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Arab Petroleum Investments Corporation

MENA POWER INVESTMENT OUTLOOK 2020-2024

Between fighting a pandemic and managing renewables

December 2020

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Disclaimer

About APICORP

The Arab Petroleum Investments Corporation (APICORP) is a multilateral development financial institution established in 1975 by an international treaty between the ten Arab oil exporting countries. It aims to support and foster the development of the Arab world's energy sector and petroleum industries. APICORP makes equity investments and provides project finance, trade finance, advisory and research, and its headquarters is in Dammam, Kingdom of Saudi Arabia. APICORP is rated 'Aa2' with stable outlook by Moody's and 'AA' with a stable outlook by Fitch.

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I. The Impact of COVID-19 and Global Reset on the Power Markets

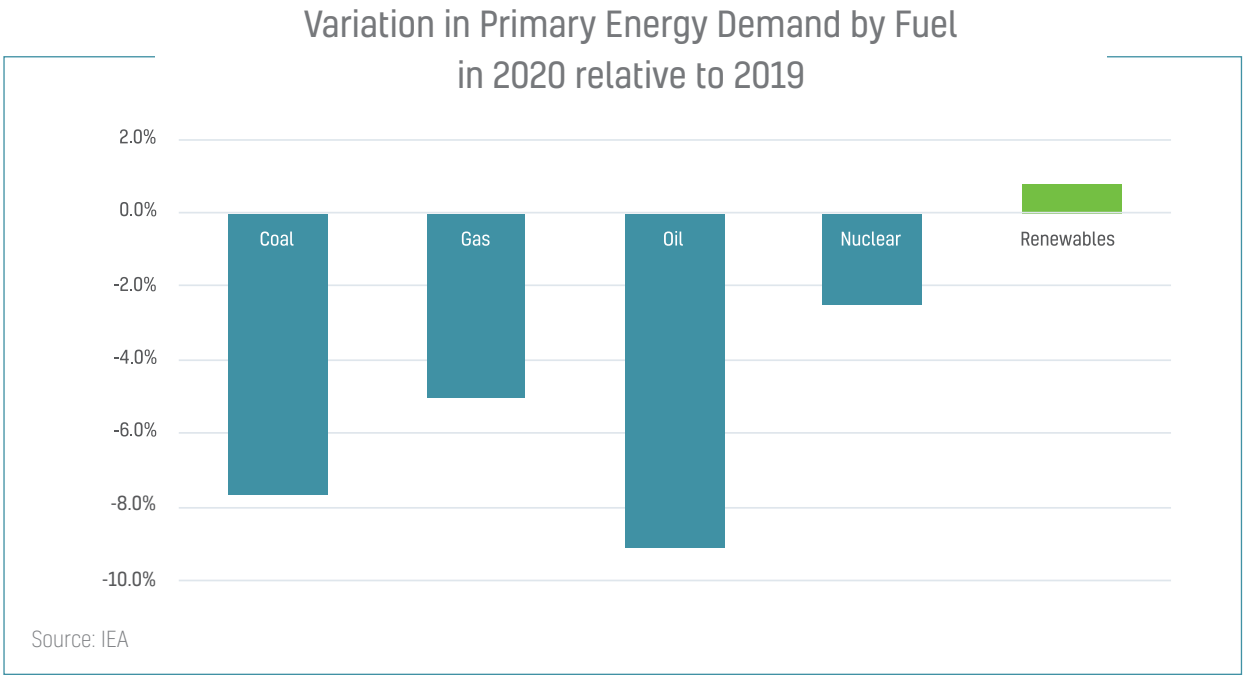
The unprecedented 2020 COVID-19 pandemic has impacted the world economy in a myriad of ways. Not since the Great Depression of the 1930s has the world experienced a "Global Reset" on such a widespread and synchronized scale. Costing the world economy a staggering USD 1 trillion[1], the repercussions of the crisis are being felt disproportionately and differently in various sectors, including the power sector.

During the pandemic, the needs for stable electricity supplies and digital services underscored the criticality of these two sectors in the economies. The USD 114 billion decline in the MENA power sector's planned investments compared to the 2019-2023 outlook was actually due to the commissioning of several projects during 2019 in Egypt, the UAE and Saudi Arabia. Hence, it is expected that when economies eventually start to recover, the power sector will play a vital role in accelerating the process[2]. How the future of demand and investments in the sector will look like will be largely determined by the power market structure, policy efficiency and the digitalization of the sector.

Impact on power demand and supply

A relatively small drop in electricity demand with a notable increase in residential share

The reduction in global electricity demand in 2020, estimated at 5%[3] compared to 2019, is also unprecedented. Globally, the International Energy Agency (IEA) estimates a 10% drop in investments – about USD 80 billion – in the power sector in 2020, including power generation, electricity networks and battery storage. Interestingly, the variation in primary energy demand by fuel in 2020 relative to 2019 demonstrated the resilience of renewables.



[1] COVID-19 pandemic and economic cost; impact on forcibly displaced people. Travel Medicine and Infectious Disease, Elsevier Volume 35, May-June 2020, 101661.

[2] More details on this in APICORP's White Paper "*Beyond Energy: How MENA Economies Emerge Post-2021*", November 2020.

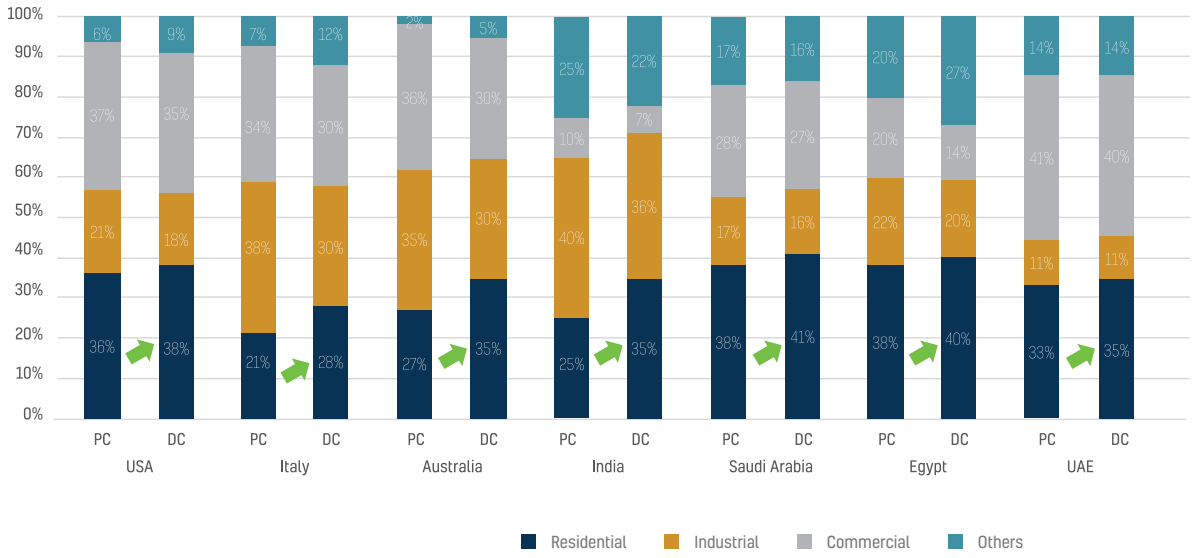
[3] Average drop in electricity demand in 2020 across the U.S., China, E.U., India and Rest of the World. The electricity generation mix as produced from hydrocarbons, nuclear and renewables - IEA.

Demand in power markets is concentrated in three major sectors: residential, commercial and industrial sectors. These sectors were affected in different ways due to the measures taken by governments to control the pandemic, including extended lockdowns, travel bans, social restrictions and work-from-home policies.

According to the IEA, electricity demand in 2020 dropped by 4.8% in the United States, 3% in China and 5.7% in India. European Union (EU) countries witnessed the steepest power demand drop at 8.2%.

The varying severity of the decline between countries can be attributed to the differences in the power market structures and consumption mix. The common pattern is that as industries and businesses reduced their operations due to lockdowns, people spent more time at home. This impacted national demand power profiles by increasing the share of the residential sector's electricity consumption and decreasing the share of the industrial and commercial sectors. Our analysis shows a similar pattern in MENA markets, as shown below:

Increase in residential power demand at expense of commercial and industrial power demand during Covid (DC-2020) vs. pre-Covid (PC-2020) for selected countries



Source: APICORP

Globally and in the MENA region, residential power demand increased at the expense of the commercial and industrial sectors. Hence, the overall power demand drop was mitigated to a certain degree in markets where the residential sector already constituted a large share in the power demand mix.

In the MENA region, the residential sector represents around 41% of the total power demand, followed by industrial sector (21%) and commercial sector (20%). The remaining 18% is comprised of other sectors such as agriculture and transport, as well as network losses (18%)[4].

The drop in total electricity demand in 2020 compared to 2019 was countered in many MENA countries by an increase in residential electricity demand due to the impact of COVID-19 and lower oil prices.

In Saudi Arabia, total electricity demand is expected to drop by 2.3% in 2020 compared to 2019, while the residential sector is expected to increase its share from 38% to 41% for the period. In Egypt, total electricity demand is expected to drop by 1.6%, while residential electricity demand is expected to increase by 2.1%. In the UAE, total electricity demand is expected to drop by 2% in 2020 compared to 2019, while residential electricity demand is expected to increase by 1.8%.

A welcome impact of stimulus measures

Several measures were taken by MENA governments during 2020 to reduce the financial and economic impact of COVID-19 and to support businesses and individuals. Among the stimulus measures taken in relation to electricity include:

- **Saudi Arabia:** The government approved a %30 discount on utility bills for two months for the commercial, industrial, and agricultural sectors. It also gave subscribers in the industrial and commercial sectors the option to pay 50% of the value of the monthly electricity bill for the months of April, May, and June, with the balance to be paid as installments spread over six months starting from January 2021, with the possibility of postponing the payment period if needed.

- **UAE:** The Dubai government approved a 10% reduction in water and electricity bills, as well as in deposits paid for water and electricity connections.

- **Bahrain:** The government approved the automatic payment of individuals' and businesses' Electricity and Water Authority utility bills for three months starting from April, up to the bill amounts during the same period in 2019.

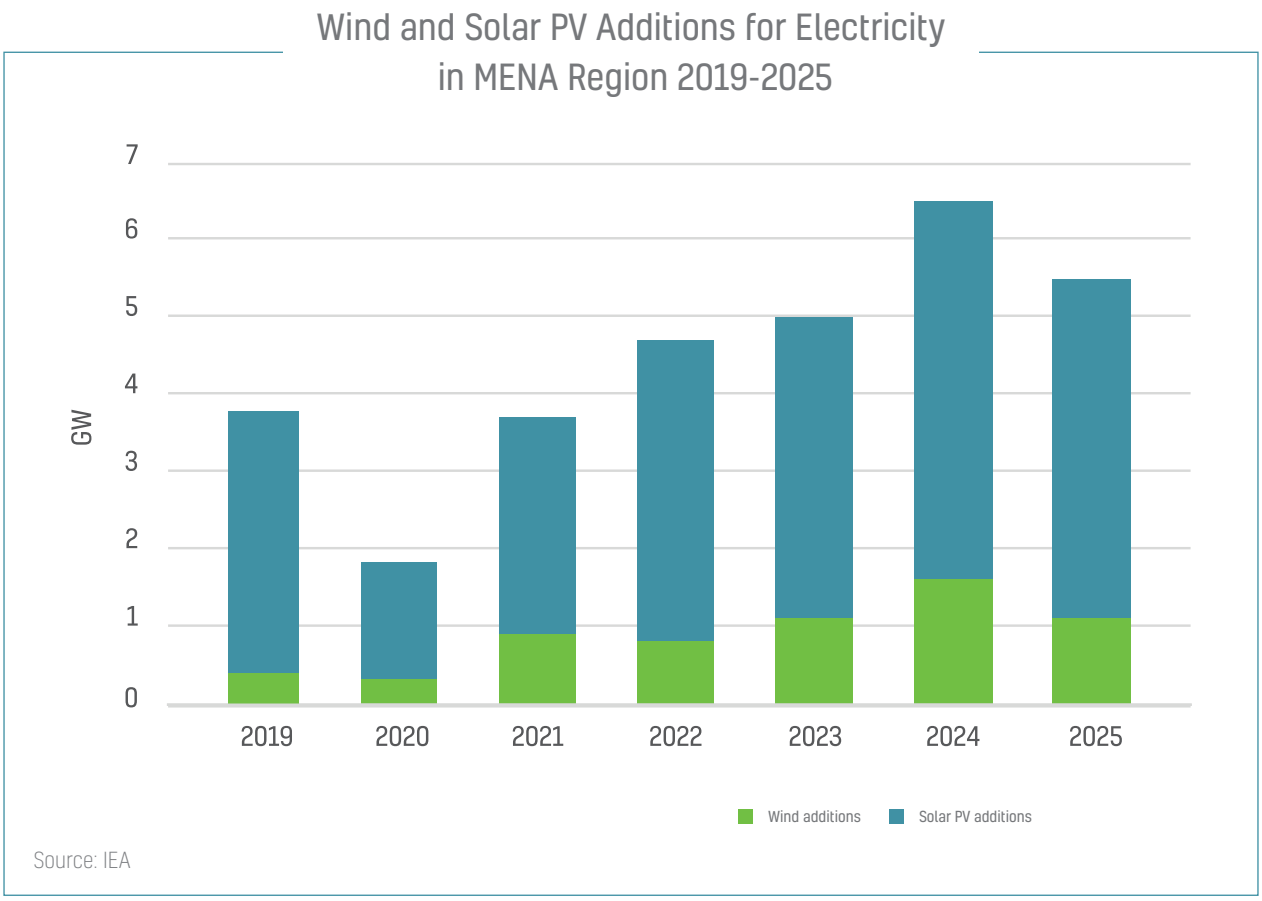
- **Egypt:** The government postponed the lifting of electricity subsidies to 2025, effectively freezing electricity prices for the next five years for extra-high, high, and medium-voltage activities, and protecting the industrial sector from subsidy cuts.

[4] Arab Union of Electricity, Statistical Bulletin, 2018.

Shift in the power supply mix

In centralized systems, power dispatching is prioritized as a function of several factors, including power plants' cost curves and power availability. As the pandemic's impact reverberated throughout the world, the level of contribution of must-run technologies such as renewables and nuclear power started to claim a higher share in the power supply mix.

According to the IEA, worldwide renewables-based generation currently comprises nearly 30% of the global generation, up 3% from 2019. The increase was driven mainly by wind power, solar PV and other sources such as hydropower. At the same time, the MENA region will add an estimated 1.5 GW of solar power in 2020 and double that figure (3 GW) in 2021, and around 20 GW over the next five years.



Source: IEA

Due to the intermittency of the renewable power sources and the lack of grid-scale storage solutions to date, fossil fuels, coal and nuclear will remain indispensable in the power supply mix in the foreseeable future. As such, the penetration of renewable power in many parts of the world will still depend on policies, subsidies and regulations, such as the EU's and US's green deals. In the MENA region, the unprecedented cost declines and government renewable energy targets – which range from 13% to 52% of installed capacity by 2030 – are the main accelerators for this penetration.

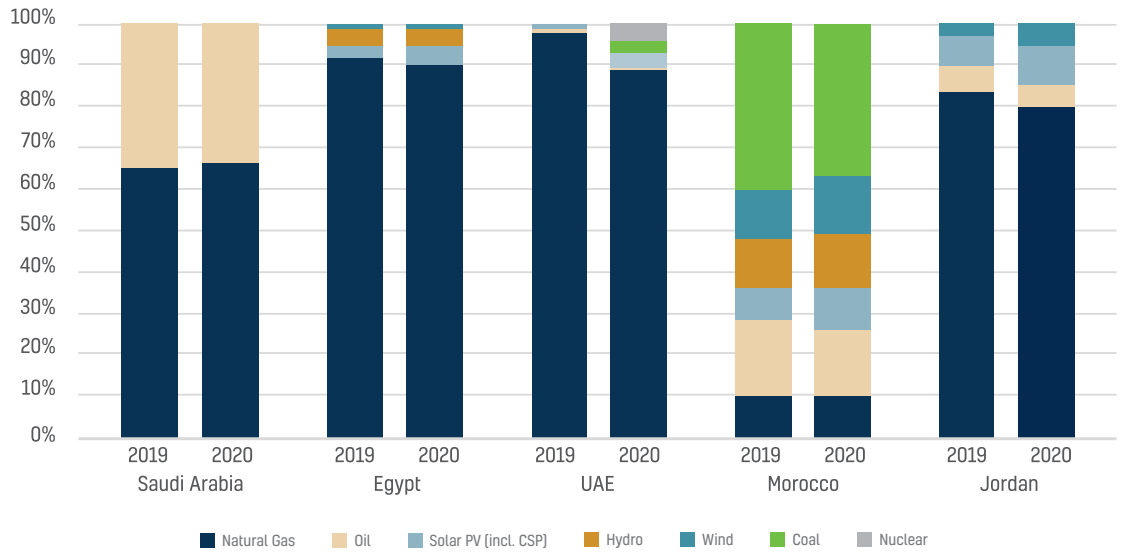
Nonetheless, natural gas continues to play a prominent role as the major energy source for power generation for many MENA countries, making up more than 90% of the power generation mix in Egypt, UAE and Algeria, and almost two-thirds of the power generation mix in Saudi Arabia.

By contrast, renewables constitute 9% of the electricity generation versus 11% of installed capacity in Egypt, and 3% of electricity generation versus 6% of installed capacity in the UAE. The share is much higher in Morocco, where renewables constitute around 37% the total generation mix versus 40% of installed capacity, driven mainly by wind, solar and hydropower.

In most MENA countries, the share of natural gas in the power generation mix fell as renewables continued to rise, falling by 2% in favor of solar PV in Egypt, and by 9% in favor of solar PV, and the partially operational coal and nuclear powerplants in the UAE.

Similarly, Morocco saw the share of oil and coal in the power generation mix fall by 2% and 3%, respectively, in favor of solar PV, wind, and hydropower. In Jordan, natural gas saw a 5% drop in favor of solar PV and wind power. Saudi Arabia's bucked this regional trend. While its power capacity mix in 2020 remained almost the same – notwithstanding the 2.3% drop in total electricity demand – yet it burned an estimated 25% more crude oil at the expense of natural gas for direct use in power generation.

The Power Generation Mix in Selected MENA Countries in 2020 vs. 2019



Source: APICORP

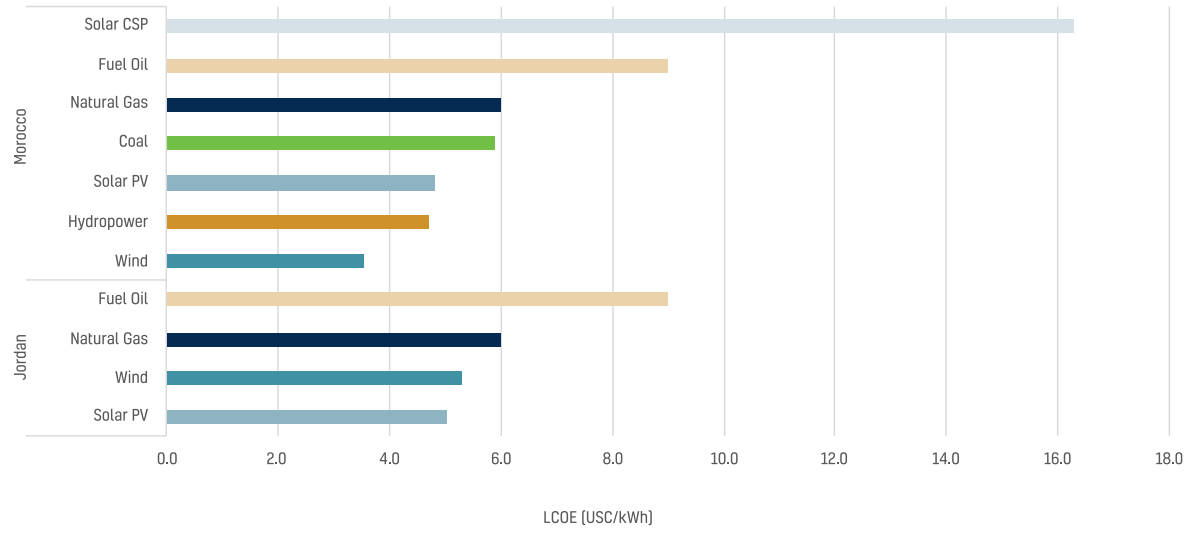
Dispatching of Renewables: Experiences in Morocco and Jordan

Morocco and Jordan are net importers of fossil fuels for power generation and regional forerunners in developing renewable sources. Jordan set its renewable electricity to total national power production target at 20% by 2020, whereas Morocco's target is 42% by 2030.

The impact of COVID-19 on the electricity sectors in the two countries is distinctive, partly due to each country's current fuel mix. When comparing their current cost profiles of the different power sources, wind, solar PV and hydropower could be considered among the cheapest sources of power supply on a levelized cost (LCOE) basis – notwithstanding legacy contracts.

It should be noted that a comparison based on LCOE has its own limitations since not all costs are accounted for, such as intermittency and energy storage costs for renewables, external factors such as risk, environmental benefits, regulatory changes, permit costs, as well as costs related to transmission and distribution networks.

Levelized Costs of Electricity by Source in Jordan and Morocco



Source: APICORP

The aforementioned 5% increase in the share of renewables in the power generation mix in Morocco was driven by wind, hydropower and solar PV. The levelized cost of electricity from renewables in the country is less than USC 5.0/kWh, which is below the cost of generation from fossil fuels and coal[5].

As for Jordan, the 5% increase in the share of renewables in the power generation mix kept up its steady pace of growth to meet the 20% by 2020 renewable target. While the levelized cost of electricity of renewables in the country is relatively higher than other MENA countries, it is still lower than the cost of supply from natural gas and oil products.

UAE: Nuclear and coal compete with natural gas

The UAE's strategy of diversifying its energy mix for power generation accelerated in 2020. The UAE Energy Strategy 2050 aims to ensure a secure power supply by diversifying the country's fuel mix and reducing its dependence on natural gas, targeting a power generation mix comprised of 44% from renewables, 38% from natural gas, 12% from coal and 6% from nuclear energy.

Clean coal and nuclear continued to steadily gain ground in the UAE's fuel mix in 2020, increasing their share in the total power generation mix at the expense of natural gas by 3% and 4%, respectively. This increase was driven by the commencement of partial operations at the Hassyan ultra-supercritical clean coal power plant (2.67 GW) and the Barakah nuclear power plant (5.6 GW) this year, with the reactors in the latter reaching 80% capacity in November. Coal and nuclear are reliable baseload providers as the UAE increase generation from solar PV and concentrated solar power (CSPs), but they both obviously have longer lead times.

The Hassyan clean coal power plant is operational under a 25-year PPA[6] with a price of USC 4.2/kWh, while gas-fired CCGTs[7] have an estimated levelized cost of energy (LCOE) range of USC 4.8-6.8/kWh at low gas prices (USD 3-4/MMBTU). Construction of the USD 3.4 billion project started in November 2016, with the three remaining units planned to start operations in 2021-2023. As for the Barakah nuclear power plant, the LCOE is estimated to be in the range of USC 8-10/kWh[8]. Although nuclear is more expensive than other conventional fuels in the UAE, it still holds a strategic importance in terms of diversifying the energy mix with a zero-carbon option, bringing more research and development and regulatory capacity building to the country and ensuring security of baseload supply.

According to Emirates Nuclear Energy Corporation, Barakah nuclear plant will provide up to 25% of the UAE's electricity needs once operating at full capacity, and it will help prevent the release of 21 million tons of carbon emissions offsetting 1 bcfpd[9] of gas annually, equivalent to taking 3.2 million cars off the road.

[5] LCOEs are calculated at: USD 3.45/MMBTU for natural gas, USD 81.7/ton for coal, and USD 325/ton for fuel oil.
[6] Power purchase agreement
[7] Combined cycle gas turbines
[8] Renewable Energy Institute, February 2019.
[9] Billion cubic feet per day

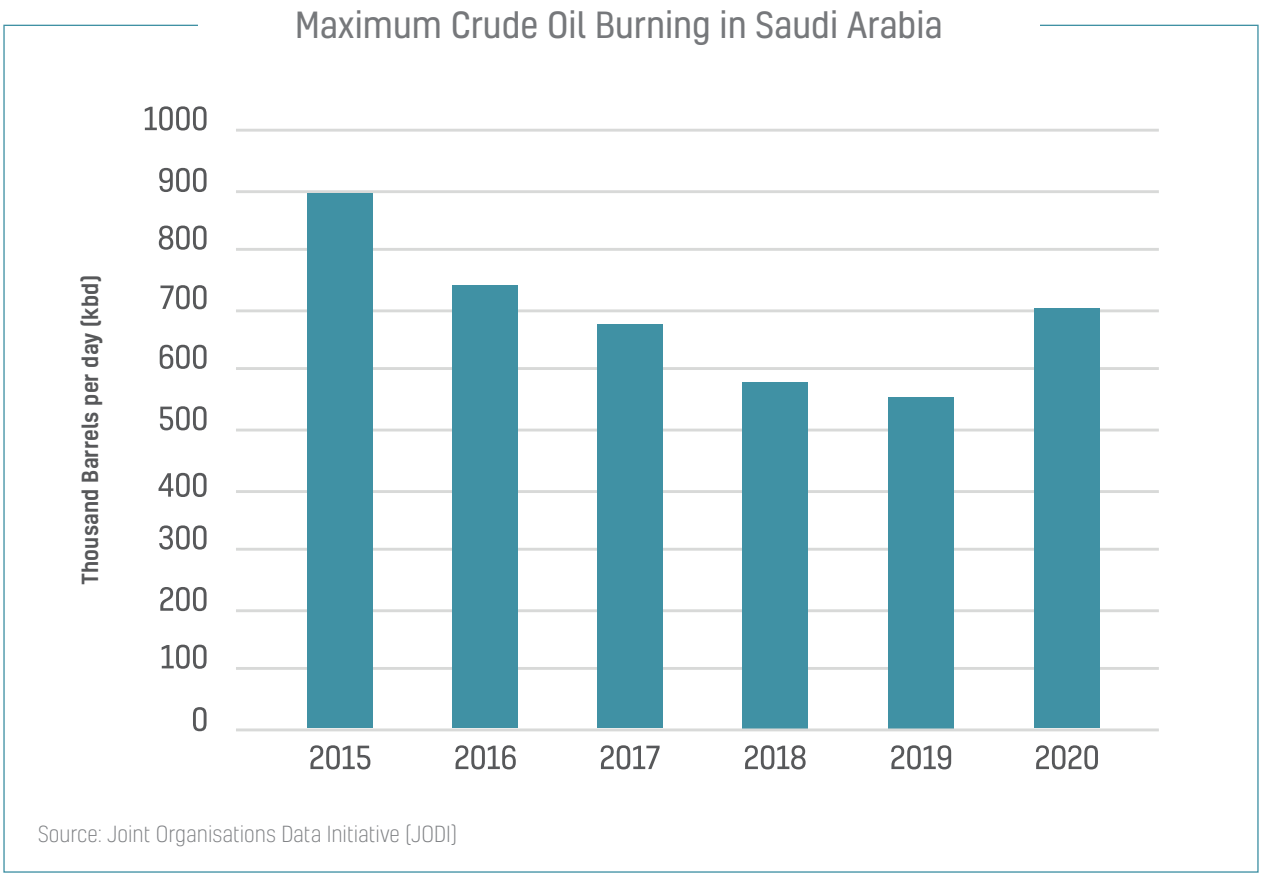
In the short to medium term, as the government continues to direct investments to domestic natural gas extraction and infrastructure, more gas could be diverted to exports and industries.

Saudi Arabia: 2020 lockdowns momentarily derailed crude burning minimization progress

Electricity load demand in Saudi Arabia typically peaks in August, and with it so does crude oil burning to use in power generation, something that the Saudi Electricity Company (SEC) and Saudi Aramco have been working in recent years to reduce. These efforts resulted in maximum crude oil burning in 2018-2019 falling to 500,000-600,000 barrels/day, a 37% drop compared to 2015.

The same downward curve was expected to continue in 2020 until the outbreak of the COVID-19 pandemic. With more people staying at home due to the widescale lockdowns triggered by the pandemic, the peak load increased during the summer months and residential electricity consumption surged, resulting in a 25% spike in crude oil burning relative to 2019.

Also, as a result of OPEC+'s oil production cuts in April, it is estimated that associated gas production has fallen by 11% relative to 2019. This happened in tandem with SEC's switching some of its diesel-fired fleet to run on crude oil.



Source: Joint Organisations Data Initiative (JODI)

Electricity demand recovery outlook

The COVID-19 pandemic may cause underlying changes to the power load profiles, a shift that may reverberate for years to come depending on the market dynamics and consuming behaviors, particularly in the residential and commercial sectors. The energy-intensive industrial sectors in MENA will take more time to evolve depending on their energy efficiency levels, use of captive generation and fuel switching possibilities.

One of these changes is the peak load profile in the residential sector, which shifted from evening to noon as people started spending more time at home due to the lockdowns and work-from-home guidelines. With around 41% of the total power demand in MENA concentrated in the residential sector, a cumulative growth in power demand is expected. This could be managed by more time-of use tariffs and increase of energy efficiency policies for power demand management.

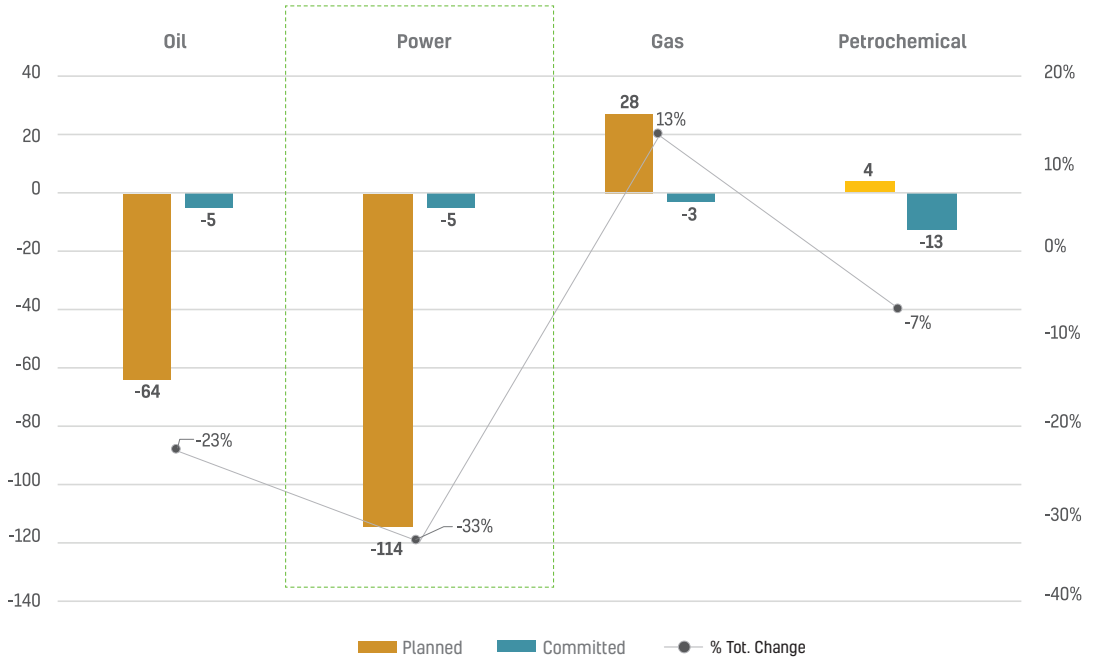
As for the commercial sector, the load profile is highly impacted by possible destruction of demand due to business closures. With the economy contracting and continued social distancing and lockdown measures, an increasing number of brick-and-mortar shops are shuttering and e-commerce is filling the gap, thus boosting the power demand for warehouses and associated supply chains. However, because the power load density in retail stores is much higher than in warehouses, the overall power demand is dropping. Electricity demand in office spaces, hotels, educational institutions, and restaurants might also fall in cases of changes in business operations.
The rebound in power demand for the commercial sector will be highly dependent on when a vaccine becomes widely available and the efficacy of the fiscal stimulus packages provided by the governments to these sectors to help them weather the crisis.

Impact on power projects

As shown in APICORP's *MENA Energy Investment Outlook 2020-2024* published in April*, committed power sector investments almost held steady in comparison with the 2019-2023 outlook, while planned investments decreased by USD 114 billion, a 33% drop. However, this considerable decrease is partly attributed to many planned projects moving to committed status in 2020 – such as Saudi Arabia's Renewable Energy Project Development Office's projects, worth around USD 6 billion. The USD 25 billion assumed for Egypt's El Dabaa nuclear plant -- a portion of the total capex -- bears a high level of uncertainty. Other factors that contributed to the decrease in planned investments were the increased surplus capacities in Egypt and Saudi Arabia, as well as stalled projects in Iran, Iraq, Tunisia and Lebanon as a direct impact of the pandemic.

* Although APICORP MENA Energy Investment Outlook 2020-2024 published in April 2020 shows a USD 1 Bn Y-o-Y reduction in committed Power investments, this has now increased to a reduction of USD 4.7 billion due to the cancelling of Hamrawein coal-fired power plant in Egypt for USD 3.7 Bn. in Q3 2020.

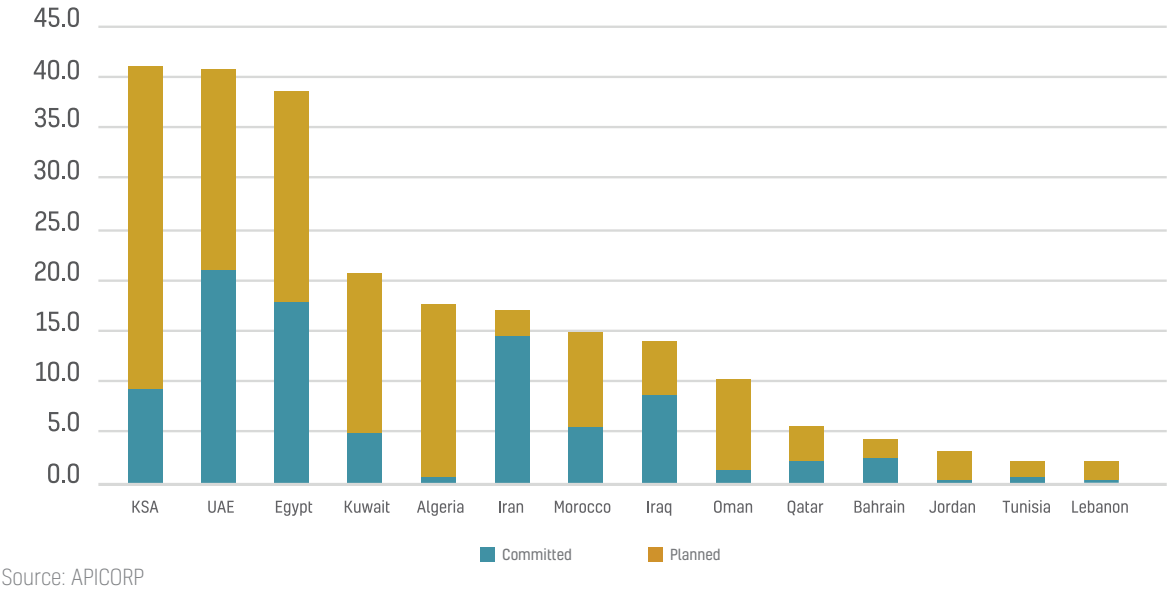
Outlook Y-O-Y Change in Investments by Sector



Source: APICORP

Planned projects represent almost two-thirds of the total value of the 2020-2024 MENA project pipeline. Despite Iraq and Iran having the most committed power projects in terms of total value, delays are expected and completion is doubtful. In Kuwait, Oman and Algeria, few projects might be postponed or cancelled altogether due to fiscal tightness.

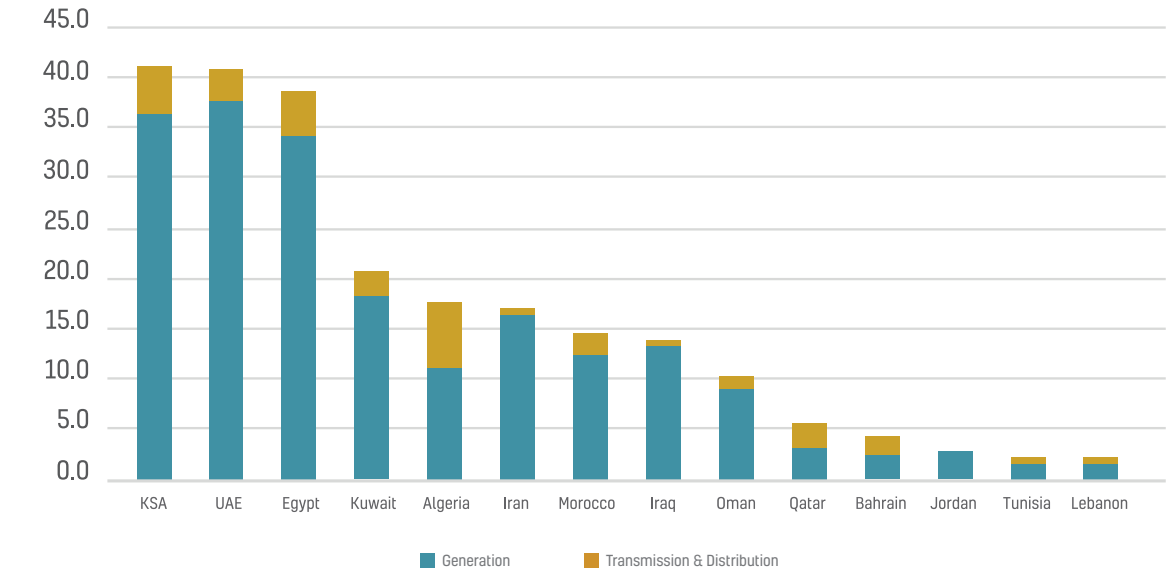
MENA 2020-24 Power investments by status (USD bn)



Source: APICORP

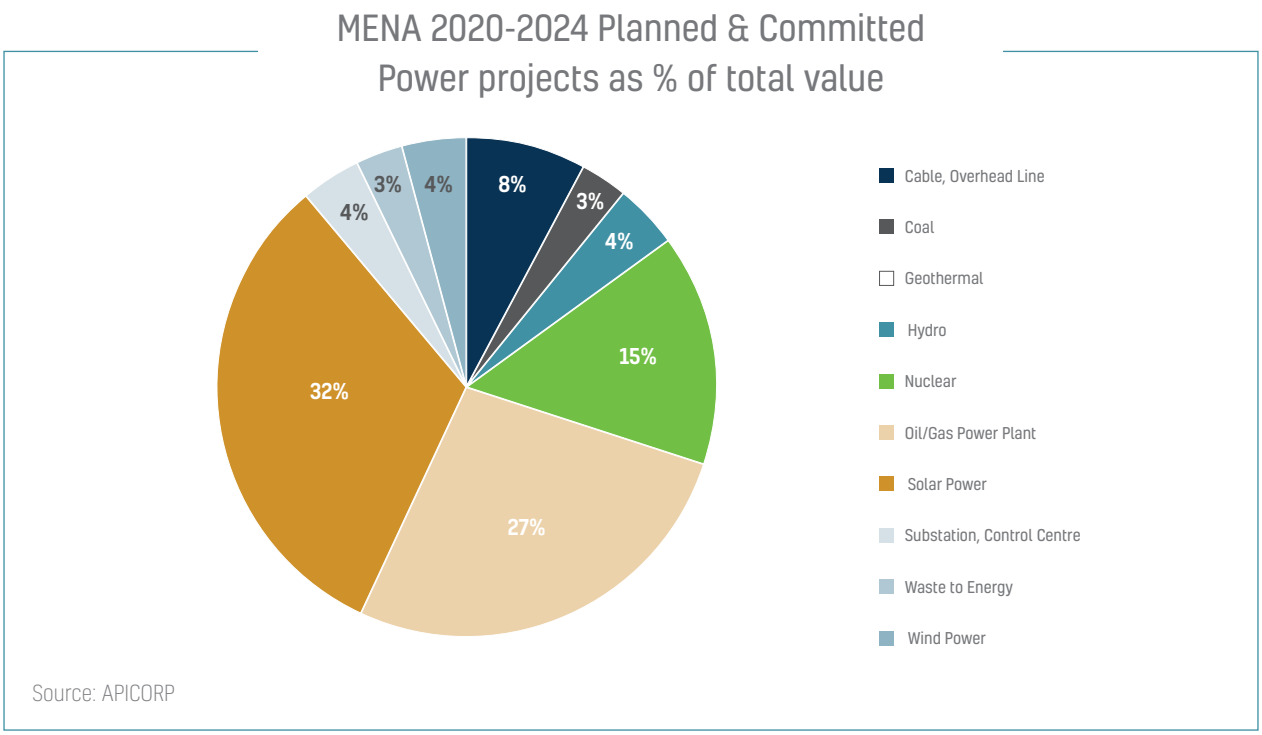
Planned investments in power transmission and distribution to strengthen the grid is expected to increase in several countries. This increase is mainly due to two factors, namely the increased penetration of renewables, and the recent push to increase regional interconnection – e.g. the 3GW interconnection between Saudi Arabia and Egypt, the 2GW Euro-Africa interconnector officially launched in October 2020 between Egypt and Europe via Cyprus , and a 164-kilometre electricity link between Jordan and Saudi Arabia.

MENA 2020-24 Power Investments by type (USD bn)



Source: APICORP

Mirroring global trends, renewables currently own the largest share of planned and committed power projects in MENA for 2020-2024 in terms of value at around one-third (32%) of total investments, followed by oil- and gas-fired power plants at more than one-quarter (27%) of total investments, nuclear power (15%) and coal (3%).



The notable solar project developments in MENA during 2020 include:

- The Ministry of Energy in Saudi Arabia extended the RFP timeframe for Round 3 of the National Renewable Energy Program (NREP) from November 19, 2020 to February 25, 2021, in light of business and travel restrictions. Round 3 is comprised of four solar PV projects with a combined generation capacity of 1,200 MW.
- Shortlisted bidders for Round 2 Category A and Category B of the National Renewable Energy Program (NREP) in Saudi Arabia were announced in April 2020 and are awaiting award of the 25-year power purchase agreements (PPAs):

    - Category A is comprised of two solar PV projects with a combined generation capacity of 70 MW. The lowest bid submitted was USC1.94/kWh for Madinah PV IPP (50 MW).
    - Category B is comprised of four solar PV projects with a combined generation capacity of 1,400 MW. The lowest bid submitted was USC1.62/kWh for Jeddah PV IPP (300 MW). The bids received for Al-Faisaliah PV IPP (600MW) from the two lowest bidders were extremely close, prompting the Ministry of Energy to shortlist the two consortia to proceed with a Best and Final Offer (BAFO). The project is expected to set a world-record low tariff.

- Egypt cancelled the 6 GW coal-fired Hamrawein power plant (budget: USD 3.71 bn) due to an increasing electricity surplus and a push for a greener power generation mix in light of future export ambitions to Europe.

- Kuwait cancelled the 1.5GW Al-Dabdaba tender as the pandemic induced a priority shift in investments.

- Qatar's 800 MW Al-Kharsaah and Oman's 500 MW Ibri-2 projects reached financial close during the crisis.

The notable developments in oil- and gas-fired power plant projects in MENA for 2020-2024 include:

- **Iraq:** A total of USD 8.3 billion of power projects have been earmarked: Maysan new gas-fired plant (USD 2.12 billion), rehabilitation of Baiji 1 & 2 gas-fired power plants (USD 1.3 billion), Rumaila combined cycle gas turbine (CCGT) plant (USD 1.26 billion), a new oil-fired power plant in West Qurna and Garraf fields (USD 300 million), phase I of the 11 GW new gas-fired power program (USD 1 billion), in addition to the renovation of smaller legacy oil-fired plants such as Al-Doura and Dibis.

- **Egypt:** USD 3 billion in committed investments have been allocated to conventional power projects, mostly modernizing legacy conventional power plants and additions of steam power generators.

- **UAE:** Committed oil- and gas-fired power generation are mostly comprised of Sharjah Electricity and Water Authority's Hamriya Independent Power Plant (USD 1.55 billion), Layyah CCGT (USD 200 million), and Dubai Aluminium's (DUBAL) captive power plant (USD 193 million) as well as various Dubai Electricity and Water Authority municipal substations.

- **Saudi Arabia:** USD 2 billion in committed oil and gas power projects, including a number of SEC CCGT power plants (USD 1.78 billion), Aramco's Jizan integrated gasification combined cycle plant (IGCC), Fadhili independent power plant (IPP), Shedgum expansion, as well as the joint Saline Water Conversion Corporation (SWCC)-Power and Water Utility Company for Jubail and Yanbu (Marafiq) Yanbu desalination power plant (USD 100 million).

- **Kuwait:** Al Zour Independent Water and Power Plant (IWPP) megaproject (USD 3.72 billion).

- **Bahrain**: Al Dur IWPP (USD 1.39 billion).

- **Oman:** Duqm power plant (USD 425.5 million).

- **Algeria:** Mostaghanem CCGT (USD 213.7 million).

- **Tunisia:** Mornaguia gas-fired plant (USD 55.5 million).

- **Iran:** Committed conventional power projects for the period are estimated at USD 6.63 billion.

- **Lebanon**: The country's sole committed oil and gas power project, the Deir Al-Ammar expansion (USD 265.3 million), is awaiting contract signature and project bankability.

Coal-fired power generation comprises 3%, or USD 6.97 billion, of total committed and planned projects in the MENA region between 2020 and 2024, driven mostly by the objective of bolstering energy security perspective -- most planned projects -- and rehabilitation of legacy power plants, as is the case in Iraq and Iran.

Country	Project	Status[10]	Total in USD Bn
UAE	FWA - Coal Fired IPP 1800 MW in Ras Al-Khaimah	P	2.18
	Hassyan Energy Company - Hassyan Coal Fired IPP (Phase 1 & 2)	C	1.25
	DEWA - Hassyan Coal Fired IPP (Phase 3)	P	1.17
Oman	OPWP - 1200MW Duqm Coal Fired IPP	P	0.99
	Hebei / Ningxia Electric JV - SEZAD - 300MW Coal Power Plant	P	0.41
	OCC - 30MW Coal/Petcoke Based Power Plant in Duqm	P	0.03
KSA	Saudi Aramco - Jubail Petcoke Cogeneration Power Plant	P	0.69
Iraq	MoOE - Rehabilitation of Hartha Power Station: Unit 1	C	0.11
Iran	Thermal Power Plants Holding Co. - Ramin Plant Upgrade	P	0.15
	Grand total		**6.97**

Source: APICORP, MEED Projects

[10] P: Planned/C: Committed

II. MENA Power Market Highlights: Regulatory reforms impacted differently by COVID-19

Power market highlights

The role of the private sector and financing is still largely dependent on sector reforms and government guarantees. Most countries in the MENA region followed the Single Buyer Model anchoring long-term PPAs. Typically, highly-leveraged power projects in the region continue to be largely financed based on non-recourse or limited recourse structure, with typical debt-equity (D/E) ratios in the 60:40 to 80:20 range, or even a 85:15 D/E ratio for lower risk projects backed by strong government payment guarantees. However, regulatory reforms to support renewables and the impact of the 2020 crisis at times questioned this pre-established balance.

In Egypt, for example, the Ministry of Electricity amended its plans for electricity subsidies with a three-pronged plan:

- Pushing the deadline to lift electricity subsidies by three years to mid-2025.
- Freezing electricity prices for the next five years for extra-high, high, and medium voltage activities.
- Subsidizing electricity for the industrial sector by 10 piasters per kilowatt/hour for the next five years.

While this plan effectively guarantees investors that electricity costs will remain as they are for five years, the delay in electricity market liberalization is partly denting the wheeling scheme (refer to the appendix for more information).

Egypt took advantage of the opportunity presented by the 2020 crisis to accelerate progress on its most capital-intensive projects, namely government funded projects. The most notable project is the USD 29.5 billion El Dabaa Nuclear Power Plant for which groundworks and site preparation commenced in October 2020. This includes qualifying bids for construction contractors after the joint approval from Rosatom, the Russian state nuclear company, which will build the plant. Russian banks are financing USD 24.5 billion of the project through a long-term loan to the Egyptian government which will in turn finance the remaining USD 5 billion.

By contrast, Saudi Arabia prioritized the restructuring of its electricity sector in 2020, in particular the financial situation of SEC, its national utility company. The Kingdom targets a staggering 27.3GW of renewable energy capacity by 2024, 30% of which will come from REPDO projects and the remaining 70% from Public Investment Fund (PIF) projects. The PIF projects are awarded on a direct basis to fast-track localization, foster technology transfer to the Kingdom and hasten project delivery.

Sudair, a 2GW CSP project, has been delayed and subsequently downsized to 1.05 GW due to price renegotiations following record-low bids – around USC 1.62/kWh – for REPDO projects and the ongoing slump in oil and gas prices. These two factors have strained the attractiveness of utility-scale renewable energy projects versus gas-fired CCGTs. In Q3 2020, Ras Al Khair 2.65 GW power and desal plant majority share privatization was announced under the standard Saudi IWPP/IPP framework.

Interestingly, two Category A REPDO projects, Madina and Rafha PV IPPs, are being financed through a 66:33 D/E ratio, while conventional power Jazan IGCC is being financed with 60:40 D/E ratio. For brownfield refinancing, Qurayyah 3.9 GW IPP (CCGT) in KSA has been refinanced on an 85:15 D/E ratio.

Saudi Electricity Company's Debt Restructuring

In an effort to improve its business model and ensure financial sustainability, the Saudi government approved to reclassify SAR 167.92 billion (USD 44.77 billion) worth of SEC's government liabilities, including all past fuel payables, into a subordinated perpetual non-dilutive equity like financial instrument with a profit rate of 4.5% per annum. This financial instrument represents about 33.4% of SEC's total assets by the end of 2020. This instrument is unsecured and deeply subordinated (junior to all senior payments and obligations).

The Saudi government also cancelled government fees amounting to around SAR 14 to 15 billion (USD 3.7 to 4 billion) per annum, opting for an operating revenue cap model for the fiscal year 2020 and ensuring payment of dividends to all of SEC's shareholders, including the PIF.

A Regulatory Asset Base (RAB) model as a mechanism to regulate SEC's revenue will also go into effect as of January 1, 2021. The RAB model's required rate of return is set at 6% by the regulator, reflecting a fair cost of capital for a 3-year term ending on December 31, 2023. At the time of writing, the RAB structure is still under discussion, but preliminary insights suggest that assets will be valued based on historical costs. In addition to return on RAB, the required revenue will also include a depreciation allowance and allowed operating expenditure.

This framework is expected to allow SEC to meet its operational expenses, including fuel expenses to Saudi Aramco, its financial obligations and equity returns to all shareholders. Tariff setting and balancing account – i.e. required revenues minus actual revenues – will be subject to the regulator's review and the stakeholders' consultation.

Country focus: Lebanon's Power Market

Sector Overview

Lebanon is undergoing a full economic meltdown accelerated by civil unrest, political instability, the Beirut port's explosion on August 4, 2020, and a worldwide pandemic. These calamities caused inflation rates to skyrocket and the value of the Lebanese pound to tumble by approximately 80% over a course of one year.

At the heart of it all lies the ongoing crisis in the power sector, which has accelerated the country's economic collapse due to the sector's network inefficiencies, high operational costs, unbearable subsidies and political hegemony.

The annual budgetary transfers from the Lebanese State to Electricité du Liban (EDL) amounted to 2% to 4% of GDP. It was estimated that the electricity sector's fiscal deficit reached USD 36 billion, around 40% of the country's overall fiscal deficit in 2019.

The average electricity tariff is set at 9.87 USC/kWh, unchanged since 1994, while the cost of power supply ranges between 13 - 20 USC/kWh at an oil price of 65 USD/bbl. At lower oil prices of 45- 50 USD/bbl, the average cost of supply ranges between 10 - 17 USC/kWh.

There are two CCGTs in Beddawi and Zahrani sites with a maximum capacity of 465 MW each, currently running on imported diesel oil. The reciprocating engines in Zouk and Jieh sites run on imported heavy fuel oil with maximum capacities of 194 MW and 78 MW, respectively. Two floating power ships have been contracted by the Lebanese state on an energy-conversion agreement (ECA) basis currently running on imported heavy fuel oil with a capacity of 190 MW each. Although thermal power plants represent most of the power generation, Lebanon also depends on electricity imports from Syria and Egypt as well as on hydroelectric power.

All this amounts to around 1,600 MW in generated power, which is just half the estimated 3,200 MW the country needs. This power deficit results in daily power load shedding all over the country, forcing consumers to depend on decentralized semi-regulated privately-owned diesel generators. For the average consumer, this is an expensive source of power supply with a tariff ranging between 17 - 27 USC/kWh. To secure a steady supply of power, Lebanese consumers are essentially paying two electricity bills.

Grid Losses

Around 40% of the energy produced in Lebanon is lost in the network due to operational inefficiencies, grid bottlenecks and wide-scale evasion of bill payment. Losses in the low-voltage (LV) network are the largest, followed by the high-voltage (HV) and medium-voltage (MV) networks. Together with unbilled energy, this amounts to around USD 500 million per year in lost revenue for EDL.

Governance Structure

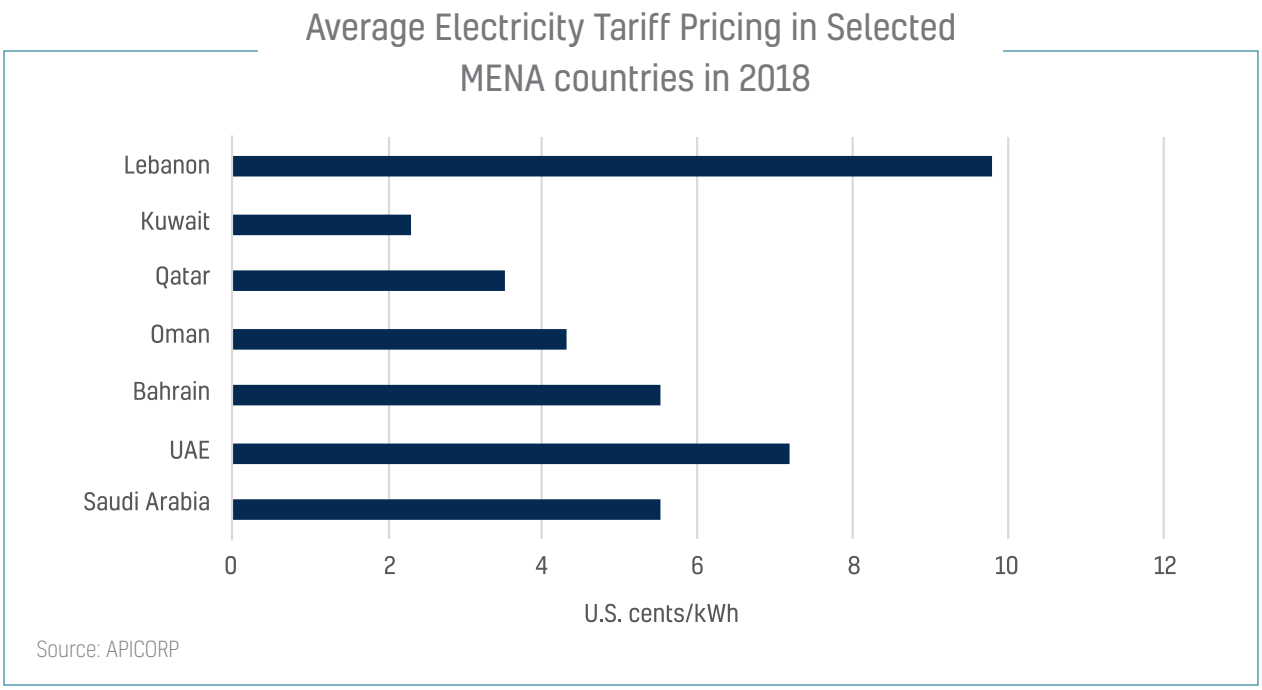
The Lebanese state has been trying over the past 10 years to address the issues in the electricity sector by maintaining a crisis management policy while at the same time unsuccessfully attempting to implement its electricity policy plans due to the political impasse. With the core governance issues not properly addressed, the sector's situation is fastly becoming a bigger national catastrophe.

By securing only temporary sources of power generation, the sector is fiscally inefficient. EDL has no financial autonomy and is subject to the dual control of the Ministry of Energy and Water (MoEW) and the Ministry of Finance (MoF). While increasing generation capacities and enhancing the transmission and distribution networks is indeed important, corporatization of EDL and transforming it into a commercial entity that generates profit and is financially viable should be the first priority. This involves modernizing the operational performance, business functions and the administrative aspects while dividing responsibilities between all stakeholders.

"Law 462/2002" was drafted for this very purpose, setting the "rules, principles and framework governing the electricity sector, including the Government's role in this sector, the principles and bases regulating it, as well as the rules governing the total or partial transfer of this sector or of its management to the private sector." The law envisioned the establishment of the Electricity Regulatory Authority (ERA), but none of the amendments made to the law since that time were implemented.

Tariff Structure

The tariff structure is based on an incremental block structure which provides heavily subsidized rates for all consumers in the initial consumption blocks. This means that households as well as commercial entities receive highly subsidized power for energy use up to 500 kWh. It is estimated that around 40% to 45% of EDL's revenue comes from the last consumption block (>500 kWh per month) of residential and commercial customers.



Recommendations

Since nearly 70% of EDL's expenses are related to fuel costs, switching from liquid fuels to natural gas would significantly change the Lebanese power market landscape and save the country up to USD 1 billion per year. However, the only existing gas infrastructure in place currently is a piped connection from the Arab Gas Pipeline which passes through Syria to the Deir Amar power plant (Beddawi site) in the north.

To bolster its natural gas capabilities and infrastructure, the Lebanese state's current plan is to import LNG, build three FSRUs (floating, storage and regasification units) and a coastal pipeline that would form the backbone of the natural gas grid that connects to the country's coastal power plants. The project however has not materialized since it was first proposed in 2013.

Another key action required in the short-medium term is to reduce the network losses in the transmission and distribution networks. Technical losses in the MV/LV networks should be mitigated by addressing congestions and bottlenecks and upgrading the network. Losses from non-technical issues, such as fraud and bill evasion, can be addressed by rolling out smart meters on a national scale.

EDL's structure requires immediate modernization. The legal, financial, technical and operational performance should be enhanced for the sector's long-term sustainability and financial viability. This should be done in tandem with implementing Law 462/2002.

Generation capacity needs to be increased in the short-term by at least 1.5 GW and 3.2 GW in the long term. As per the updated sector policy published by the MoEW in March 2019, new gas fired CCGTs are envisioned in several coastal areas while securing temporary generation to meet the deficit in power supply. Developing the country's renewable power sources, mainly solar and wind, is a strategic initiative.

Regarding the tariff, the most important objective is to ensure cost recovery and price the commodity in a manner to cover its cost of supply. This can be done by indexing the tariff to fluctuating market variables, such as the fuel price and foreign currency exchange. More urgently, a more efficient tariff structure should be established.

[11] Liquified natural gas

III. Hydrogen ambitions accelerating the penetration of low-cost renewable energy sources

With an increased focus on electrification of the economies through low- or zero-carbon sources, hydrogen is emerging as a promising energy carrier. Whether used as a feedstock for industrial and chemical purposes, blended with natural gas for power generation, used in fuel cells as transportation fuel or used to store excess renewable energy, hydrogen's spectrum of utilization is extensive. The cost elements and the export potential will determine if it emerges as a strong export proposition from the MENA region, whether it be green hydrogen produced from renewable energy sources and/or blue hydrogen produced from hydrocarbons with carbon capture utilization and storage (CCUS) technology.

As the cost profiles of renewable energy sources decline due to advancements in technologies mainly solar, wind and electrolyzers, green hydrogen is expected to become more cost-competitive over time. However, due to low natural gas prices in the MENA region, blue hydrogen will play a key role in the short to medium term.

At gas prices of USD 3-4/MMBTU[12], the levelized cost of blue hydrogen (LCOH) is estimated to be around USD 1.5/kgH in the MENA region based on SMR (Steam Methane Reformer) and CCUS technologies. The LCOH for green hydrogen is estimated to be between USD 2.1/kgH to USD 3.6/kgH for Alkaline electrolyzers and USD 2.3/kgH to USD 3.8/kgH for Polymer electrolyte membrane electrolyzers. As costs of renewable energy sources and electrolysers decline, the competitiveness of green hydrogen is expected to improve.

The combination of low-cost gas resources and low-cost renewable energy positions the MENA region as a strong candidate for becoming a major hydrogen-exporting region, whether it be blue or green. A few countries, such as Saudi Arabia and Morocco, have actually taken measurable steps to positioning themselves as low-cost exporters of blue and green hydrogen, in addition to net-zero ammonia and other low-carbon products.

Saudi Arabia is testing different approaches. Saudi Aramco, in partnership with SABIC with the support of the Japanese Ministry of Economy, Trade and Industry, exported 40-ton demonstration shipment of blue ammonia to Japan, a country which can generate about 10% of its power from 30 million tons of this product.

To make blue ammonia, Saudi Arabia is using domestically produced natural gas to make blue hydrogen, which is then mixed with nitrogen. The associated carbon dioxide generated during natural gas processing is captured and used for enhanced oil recovery at Saudi Aramco's Uthmaniyah field and production of methanol at SABIC's Ibn Sina facility.

[12] Million British thermal units

On a larger scale, Air Products announced in July 2020, a USD 5 billion joint green hydrogen project with ACWA Power in the futuristic Saudi city of NEOM powered by 4GW of renewable energy. The plant will use solar and wind power to produce hydrogen from water then mix it with nitrogen from the air to produce 1.2 Mtpa[13] of ammonia as a carrier for green hydrogen. Air Products also plans to invest USD 2 billion in distribution infrastructure, including depots to turn the ammonia back into hydrogen for buses, trucks and cars. The project is expected to start operating by 2025.

Capitalizing on Europe's hydrogen strategy, Morocco is pursuing a more aggressive route that aims to build a 'power-to-X' industry using renewable electricity to create green hydrogen, synthetic gas, ammonia for fertilizers and industrial liquids. With 20,000 MW of potential solar PV capacity and 6,500 MW for wind versus an installed renewable capacity of 3,685 MW -- including 1,770 MW hydro, 1,215 MW solar and 700 MW wind -- the country is essentially communicating on its green hydrogen potential, as demonstrated by the MoU signed in July 2020 with Germany to build Africa's first industrial green hydrogen plant. However, it is still uncertain whether the country will opt to become fully dependent on renewables, or if it will be open to a more flexible strategy to produce blue hydrogen and ammonia using natural gas, especially given the massive investment needs in solar and wind to produce enough hydrogen and ammonia for local consumption and exports.

Other MENA countries are at various stages of progress. For example, Abu Dhabi Department of Energy signed an MoU in January 2020 with Japan's Marubeni to study the feasibility of hydrogen production using renewable energy, while DEWA and Siemens signed an MoU in February to build a pilot project for the region's first solar-powered hydrogen facility in Dubai's MBR Solar Park.

[13] Million tons per annum

IV. Cross-border electricity interconnections and regional integration

Another major trend which could have been accelerated in 2020 is that of regional electricity integration, but it was hindered by the COVID-19 crisis. Currently, the MENA region consists of three cross country-grids:

- North African countries are connected with lines linking Algeria, Morocco, and Tunisia.
- Egypt is connected to the Levant through the Mediterranean grid, albeit through small transmission lines.
- GCC countries are connected via the Gulf Cooperation Council Interconnection Authority (GCCIA)

One of the major electricity grid interconnections in the Arab world started in 1988 with the Mediterranean grid that linked Egypt, Iraq, Jordan, Syria and Turkey. It later expanded to include Libya, Lebanon and Palestine. The two critical countries that remain to be linked for the completion of the grid are Saudi Arabia and Egypt.

In North Africa, the Maghreb interconnection began much earlier in the 1950s and connected Algeria, Morocco and Tunisia. Morocco also imports nearly 20% of its electricity from Spain where the two countries have been connected since the late 1990s. Plans to link Algeria and Tunisia with other Mediterranean countries have also been proposed but saw little progress.

The GCCIA was established in 2001 by the six GCC Member States to foster cooperation and interconnect their respective grids. Saudi Arabia and Kuwait are linked with 1.2GW of transmission capacity, while the UAE and Qatar have 900MW and 750MW connections to the system. The remaining two countries, Bahrain and Oman, can deliver up to 600MW and 400MW, respectively.

More recently, construction of the first phase of a two-phased 300 MW interconnection project between Egypt and Sudan was completed in March 2019 and the first link (50 MW) started operating in early 2020.

Interconnection	Export (MW)	Import (MW)
Algeria-Tunisia	150	150
Morocco-Algeria	400	400
Morocco-Spain	700	700
Syria-Jordan	200	350
Syria-Lebanon	50	160
Jordan-West Bank	20	-
Egypt-Gaza	17	-
Turkey-Syria	250	-
Libya-Egypt	180	180
Jordan-Egypt	200	450
Saudi Arabia-GCCIA	1200	1200
Kuwait-GCCIA	1200	1200
Qatar-GCCIA	750	750
Bahrain-GCCIA	600	600
UAE-GCCIA	900	900
Oman-GCCIA	400	400

Source: World Bank

Regional integration in the electricity sector in the MENA region is of high strategic importance to ensure energy security. Electrical integration within the GCC countries was formalized in 2011 under power exchange and trade agreements. However, the utilization rate of this network is less than 10% since it is used mainly for emergency and reserve sharing instead of economic market viability.

Egypt currently trades electrical power with Libya and Jordan, while other planned regional interconnections are slow on progress. Egypt signed an MoU with Saudi Arabia in 2013 for a 3,000 MW HV-DC interconnection to be completed by 2021, but the project was delayed several times, including in 2020 due to the COVID-19 crisis.

The seasonal peak in Saudi Arabia typically runs from the end of August to early September, whereas Egypt's peak runs from the end of July to early August. During summertime, the daily peak load time in Saudi Arabia occurs during the weekdays at 2:00-2:30 pm, while in Egypt the peak load time usually occurs at 8:00 pm.

Saudi Arabia	Peak Load Time[14]	GW
2019	Sep. 01	62.1
2018	Sep. 02	61.7
2017	Aug. 22	62.1

Egypt	Peak Load Time[15]	GW
2019	July 31	30.8
2018	July 25	31.4
2017	Aug. 13	30.8

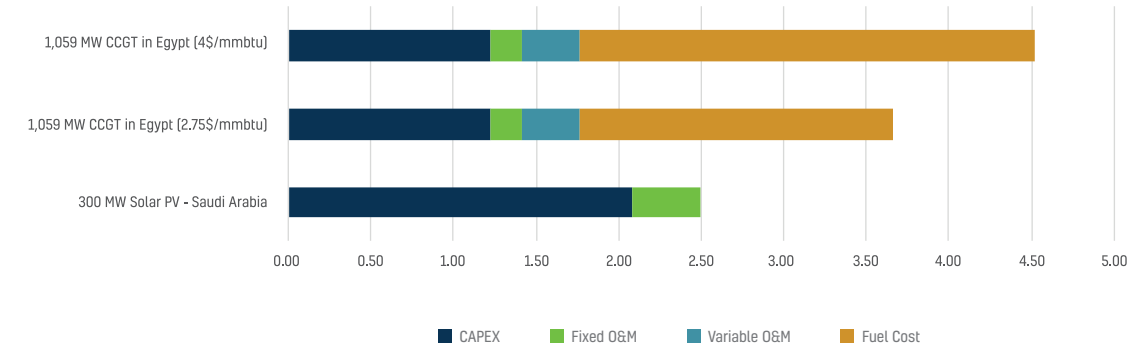
Source: ECRA, EEHC

[14] Electricity & Cogeneration Regulatory Authority, Annual Statistical Booklets for Electricity and Seawater Desalination Industries, 2017-2019
[15] Egyptian Electricity Holding Company, Ministry of Electricity and Renewable Energy, Annual Reports, 2017-2019

This difference in peak load timing makes a regional interconnection between the two countries an appealing value proposition, as excess power output could be traded.

The proposition's appeal is further enhanced by the cost discrepancy. A simple LCOE economic modeling exercise was conducted in preparing this report to compare the cost of energy between a theoretical 1,059-MW gas-fired CCGT in Egypt under two different natural gas pricing scenarios, and a 300 MW solar PV farm in the western coast of Saudi Arabia. The natural gas pricing scenarios in Egypt are considered at USD 2.75 /MMBtu and USD 4/MMBtu based on existing gas-sales agreements.

Levelized Cost of Electricity Comparison between CCGT and Solar PV for an interconnection between Egypt and Saudi Arabia



Source: APICORP

Based on the calculations, the 300-MW solar PV project in Saudi Arabia has an LCOE of USC 2.5/kWh, with 84% of the cost as capital expenditure and 16% as operation and maintenance (O&M) costs.

As for the CCGT power plant in Egypt, based on a USD 2.75/MMBtu natural gas price scenario, the resulting LCOE is USC 3.7/kWh. Based on a USD 4/MMBtu price scenario, the resulting LCOE is USC 4.5/kWh. In both cases, fuel cost represents 50% to 60% of the total cost.

In practical terms, natural gas prices in Egypt need be less than USD 2/MMBtu for the CCGT to be cost-competitive with the solar PV power plant in Saudi Arabia. More details about the Egyptian renewables sector can be found in the Appendix.

While these figures demonstrate the appeal of electricity trading between the two countries, this simple calculation will need to be fleshed out to include transmission costs, actual dispatch costs, and other additional benefits that an interconnection between Saudi Arabia and Egypt brings to the wider regional integration.

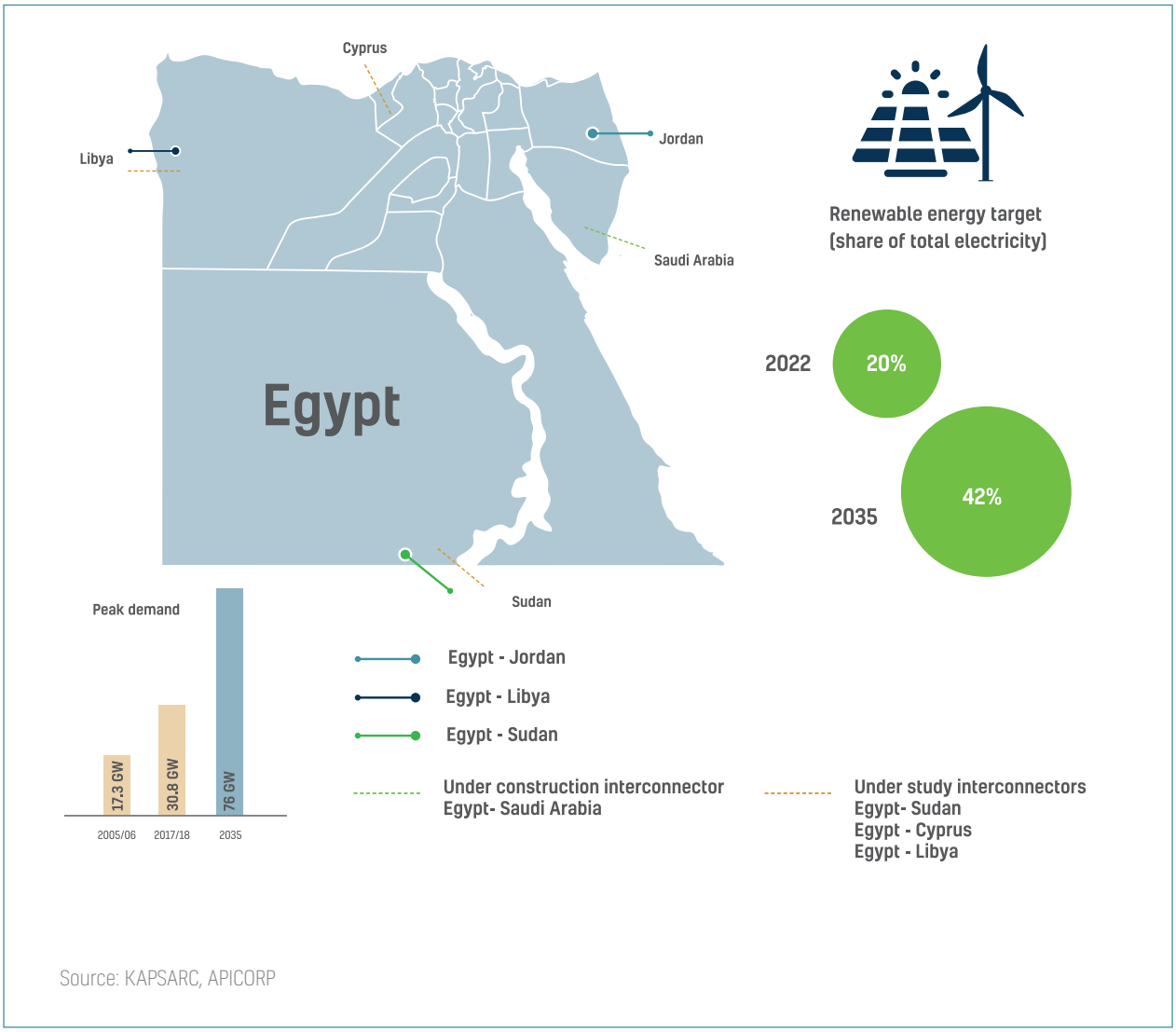
V. Conclusion

The MENA electricity sector has come out *relatively* unscathed from the 2020 COVID-19 pandemic compared to other energy sectors, and it is expected to play a vital role in driving and accelerating the recovery process. Among numerous variables, the power market structure and regulatory reforms were affected differently within countries. In all cases, policy efficiency and the digitalization of the sector weigh in as the most influential factors in the future for power demand and investments. The rise of the MENA region as a more interconnected market, and as a potential exporting region for net-zero products such as hydrogen and ammonia, should be the vision that policymakers strive to achieve.

VI. APPENDIX

Renewables Power Sector in Egypt

The Egyptian Government set its national renewable energy targets at 20% of the electricity generation mix by 2022 and 42% by 2035, compared to an installed capacity of approximately 11% in 2020. Electricity peak demand, meanwhile, is expected to reach around 70-85 GW by 2035.



Source: KAPSARC, APICORP

Provided they obtain the necessary generation licenses, independent power plant (IPP) in Egypt may sell electricity to private consumers under two different schemes: A net-metering scheme and a wheeling scheme. Both schemes are regulated by the Egyptian Electricity Utility and Consumer Protection Regulatory Agency (EgyptERA) and involve the relevant network operator, be it the relevant Distribution Company (DisCo), or the Egyptian Electricity Transmission Company (EETC).

1. Net metering scheme – Active:

The net metering scheme, regulated by EgyptERA, allows consumers who have a solar plant on their premises – whether rooftop or ground-mounted – to contract with EETC or DisCo, depending on their connection voltage, for the installation of a bi-directional meter in order to offset their electricity consumption with the excess electricity they feed back to the network. The regulations also recognize the consumer's right to enter into a Power Purchase Agreement ("PPA") with a third-party solar energy developer.

The net metering scheme - as recently amended in May 2020 - requires power plants owned by one customer to have either a cap of either 25 MW cumulative of several solar net-metering projects connected to the distribution network, or 20 MW per project. Any excess to the offtaker's electricity bill offsets is accredited to the offtaker's month-to-month balance until the end of the DisCo's/EETC's financial year, which falls on June 30.

Any outstanding credit at the end of the financial year is bought by EETC or the DisCo at a price equivalent to the average cost of electricity produced. This price, which is usually low, is determined in accordance with the latest service cost report announced annually by EgyptERA. Yet while net-metering for consumers connected to the transmission grid is theoretically possible under regulations, no template agreement with the EETC has yet been published.

Further, EgyptERA introduced a new integration fee in May 2020 to be borne by net-metering projects. This fee represents the integration charge of solar energy into the distribution network or the transmission grid, which in turns relates to the production of energy and is not considered as a wheeling fee. In the case of a MV network connection, an additional study should be conducted by DisCo or by third parties to assess the impact on the network at the customer's expense, ensuring that there is no reverse current that feeds the transport networks of the EETC or one of its customers in any event. The cost of this study will also be borne by the client, be it the offtaker or the solar developer.

Parameters of the Net-Metering Scheme

The net-metering scheme applies solely to solar energy projects and allows for excess energy generated by the power plant to be evacuated to the relevant distribution network or the transmission grid. The net-metering scheme is further subject to the following parameters:

1. The plant must be connected to a network, either the transmission grid for hyper and high voltages, or a distribution network for medium and low voltages.
2. The power plant's capacity must not exceed 25 MW cumulatively, or 20 MW per project.
3. The consumer may not hold a distribution license for the same net-metering project.
4. The total installed capacity of solar power plants projects connected to any single DisCo may not exceed 1.5% of the peak load of the DisCo registered by the meters during the financial year preceding the contract. The available capacities for each of the nine DisCos operating in the country were published by EgyptERA in August 2020.
5. The total capacity generated from solar net-metering projects, past and future, may not exceed 300 MW. It is understood that the remaining available capacity is currently set at 225 MW, which is to be split into the two following chips:
    a. 125 MW for capacities up to 500 kW.
    b. 100 MW for capacities greater than 500 kW up to 20 MW.
6. To avoid consumers backing up the extra capacity on the grid and oversizing the station, EgyptERA stipulates that the installed power of the net-metering station cannot exceed the maximum load of the consumer during the fiscal year prior to the commercial operating date of that power plant

Renewable Energy Certificates (RECs):

As per the net-metering regulations, Renewable Energy Certificates ("RECs") shall be issued by EgyptERA to the customer – i.e. the offtaker – evidencing the renewable origin of each MW/h, provided that the power generated from the solar plant is not less than 1 MW/h per month. It is worth noting that the rules with respect to the issuance, trading, and redemption of RECs have not yet been formally issued by EgyptERA. However, this indication in net-metering rules may not be in line with some expectations that the RECs will be tied to the power generation license, in that they will be issued by EgyptERA to the licensee entity, which is the solar developer and not the offtaker.

2. Wheeling scheme – Inactive:

Under the approved but still inactive wheeling scheme, an IPP can construct a plant of any capacity and energy type and utilize the transmission grid operated by EETC or a distribution network operated by a DisCo to sell electricity to offtakers connected to the same network. Access to the transmission grid or distribution network is granted in exchange for a wheeling fee.

The wheeling fee is published by EgyptERA and revised every 2 years, but it can be amended by EETC or the relevant DisCo subject to EgyptERA's approval. This means that moving the burden to the offtaker on a full carry-forward basis or other methods to shift such risk is important in order to preserve the economic balance of the PPA. In this respect, many offtakers usually push back on a complete pass-through of the wheeling fee, considering it as an unidentifiable risk. Some relief may be derived from the fact that the applicable wheeling fee is also part of the utility tariff applicable to the offtaker. Hence, an increase in the wheeling fee will automatically translate into an increase in the utility tariff applicable to the offtaker, unless the government decides to partially subsidize the tariff.

To date, only transmission grid's wheeling fee has been announced by EgyptERA, with no such announcement yet for the distribution network. From a regulatory perspective, the Electricity Law explicitly imposes an obligation upon DisCos to make their networks available for wheeling with no preferential treatment and on the same tariffs and terms for all participants. Accordingly, no regulation prevents from wheeling on the distribution networks. In practice, wheeling is still not available on distribution networks, as no wheeling fee has been formally approved and no official templates for wheeling agreements with DisCos. This gap is part of the scope of the ongoing technical assistance programs between the Ministry of Electricity and multiple European international development agencies.

Parameter	Net-Metering (active)	Wheeling (inactive)
Location	Generation of electricity is on-site	Generation of electricity is off-site
Technology	Applies only to solar energy	Applies to solar and wind energy
Max. Capacity	25 MW cumulative for projects OR 20 MW per project	No cap on generated electricity
Cash Reconciliation	Cash reconciliations are done at the end of June	Cash reconciliations are done at the end of the contractual year
Price of Reconciliation	Cash reconciliations are done at the last price paid by EETC to a solar power producer	Cash reconciliations are done at the weighted average price of renewable energy power plants owned by New and Renewable Energy Authority (NREA)
Wheeling Fee	None, however there is an integration fee	Yes
Number of Offtakers	Limited to one corporate offtaker	Can have more than one corporate offtaker
Offtake Agreements	Signed by the corporate offtaker	Signed by the IPP itself

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