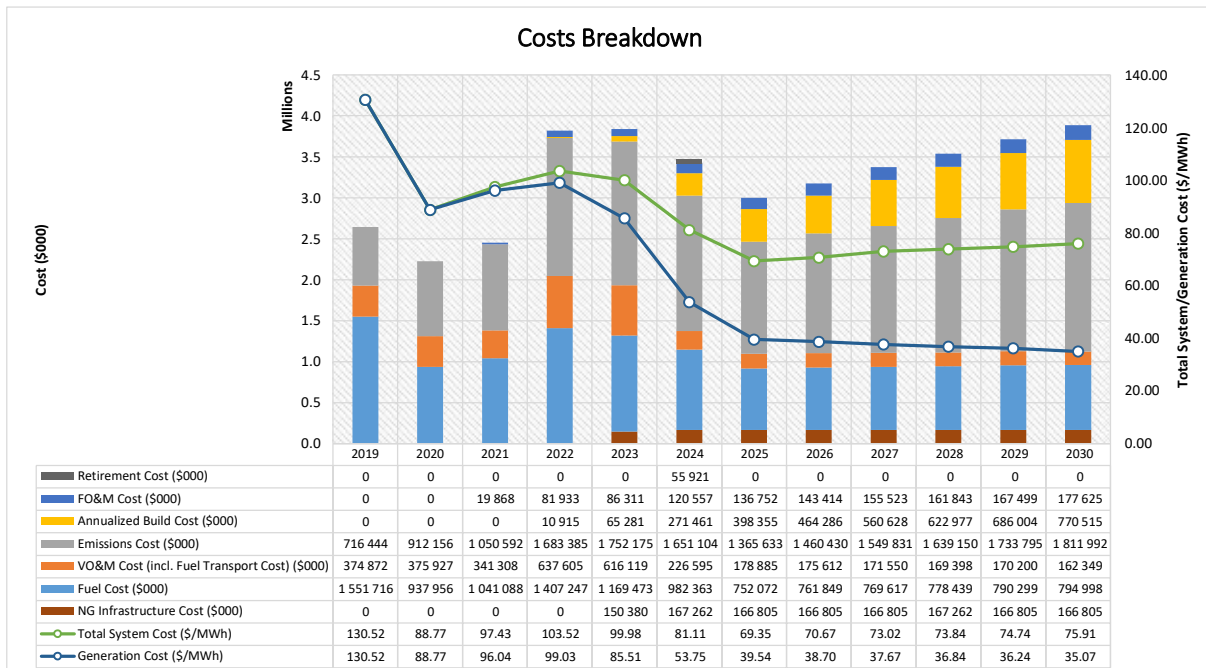


Figure 46: "EIB Carbon Pricing" scenario - Costs Breakdown



Location/technology	Power plant available capacity (MW) Number of FSRU or pipeline	EIB_SPC													
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030			
BINT JBEIL	N ICE FO				83	83									
JIB JANNINE	N ICE FO				83	83									
DEIR AMMAR	E CCGT RUNNING ON GO	490	490	490											
	E CCGT RUNNING ON NG				490	490									490
	N RENTAL ICE				504	504									
	N FSRU					1	1	1	1	1	1	1	1	1	1
	N CCGT 2x1 - E									374	374	374	374	374	550
	N CCGT 3x1 - E							561	825	825	825	825	825	825	825
	<b>Total</b>	490	490	994	994	1,051	1,315	1,315	1,315	1,689	1,689	1,689	1,689	1,689	1,865
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50	50	50	50	50	50
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA							1	1	1	1	1	1	1	1
	N CCGT 3x1 - E							561	825	825	825	825	825	825	825
	<b>Total</b>							561	825	825	825	825	825	825	825
ZOUK	E ICE BARGE	185	185												
	E ICE FO	194	194	194	194	194	194	194	194	194	194	194	194	194	194
	E ST	380	380	380	380	380									
	<b>Total</b>	759	759	574	574	194	194	194	194	194	194	194	194	194	194
ZAHRANI	E CCGT RUNNING ON GO	485	485	485											
	E CCGT RUNNING ON NG				485	485									485
	N RENTAL ICE				252	252									
	N FSRU					1	1	1	1	1	1	1	1	1	1
	N CCGT 3x1 - E								561	825	825	825	825	825	825
	<b>Total</b>	485	485	737	737	1,046	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74	74	74	74	74	
JIEH	E ICE BARGE	185	185												
	E ICE FO	78	78	78	78	78	78	78	78	78	78	78	78	78	78
	E ST	190	190	190	190	190									
	N RENTAL ICE				108	108									
	<b>Total</b>	453	453	376	376	78	78	78	78	78	78	78	78	78	
SOUR	E OCGT	70	70	70	70	70	70	70	70	70	70	70	70	70	
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21	21	21	21	21	
	LITANI	199	199	199	199	199	199	199	199	199	199	199	199	199	
	NAHR BARED	17	17	17	17	17	17	17	17	17	17	17	17	17	
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32	32	32	32	32	
	SAFA	13	13	13	13	13	13	13	13	13	13	13	13	13	
	DARAYA, CHAMRA, YAMOUNEH & BLAT			58	58	58	58	58	58	58	58	58	58	58	
	JANNEH				54	54	54	54	54	54	54	54	54	54	
	REMAP BALANCE						40	80	120	160	200	200	200	200	
		<b>Total</b>	283	283	341	395	395	395	435	475	515	555	595		
SOLAR PV		180	180	430	680	930	1,180	1,430	1,680	1,930	2,180	2,180			
DISTRIBUTED SOLAR PV	MEW TARGET OF 500 MW by 2030				63	126	189	252	315	378	441	500			
CSP	N_CSP_STORAGE_7.5H_CF_27_MAX_1187						50	50	50	50	50	50			
WIND				226	226	426	626	826	1,026	1,226	1,426	1,626			
BIOGAS	E_BIOGAS_NAAMEH	7	7	7	7	7	7	7	7	7	7	7			
Storage	BESS (MW/MWh)				250/250	250/250	250/250	250/250	250/250	250/250	272/272	406/406			
	N_JOUN_PHS_UPGRADE_49.3MW_4H						49	49	49	49	49	49			
	<b>Total (MW/MWh)</b>				250/250	250/250	250/250	299/447	299/447	299/447	321/469	455/603			

Table 21: "EIB Carbon Pricing" scenario - Installed Capacity Schedule

### 7.1.3. LOW DEMAND GROWTH SCENARIO

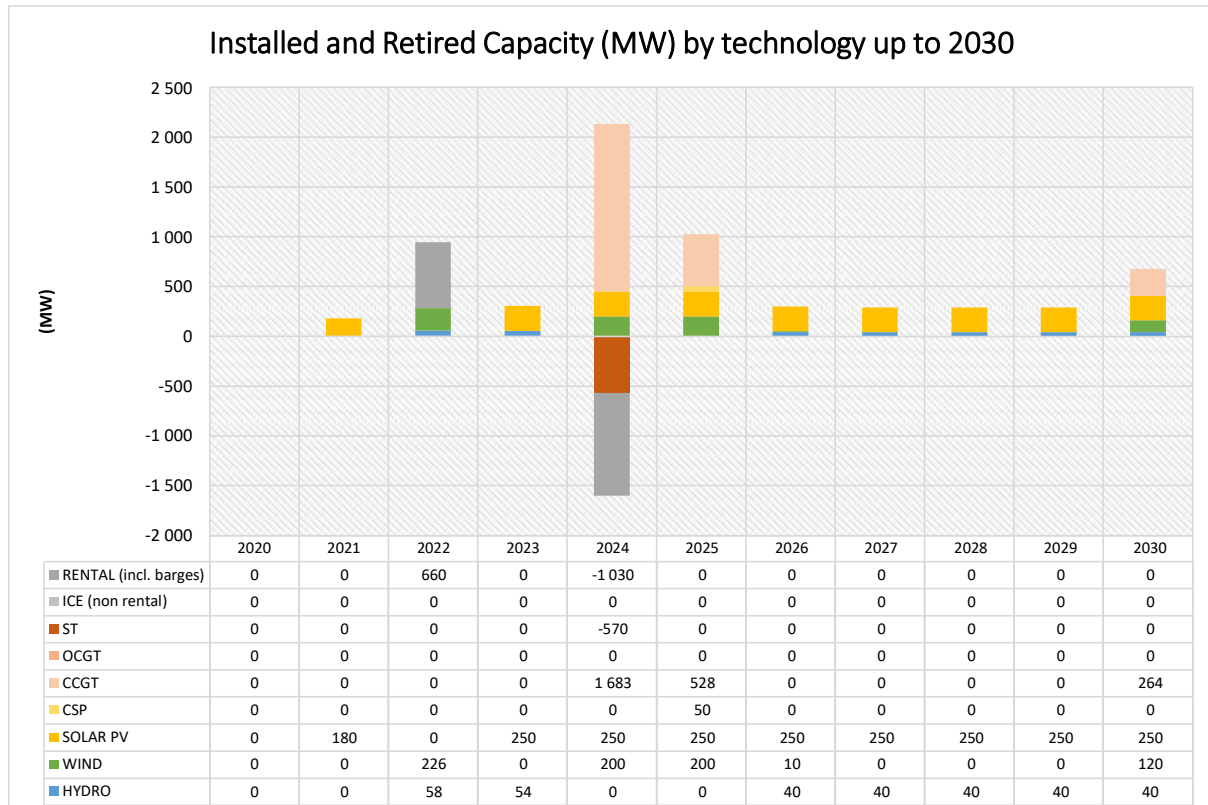






Figure 47: “Low Demand Growth” scenario - Installed and Retired Capacity

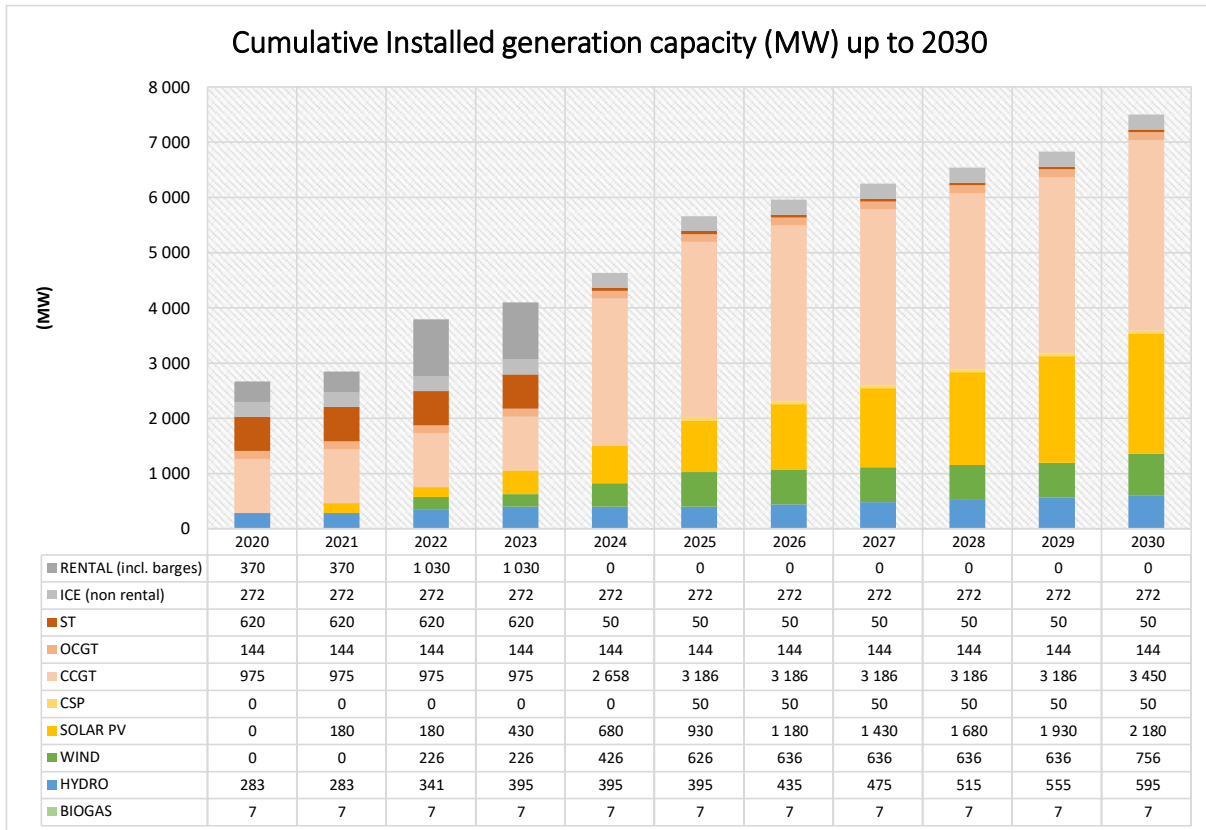


Figure 48: “Low Demand Growth” scenario - Cumulative Installed Generation Capacity

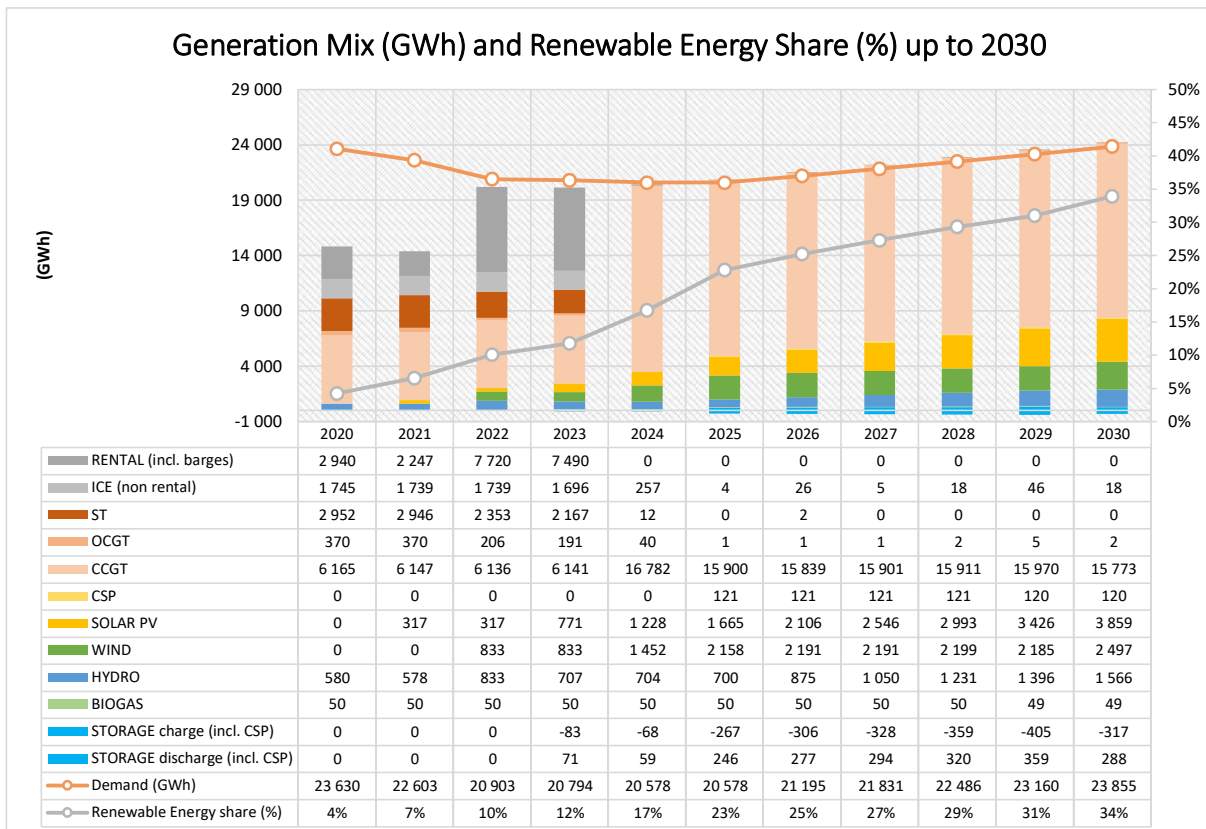


Figure 49: “Low Demand Growth” scenario - Generation Mix

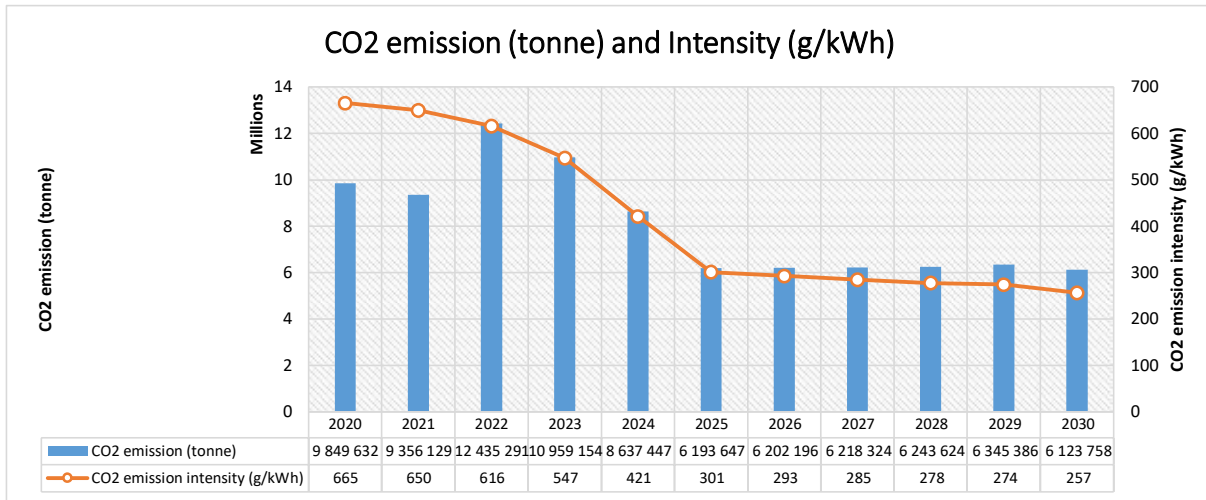


Figure 50: “Low Demand Growth” scenario - CO2 emission and intensity projection

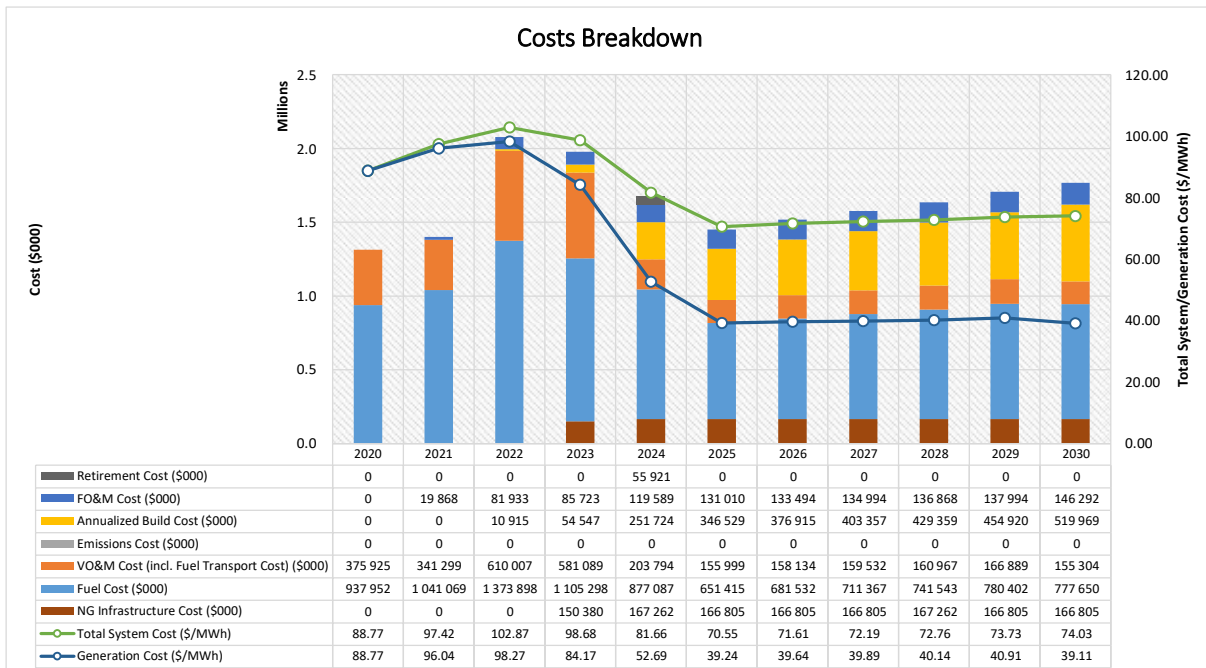


Figure 51: “Low Demand Growth” scenario - Costs Breakdown



Location/technology	Power plant available capacity (MW) Number of FSRU or pipeline	LOW DEMAND														
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030				
BINT JBEIL	N ICE FO				83	83										
JIB JANNINE	N ICE FO				83	83										
DEIR AMMAR	E CCGT RUNNING ON GO	490	490	490												
	E CCGT RUNNING ON NG				490	490										490
	N RENTAL ICE				504	504										
	N FSRU				1	1	1	1	1	1	1	1	1	1	1	1
	N CCGT 3x1 - E						561	561	561	561	561	561	561	561	561	561
	<b>Total</b>	490	490	994	994	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,315	
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA						1	1	1	1	1	1	1	1	1	
	N CCGT 3x1 - E						561	825	825	825	825	825	825	825	825	
	<b>Total</b>						561	825	825	825	825	825	825	825	825	
ZOUK	E ICE BARGE	185	185													
	E ICE FO	194	194	194	194	194										
	E ST	380	380	380	380											
	<b>Total</b>	759	759	574	574	194	194	194	194	194	194	194	194	194	194	
ZAHRANI	E CCGT RUNNING ON GO	485	485	485												
	E CCGT RUNNING ON NG				485	485	485	485	485	485	485	485	485	485	485	
	N RENTAL ICE				252	252										
	N FSRU				1	1	1	1	1	1	1	1	1	1	1	
	<b>Total</b>	485	485	737	737	1,046	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74	74	74	74	74	74	
JIEH	E ICE BARGE	185	185													
	E ICE FO	78	78	78	78	78										
	E ST	190	190	190	190											
	<b>Total</b>	453	453	376	376	78	78	78	78	78	78	78	78	78	78	
SOUR	E OCGT	70	70	70	70	70	70	70	70	70	70	70	70	70		
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21	21	21	21	21	21	
	LITANI	199	199	199	199	199	199	199	199	199	199	199	199	199	199	
	NAHR BARED	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32	32	32	32	32	32	
	SAFA	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
	DARAYA, CHAMRA, YAMOUNEH & BLAT			58	58	58	58	58	58	58	58	58	58	58	58	
	JANNEH			54	54	54	54	54	54	54	54	54	54	54	54	
	REMAP BALANCE							40	80	120	160	200	200	200	200	
	<b>Total</b>	283	283	341	395	395	395	435	475	515	555	595	595	595		
SOLAR PV			180	180	430	680	930	1,180	1,430	1,680	1,930	2,180	2,180			
CSP	N CSP STORAGE 7.5H CF 27 MAX 1187							50	50	50	50	50	50			
WIND				226	226	426	626	636	636	636	636	636	756			
BIOGAS	E BIOGAS_NAAMEH	7	7	7	7	7	7	7	7	7	7	7	7			
Storage	BESS (MW/MWh)				229/229	229/229	229/229	229/229	229/229	229/229	229/229	229/229	229/229			
	N JOUN_PHS_UPGRADE_49.3MW_4H							49	49	49	49	49	49			
	<b>Total (MW/MWh)</b>				229/229	229/229	229/229	278/426	278/426	278/426	278/426	278/426				

Table 22: "Low Demand Growth" scenario - Installed Capacity Schedule

#### 7.1.4. PROGRESSIVE THERMAL INVESTMENTS SCENARIO

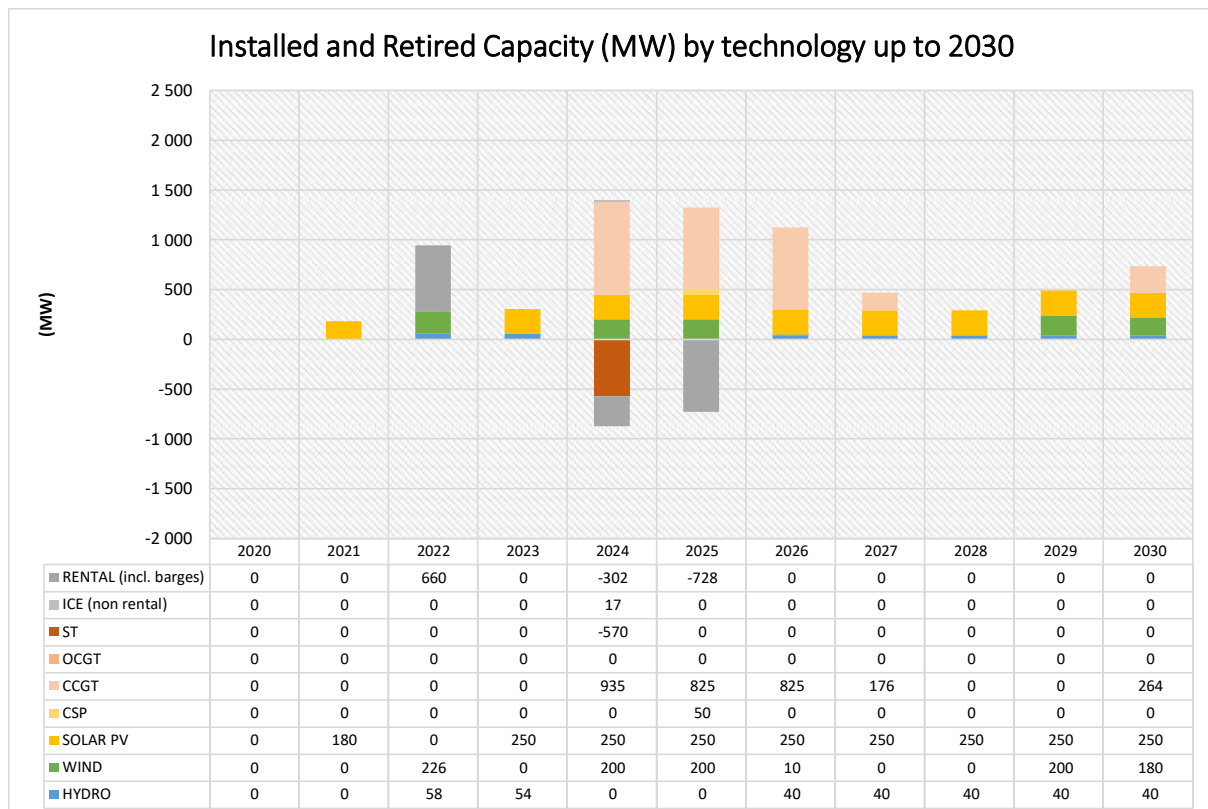


Figure 52: "Progressive Thermal Investments" scenario - Installed and Retired Capacity

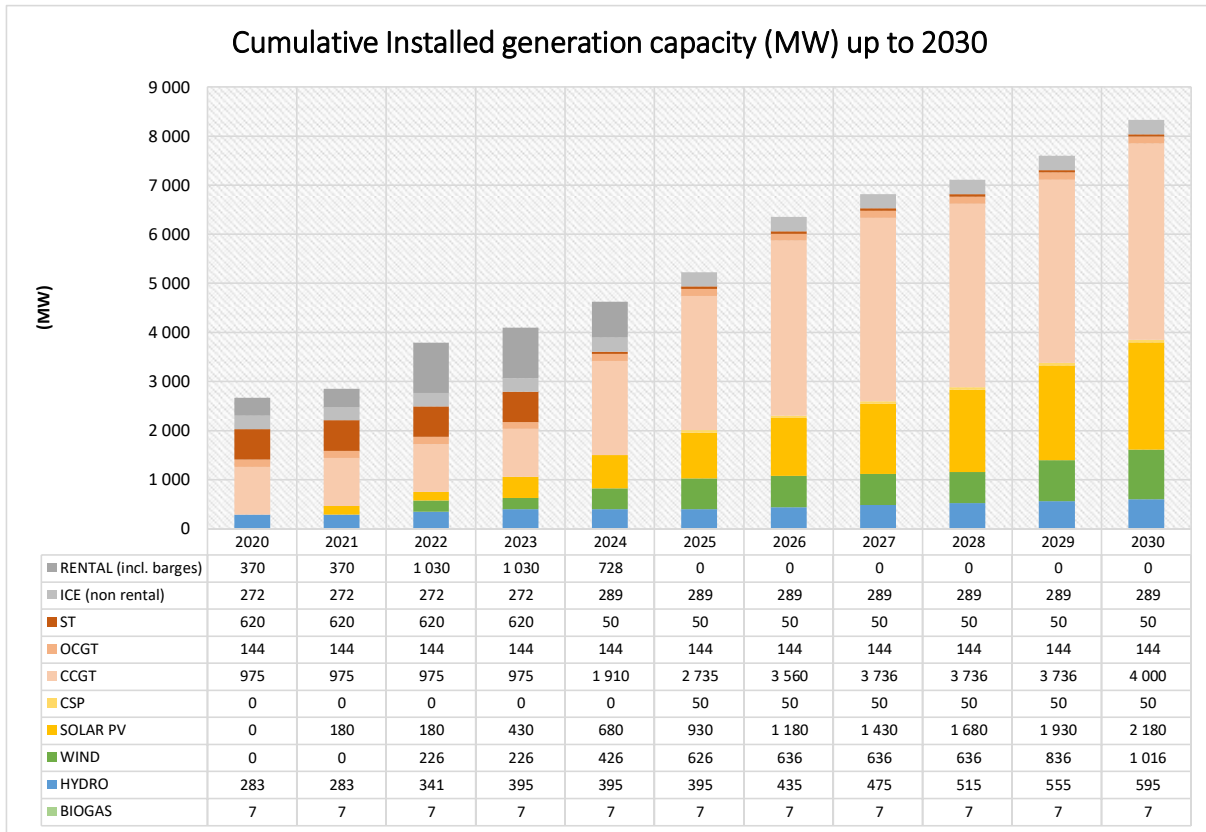


Figure 53: “Progressive Thermal Investments” scenario - Cumulative Installed Generation Capacity

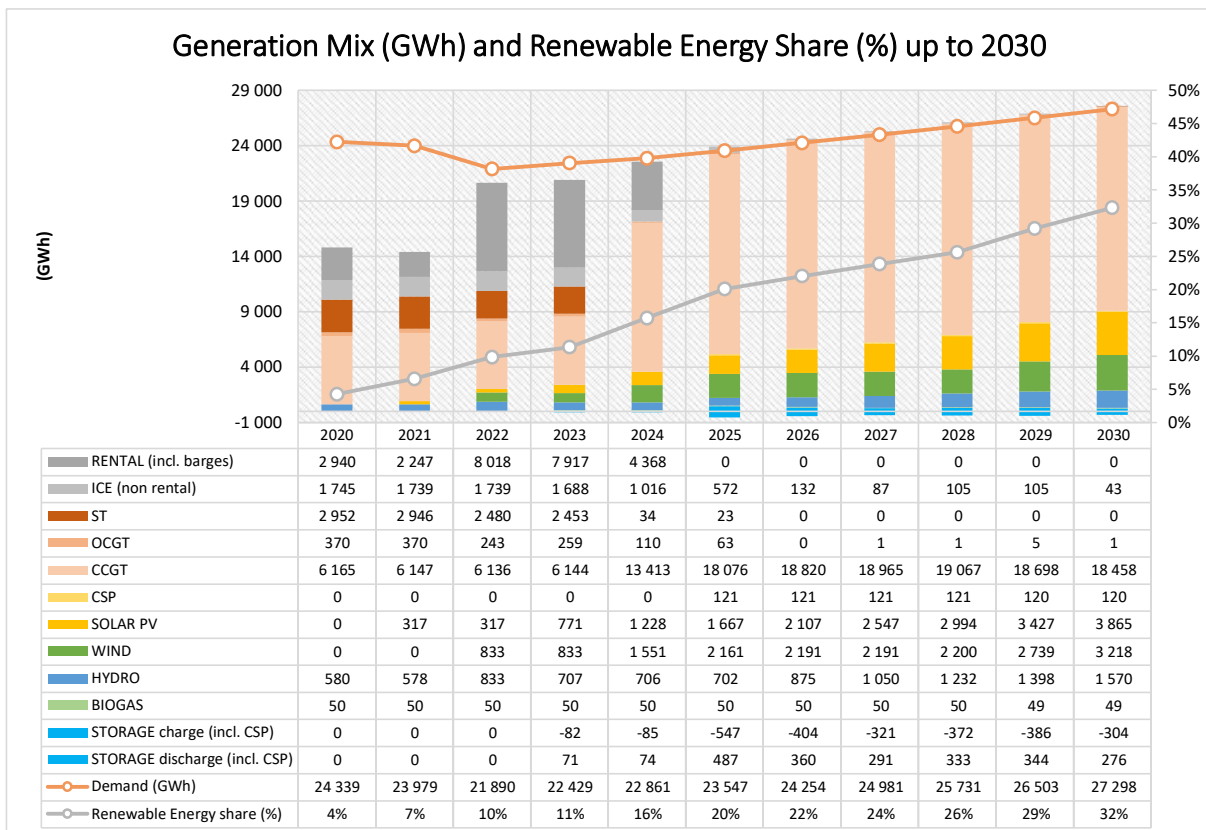


Figure 54: “Progressive Thermal Investments” scenario - Generation Mix

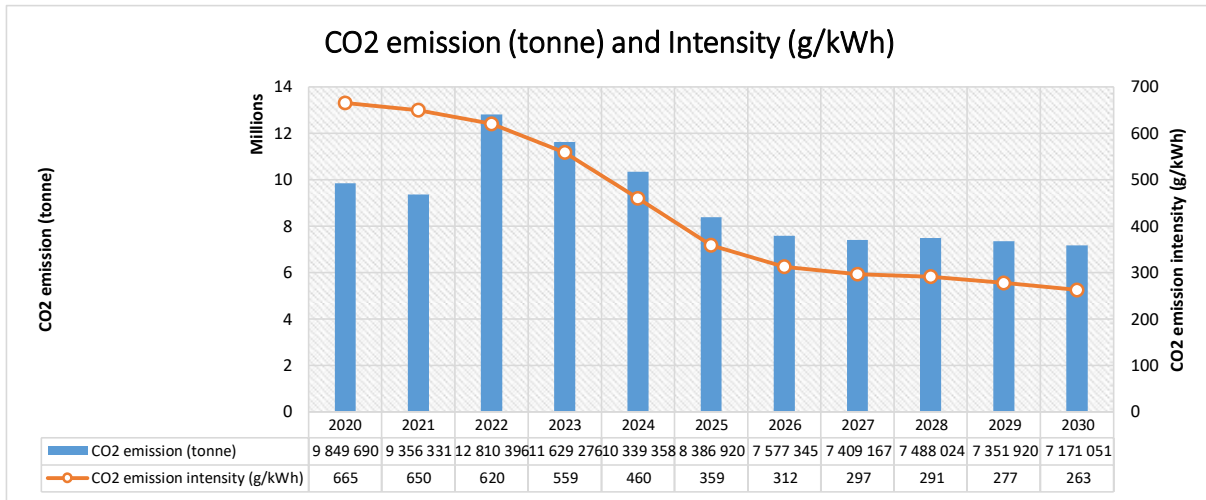


Figure 55: "Progressive Thermal Investments" scenario - CO2 emission and intensity projection

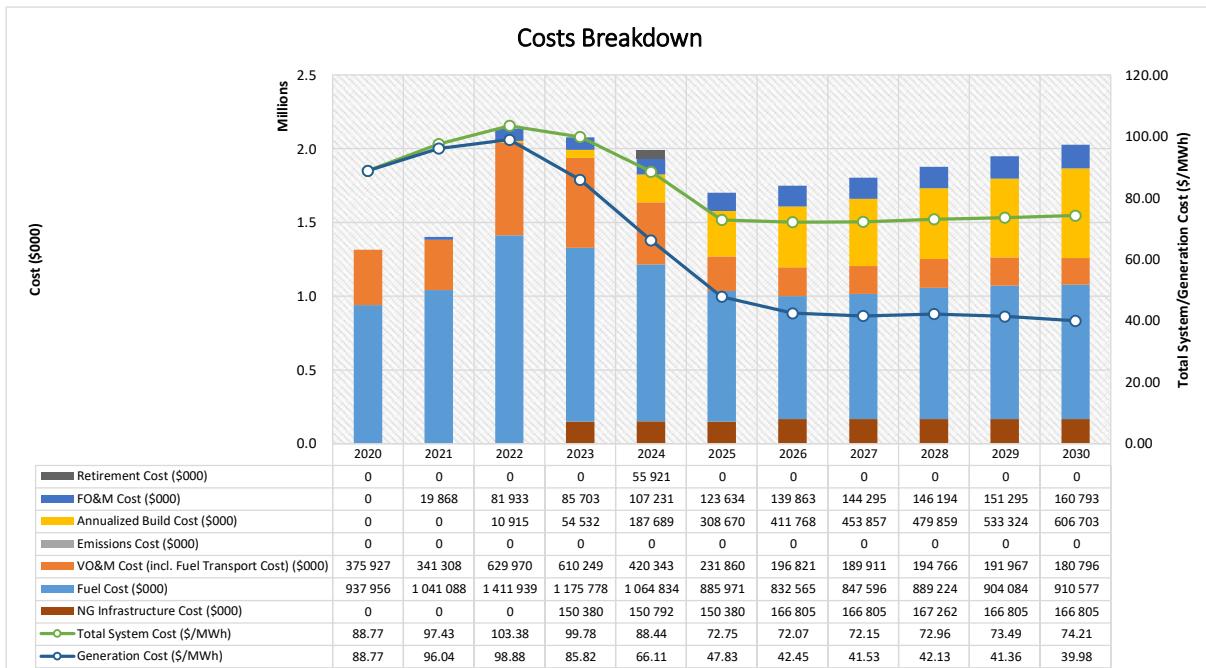


Figure 56: "Progressive Thermal Investments" scenario - Costs Breakdown



Location/technologie	Power plant available capacity (MW) Number of FSRU or pipeline	Progressive Thermal Investments														
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030				
BINT JBEIL	N ICE FO				83	83	83									
JIB JANNINE	N ICE FO				83	83	33									
DEIR AMMAR	E CCGT RUNNING ON GO	490	490	490												
	E CCGT RUNNING ON NG				490	490	490	490	490	490	490	490	490	490	490	490
	N RENTAL ICE				504	504	504									
	N FSRU				1	1	1	1	1	1	1	1	1	1	1	1
	N CCGT 2x1 - E					374	374	374	374	374	374	374	374	374	374	374
	N CCGT 3x1 - E							561	561	561	561	561	561	561	561	561
	<b>Total</b>	490	490	994	994	1 368	1 425	1 425	1 425	1 425	1 425	1 425	1 425	1 425	1 425	1 425
HRAYCHE	E ST	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
SELAATA	N PIPELINE DEIR AMMAR TO SELAATA									1	1	1	1	1	1	1
	N CCGT 3x1 - E									825	825	825	825	825	825	825
	<b>Total</b>									825	825	825	825	825	825	825
ZOUK	E ICE BARGE	185	185													
	E ICE FO	194	194	194	194	194	194	194	194	194	194	194	194	194	194	194
	E ST	380	380	380	380	380										
	<b>Total</b>	759	759	574	574	194	194	194	194	194	194	194	194	194	194	194
ZAHRANI	E CCGT RUNNING ON GO	485	485	485												
	E CCGT RUNNING ON NG				485	485	485	485	485	485	485	485	485	485	485	485
	N RENTAL ICE				252	252										
	N FSRU				1	1	1	1	1	1	1	1	1	1	1	1
	N ICE DFNG					17	17	17	17	17	17	17	17	17	17	17
	N CCGT 3x1 - E						561	825	825	825	825	825	825	825	825	825
	<b>Total</b>	485	485	737	737	1 063	1 327	1 327	1 327	1 327	1 327	1 327	1 327	1 327	1 327	1 327
BAALBACK	E OCGT	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
JIEH	E ICE BARGE	185	185													
	E ICE FO	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
	E ST	190	190	190	190	190										
	N RENTAL ICE				108	108	108									
	<b>Total</b>	453	453	376	376	186	78	78	78	78	78	78	78	78	78	78
SOUR	E OCGT	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
HYDRO	KADISHA	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
	LITANI	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199
	NAHR BARED	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	NAHR IBRAHIM	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
	SAFA	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	DARAYA, CHAMIRA, YAMOUNEH & BLAT			58	58	58	58	58	58	58	58	58	58	58	58	58
	JANNEH			54	54	54	54	54	54	54	54	54	54	54	54	54
	REMAP BALANCE							40	80	120	160	200	240	280	320	360
	<b>Total</b>	283	283	341	395	395	395	435	475	515	555	595	635	675	715	755
SOLAR PV			180	180	430	680	930	1 180	1 430	1 680	1 930	2 180	2 430	2 680	2 930	3 180
CSP	N CSP STORAGE 7.5H CF 27 MAX 1187							50	50	50	50	50	50	50	50	50
WIND				226	226	426	626	636	636	636	636	636	636	636	636	636
BIOGAS	E BIOGAS NAAMEH	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Storage	BESS (MW/MWh)				227/230	227/230	227/230	227/230	227/230	227/230	227/230	227/230	227/230	227/230	227/230	227/230
	N JOUN PHS UPGRADE 49.3MW 4H							49	49	49	49	49	49	49	49	49
	<b>Total (MW/MWh)</b>				227/230	227/230	227/230	276/427	276/427	276/427	276/427	276/427	276/427	276/427	276/427	276/427

Table 23: "Progressive Thermal Investments" scenario - Installed Capacity Schedule



## 7.2. PROBLEM FORMULATION (LONG-TERM EXPANSION PLANNING)

Ref. energyexemplar.com

Long-term (LT) Capacity Expansion determines optimal investment decisions over long periods of time, usually up to 30 years. The PLEXOS LT-PLAN module accomplishes this by minimizing the Net Present Value of forward-looking investment costs and the generation cost. Therefore, the portfolio cost minimization problem is expanded to include the investment cost and the investment-related constraints as follows:

Minimize (Generation Cost + Investment Cost) subject to

- operation constraints
- and investment Constraints.

Here, Investment Cost may include costs of: new generator builds, transmission expansion, and/or generator retirements. The Investment Constraints may include regional capacity reserve margins, resource addition and retirement candidates (i.e. maximum units built / retired), technical and financial life spans, technology / fuel mix rules, Renewable Portfolio Standard (RPS), etc. The build and retirement candidates might include thermal, geothermal, wind or solar generators, transaction and demand side participation, transmission augmentations, or generator retrofits.

This optimization problem is formulated in PLEXOS as a Mixed Integer Linear Program. The following **simplified formulation aims to illustrate the minimization problem:**

$$\text{Minimize: } \sum_y (BuildCost_g * GenBuild_{g,y} + RetireCost_g * GenRetire_{g,y}) + (1 + D)^{-y} * \sum_{t \in y} \left[ \sum_g (SRMC_g * L_t * GenLoad_{g,t} + SPC_{g,t}) + VoLL * USE_t \right]$$

Minimize sum of net present value of build, retirement, generation costs, SPC, VoLL and etc.

With respect to:  $GenBuild_{g,y}$ ,  $GenRetire_{g,y}$ ,  $GenLoad_{g,t}$ ,  $USE_t$  and  $CapShort_y$

subject to:

- $\sum_g (P_{gmax} * Units_g) + \sum_y [(GenBuild_{g,y} - GenRetire_{g,y})P_{gmax} + CapShort_y] \geq PeakLoad_y + ReserveMargin_y \quad \forall y$ 

Capacity is sufficient to meet peak load plus required margin (incl. primary, secondary and tertiary reserve provision)
- $\sum_g GenLoad_{g,t} + USE_t = Demand_t \quad \forall t$ 

Energy demand is met
- $GenLoad_{g,t} \leq P_{gmax} * \left( Units_g + \sum_{i \leq y} GenBuild_{g,i} - GenRetire_{g,i} \right) \quad \forall g, t$ 

Dispatch is feasible
- $Kinetic\ Energy \geq Kinetic\ Energy_{min}$ 

Sufficient kinetic energy to cop with generation's N-1 event

where:



Variable / Parameter	Description	Type / Unit
$GenBuild_{g,y}$	Number of generating units built in year $y$ for Generator $g$	integer
$GenRetire_{g,y}$	Number of generating units retired in year $y$ for Generator $g$	integer
$GenLoad_{g,t}$	Dispatch level of generating unit $g$ in period $t$	MW, continuous
$SPC_t$	Shadow Price of Carbon emitted by generating unit $g$ in period $t$	\$/ton of CO <sub>2</sub>
$USE_t$	Unserved energy in dispatch period $t$	MWh, continuous
$CapShort_y$	Capacity shortfall in year $y$	MW, continuous
D	Discount rate	%
$L_t$	Number of hours in dispatch period $t$	hours
$BuildCost_g$	Build cost for generator $g$	\$
$RetireCost_g$	Cost of retirement for generator $g$	\$
$P_{max}$	Maximum generating capacity of generator $g$	MW
$Units_g$	Existing number of generating units $g$	integer
$PeakLoad_y$	Maximum power demand in year $y$	MW
$ReserveMargin_y$	Margin required over maximum power demand in year $y$ (incl. primary, secondary and tertiary reserve provisions)	MW
$CapShortPrice$	Capacity shortage price	\$/MW
$VoLL$	Value of lost load	\$/MWh
$SRMC_g$	Marginal cost of generation $g$	\$/MWh
$Demand_t$	Power demand in dispatch period $t$	MW