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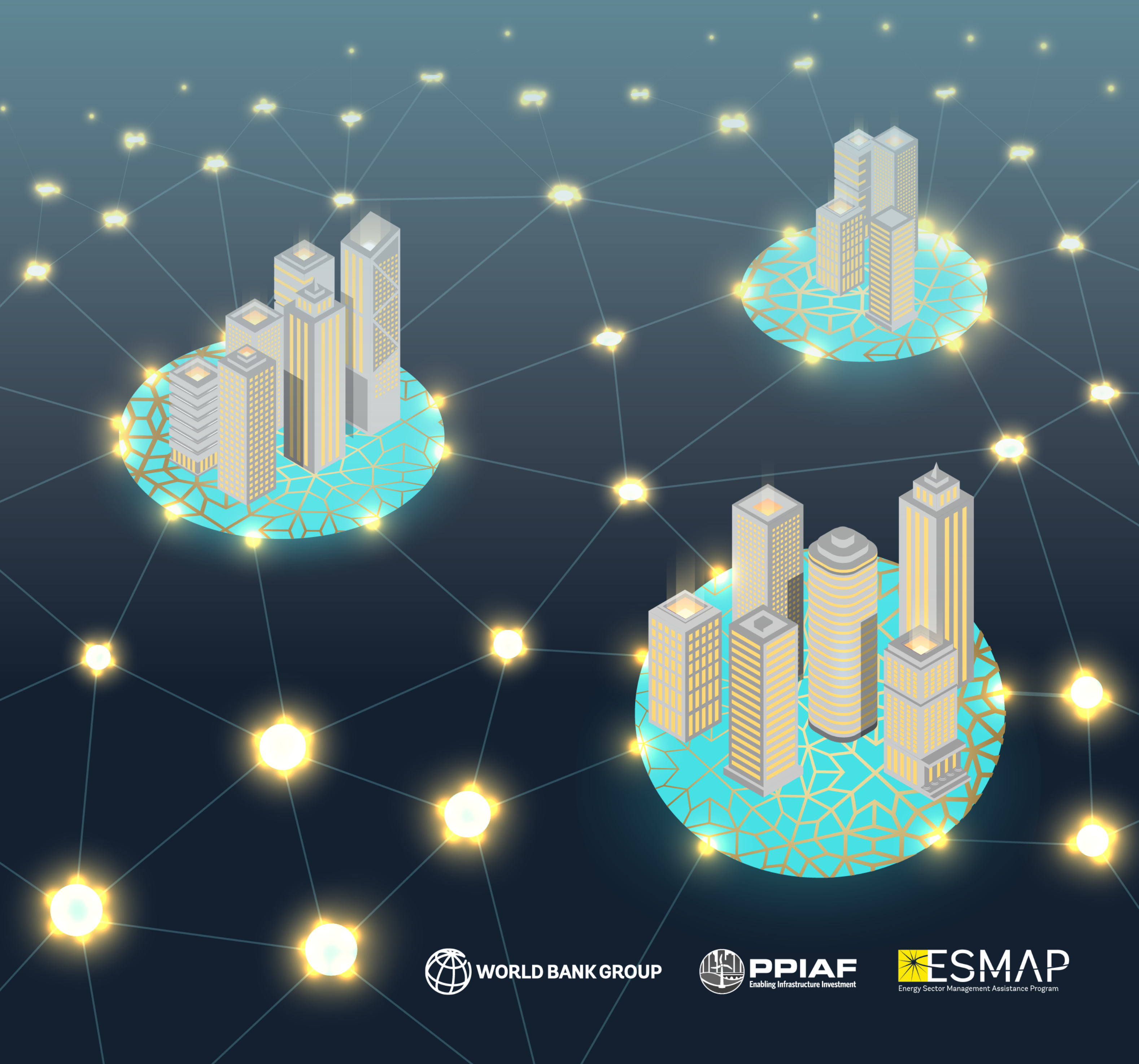
THE VALUE OF TRADE AND REGIONAL INVESTMENTS IN THE PAN-ARAB ELECTRICITY MARKET

INTEGRATING POWER SYSTEMS & BUILDING ECONOMIES

OCTOBER 2021



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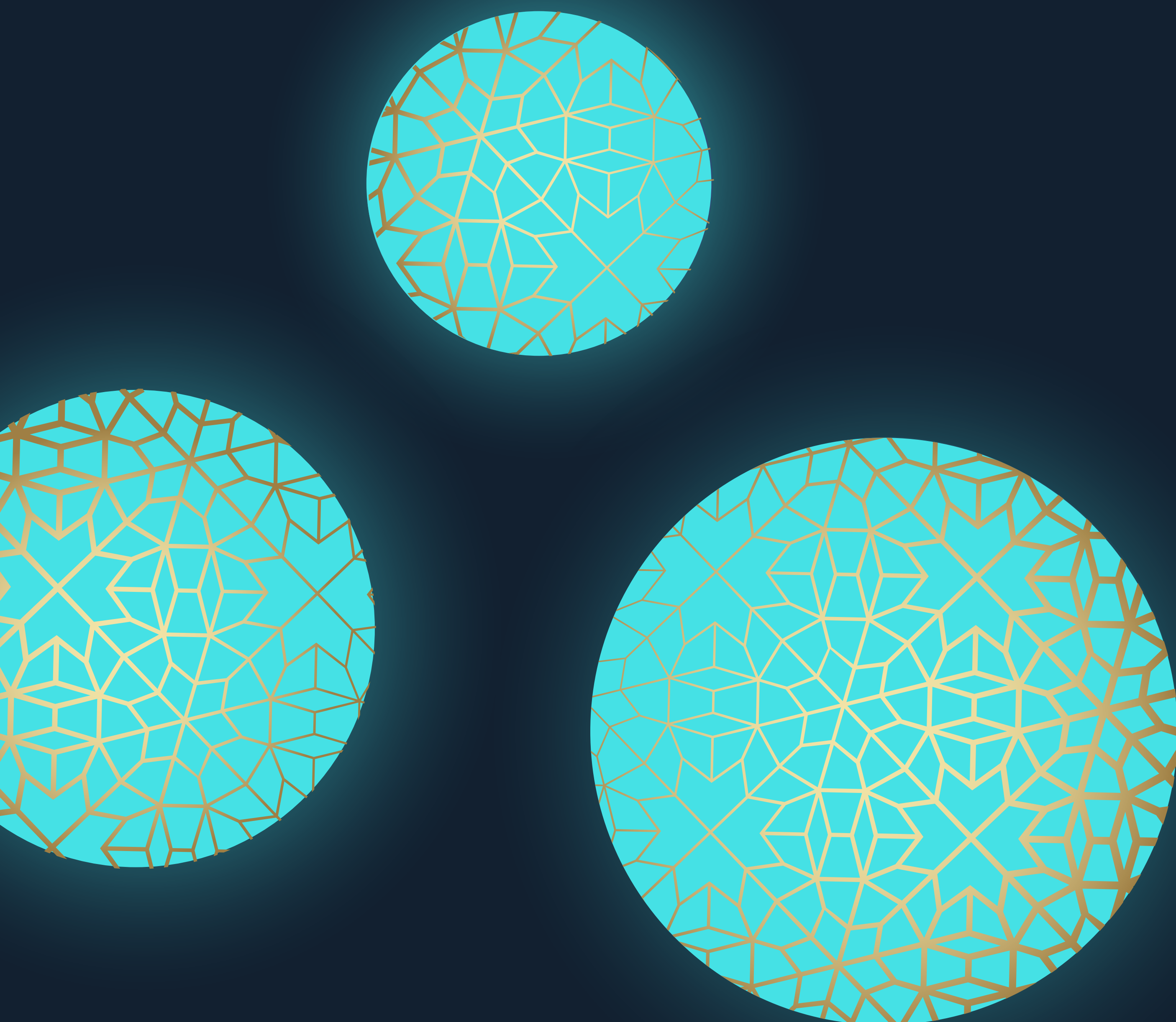

PREFACE

Energy demand in Arab countries continues to grow at a higher rate than economic growth. Meeting national electricity demand and exploiting their significant renewable energy resources (particularly, solar and wind) in a sustainable manner is a common challenge across all Arab countries. A number of analyses have pointed out that such countries would benefit greatly from the increased integration of their power systems, and the resulting opportunities for electricity trade.[1]

The prospects of regional electricity trade in Arab countries have been the focus of a number of studies in recent years. While the potential economic and technical benefits of trade are substantial, so are the challenges, necessitating a political will supported by a shared vision for regional electricity trade. Related plans would do well to be aligned with national goals and to put forward objectives, outline key trade drivers, and identify milestones and their timing.

This study, **The Value of Trade and Regional Investments in the Pan-Arab Electricity Market: Integrating Power Systems & Building Economies (VOTRI)**, quantifies the potential economic benefits that a Pan-Arab Electricity Market (PAEM) could bring if the countries[2] across the Middle East and North Africa (MENA) were engaged in full electricity trade on a commercial basis. The World Bank's **Electricity Planning Model (EPM)** was used to prepare the region's least-cost capacity expansion and dispatch scenarios optimizing the regional power systems in the period 2018–35.

The EPM, details of which are described in appendix F, demonstrates there are direct, sector-level gains from being able to efficiently develop and deploy generation assets at a regional level and optimize cross-border economic power trade (instead of each country developing its own generation resources). Such optimization approach is in line with the PAEM vision. These benefits include increased access to lower-cost, more efficient, and cleaner generation alternatives in an expanding market that can meet export as well as domestic electricity demand.

The long-term vision is that the PAEM will be created in five stages that lead to a fully integrated market in 2035 and a fully competitive wholesale market in 2038. This study outlines the first stage of market development and paves the way for early operations of the market in the second stage, along with priority investments to maximize the realization of electricity trade benefits across the PAEM.

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[1] It is important to note that this study was completed before the COVID-19 pandemic was declared by the World Health Organization (WHO), and it was set to be released following the Arab Ministerial Council for Electricity (AMCE) extraordinary meeting planned in March 2020 to approve the PAEM agreements ratification. However, this meeting was moved to July 2020 due to the pandemic and, therefore, the study was not released. Despite the change in the meeting date, agreements were ratified and recommendations stated in this report are still relevant and timely.

[2] In this study, the term "Pan-Arab countries" refers to 17 countries located across MENA–Algeria, Bahrain, Egypt, Iraq, Jordan, Saudi Arabia, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Sudan, Syria, Tunisia, the United Arab Emirates, and Yemen–plus the West Bank and Gaza. Countries' data were shared and gathered during and between four consultations: in Kuwait City, Kuwait, in November 2017; in Tunis, Tunisia, in March 2018; in Rabat, Morocco, in September 2018; and, in Algiers, Algeria, in January 2019. The countries that provided complete or partial data were Algeria, Bahrain, Iraq, Jordan, Kuwait, Libya, Morocco, Qatar, Saudi Arabia, and Sudan. For those countries missing model parameters, inputs were estimated from publicly available annual reports, online articles, and other sources.

ACKNOWLEDGEMENTS

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The World Bank's Pan-Arab Regional Energy Trade Initiative was incorporated by the World Bank's Middle East and North Africa (MENA) Climate Action Plan, where it contributes specifically to commitment no. 5—enabling collective action. The initiative is also in line with the World Bank's new MENA regional strategy, where it is an essential part of the focus on regional cooperation.

The team is grateful to its regional management (inter alia, Anna Bjerde and Stefan Koeberle, Directors, Strategy and Operations, MNAVP; Sajjad Shah-Sayed, Manager, MNADE; and Deborah Wetzel, Director, AFWRI) and to its global practice management (Riccardo Puliti, Senior Director; Paul Noumba Um, Regional Director; and Erik Fernstrom, Practice Manager) for their support and funding.

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This publication was initially released at the First Pan-Arab Regional Energy Trade Conference held in Cairo, Egypt, on November 6-7, 2019. The conference was co-organized by the World Bank (with support from PPIAF and ESMAP), the Arab Fund, and the League of Arab States. The conference gathered Arab and international experts and decision makers to exchange experiences—creating momentum, a shared vision, and an action plan for regional energy trade and partnerships in both electricity and gas.

Special acknowledgment — The task team wishes to acknowledge the generous funding provided for this report by the Public-Private Infrastructure Advisory Facility (PPIAF). PPIAF is a multi-donor trust fund housed in the World Bank Group that provides technical assistance to governments in developing countries. PPIAF's main goal is to create enabling environments through high-impact partnerships that facilitate private investment in infrastructure. For more information, visit www.ppiaf.org.

The financial and technical support by the Energy Sector Management Assistance Program (ESMAP) is gratefully acknowledged. ESMAP is a partnership between the World Bank and 19 partners to help low and middle-income countries reduce poverty and boost growth through sustainable energy solutions.

ESMAP's analytical and advisory services are fully integrated within the World Bank's country financing and policy dialogue in the energy sector. Through the World Bank Group (WBG), ESMAP works to accelerate the energy transition required to achieve Sustainable Development Goal 7 (SDG7) to ensure access to affordable, reliable, sustainable and modern energy for all. It helps to shape WBG strategies and programs to achieve the WBG Climate Change Action Plan targets.

The report was edited by Fayre Makeig and Stephen Spector. It was designed by Nursena Acar.

ABBREVIATIONS

AC	alternating current
AUE	Arab Union of Electricity
CO_2	carbon dioxide
CSP	concentrating solar power
EIJLLPST	Egypt, Iraq, Jordan, Libya, Lebanon, West Bank and Gaza, Syria, and Turkey
ENTSOe	European Network of Transmission System Operators for Electricity
EPM	Electricity Planning Model
EU	European Union
EWA	Electricity and Water Authority *(Bahrain)*
GCC	Gulf Cooperation Council
GCCIA	Gulf Cooperation Council Interconnection Authority
GW	gigawatt
HVAC	high voltage alternating current
HVDC	high voltage direct current
IEA	International Energy Agency
INDCs	intended nationally determined contributions
ISCC	integrated solar combined cycle
LAS	League of Arab States
LNG	liquefied natural gas
MMBTU	million British thermal units
MW	megawatt
MWh	megawatt-hour
O&M	operations and maintenance
OECD	Organisation for Economic Co-operation and Development
OHTL	Overhead Transmission Line
PAEM	Pan-Arab Electricity Market
PA-REPT	Pan-Arab Regional Energy Trade Platform
PV	solar photovoltaic
SAOC	Oman Electricity Transmission Company
SIEPAC	Central American Electrical Interconnection System
TWh	terawatt-hour
USE	unserved or unmet energy
USR	unserved reserve
VoLL	value of lost load
VRE	variable renewable energy

Note: Economic and financial calculations expressed in US dollars refer to the US dollars (US$) of 2018.

EXECUTIVE SUMMARY

"The Value of Trade and Regional Investments in the Pan-Arab Electricity Market: Integrating Power Systems & Building Economies" (VOTRI), presents a compelling economic case for the increased integration of power systems among the Arab states to advance commercial cross-border electricity trade. A Pan-Arab Electricity Market (PAEM)[3] operating across the Middle East and North Africa (MENA) would bring significant value to the treasuries, utilities, and citizens of the region. This value comes at a critical time, when energy demand far exceeds economic growth.[4] Many of the region's utilities are under financial strain and find themselves unable to invest in new infrastructure at the levels required to meet growing demand. Meanwhile, some countries realize that they have overinvested in supply and will soon have a supply glut after meeting domestic demand.

In 2015, the region's fiscal deficits averaged 9.3 percent of gross domestic product, and the economies with the largest deficits were also those with the highest levels of electricity subsidies. As economies adjust to their present fiscal situation, there will be a scarcity of financing available for the electricity sector.[5] This implies a need to find sources of financing other than the public sector to support infrastructure investments that keep pace with increasing demand. The savings and benefits derived from electricity trade present a strategic opportunity for treasuries and utilities to ease their financial burdens, and best leverage their existing assets in case of a surplus.

A number of detailed technical studies have made the case for regional economic integration, demonstrating the value of cross-border connectivity and the enhancement of electricity trade and investment opportunities. Over the past few years, several key drivers have started to reshape the global energy landscape and motivate countries' transitions to cleaner energy. In particular, a low-carbon energy mix has become a priority in many countries; technological advances—enabled by generous financial support and mandatory requirements—have led to dramatic drops in the cost of renewable energy, especially wind and solar energy; the Paris Agreement on climate change was adopted in late 2015 by 196 countries and formally ratified in 2016; and there has been a scale up of energy subsidy reform programs across the Middle East and North Africa.

In this context, the purpose of this report is to build on previous studies and assess the implications of various drivers for electricity trade in the PAEM. In particular, this report seeks to (i) assess the benefits of promoting electricity trade among countries in the Pan-Arab region; and (ii) identify the cross-border transmission investments promising the greatest return in terms of these benefits.

The identified economic benefits from electricity trade consist of deferred new generation capacity investments due to the improved utilization of capacity resources across the region; fuel savings obtained by new renewable energy production and accessing lower fuel-cost generation from other countries in the region; and greater opportunity to meet capacity and energy reserve requirements at lower cost.

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[3] For the purposes of this study, the integration of 18 electricity markets across MENA is considered: Algeria, Bahrain, Egypt, Iraq, Jordan, Saudi Arabia, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Sudan, Syria, Tunisia, the United Arab Emirates, the West Bank and Gaza, and Yemen.

[4] The fast-emerging plan to build the PAEM to advance electricity trade across the Arab countries has been given even greater urgency by the dual crisis of COVID-19 and the oil price collapse. Electricity is one of the critical sectors that will help revive the Arab economies when they start to reopen and rebuild. Electricity trade has the potential to play a key role in those stages.

[5] Shortage of financing from the oil price collapse has been amplified by the COVID-19 pandemic, leading to significant austerity measures implemented across the Arab world and delaying power generation projects.

KEY CHALLENGES TO ADVANCE ELECTRICITY TRADE IN THE REGION

Electricity trade among the Arab countries has historically been very low. Despite the fact that considerable cross-border interconnection capacity exists, only 2 percent of electricity produced in the MENA region is traded. The Gulf Cooperation Council (GCC) subregion is the most interconnected (compared with the Mashreq and Maghreb subregions).[6] Still, barriers such as an uneconomical pricing framework constrain trade volumes and leave market participants to prefer exchanges "in-kind" (that is, electricity for electricity) rather than for cash, and to focus on emergency operations. Also, utilization of existing interconnection capacity is quite low, at 5 to 7 percent on average. Achieving higher volumes of electricity trade in the region requires addressing the following core challenges.

- **Countries need to develop and agree on a pricing approach** suitable for cross-border trade and transmission "wheeling"[7] on a commercial basis. Removing domestic subsidies on the fuel for power generation in each country engaged in cross-border trade is the key solution in the long term. Applying international fuel prices specifically to cross-border transactions without eliminating subsidies at home is a possible interim solution in the early phases of the regional market. However, countries are encouraged to accelerate the phasing out of these subsidies to fully exploit the potential of trade.
- **Regional institutions for power trade need to be established and empowered** within a common framework that ensures efficient coordination. The development of regional institutions can build on current experience in the region. Governments would benefit by establishing designated and authorized national entities to institutionalize electricity trade in close coordination with the regional institutions envisaged under the PAEM governance framework. Governance documents, including the PAEM General Agreement and the Market Agreement, will form the legal basis for the institutions and the market they will support.
- **Harmonized regulations of cross-border trade need to be developed.** The PAEM would establish needed market rules and grid codes (or technical requirements for different technologies and system configurations), with the understanding that Member States will advance needed reforms in their own territories at their own pace. Eventually, harmonized regulations will play a key role in realizing the ultimate PAEM's vision of a competitive market.
- **Mobilizing finance for investment in generation and transmission assets is also needed.** This is best prioritized within a coordinated regional planning framework that optimizes the investments and operations at the PAEM level and allows participating countries to meet domestic demand in cost-effective and efficient ways.

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[6] In this study, we refer to the Mashreq subregion as comprising eight countries/economies: Egypt, Iraq, Jordan, Lebanon, Libya, West Bank and Gaza, Sudan, and Syria.

[7] Wheeling is the transportation of electric energy (megawatt-hours) from within an electrical grid to an electrical load outside the grid boundaries (https://en.wikipedia.org/wiki/Wheeling_(electric_power_transmission)).

ANALYTICAL FRAMEWORK

The study explores a number of scenarios, or cases, each assuming a different set of economic and policy conditions. The period of analysis is 2018–35. To estimate the economic benefits of regional electricity trade, each case that assumes the possibility of trade (Cases 1, 3, and 5) has a complement case that assumes no such possibility (namely, Cases 0, 2, and 4, respectively), with three pairs of scenarios in all. In addition to the above cases, a demand-side policy scenario (Case 6) was added to study the impact that lower demand growth would have on electricity trade.

The economic benefits of trade are calculated as the difference in system costs estimated for each pair (that is, with and without trade). The study considers cross-border power trade via both existing and planned interconnections.

Although the three pairs of scenarios assume largely similar physical infrastructure, they differ in terms of the policies that underpin cross-border trade:

- The first pair (Cases 0 and 1) assumes that natural gas in participating countries would be priced at its current, subsidized levels.
- The second pair (Cases 2 and 3) assumes that all countries price domestic gas at international[8] levels using European Union Hub prices as a proxy (i.e., unsubsidized gas prices).
- The third pair (Cases 4 and 5) assumes the setting of carbon dioxide (CO_2) emission limits in addition to a switch to international gas prices.

KEY FINDINGS

REQUIRED GENERATION CAPACITY DECREASES WITH TRADE

Electricity trade decreases the total generation capacity required in the region. By 2035, Case 1 installs 11 GW less capacity relative to Case 0; Case 3 adds 15 GW less capacity relative to Case 2; and Case 5 saves as much as 63 GW relative to Case 4. In the demand-side policy scenario (Case 6) the reduction in generation capacity is significant compared to all trade scenarios in Cases 1, 3, and 5. Table 1 illustrates the total cumulative capacity additions, in GW, by technology and total investment cost.

Table 1. Capacity Additions and Investment Costs

	Case 0	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CC	237	230	200	186	210	199	147
CSP	1	0	1	0	161	98	0
GT	27	17	24	14	17	11	12
Hydro	1	1	1	1	3	3	1
PV	65	61	61	63	57	58	53
ST	1	-	1	-	1	1	-
Wind	13	25	37	41	46	47	25
Nuclear	3	2	40	47	48	63	23
Coal	13	13	13	13	11	11	13
Total (GW)	361	350	379	364	553	490	274
Investment (US $billion)	263	252	366	368	745	625	253

Note: CC = combined cycle; CSP = concentrating solar power; GT = gas turbine; Hydro = hydroelectricity; PV = photovoltaic; ST = steam turbine; GW = gigawatt.

TRADE BRINGS REGIONAL POWER SYSTEM COST SAVINGS

Regional integration and electricity trade can lead to massive cost savings. The region could

[8] Due to the lack of a global market price for natural gas, international gas prices are set to the estimates and projections of the trading hub closest to the region, in this case the European Union (EU) Hub.

see tremendous benefits from tapping into a more diverse set of resources and pooling the operating reserves as well as generation capacity of more than one country. This allows the postponement of some expensive investments to meet national-level peak demand, while improving reserve margins, contributing to better security of supply.

When natural gas is priced at current domestic levels, the total system costs decrease in present value terms by **US$110 billion** with the introduction of electricity trade, or by 8.2 percent of the system cost absent trade. Similar savings due to trade are achieved in the scenarios with unsubsidized (international) gas prices, in which case the total system costs decrease by **US$107 billion**. When the liberalization of gas prices is accompanied by the introduction of carbon caps in line with countries' intended nationally determined contributions, the benefits of trade are even greater, reducing the system costs by **US$196 billion**, or by 13 percent.

Finally, with demand-side (energy efficiency) policies assumed to gradually lower electricity demand (by 0.5 percent in 2020, 10 percent in 2025, and 20 percent in 2030–35), the system costs decrease by **US$107 billion,** or about 9 percent, relative to the scenario with trade under international gas prices but without demand-side policies.

A large part of the trade benefits can be attributed to the ability of an integrated system to better meet each country's demand and capacity reserve requirements. The composition of benefits varies greatly across the policy scenarios. With regional integration and trade, the costs of meeting reserve requirements fall especially sharply as trade enables greater access to reserves through cross-border transmission interconnections. The other cost-saving components differ by scenario. For example, there are large fuel cost savings due to electricity trade under both current and international gas prices, but not under carbon caps. On the other hand, much more capital expenditure is saved due to trade with carbon caps than without them.

NATURAL GAS PRICES SIGNIFICANTLY AFFECT TRADE

Adopting international gas prices would help ensure that generation technologies are competing on a level playing field. While the switch from current gas prices to international prices leads to higher installed capacity requirements and higher capital costs, the fuel cost savings more than offset these when the costs of gas subsidies are taken into account. Also, renewable technologies are deployed at a higher rate under international prices as they are more competitive under nondiscriminatory market conditions.

Moreover, using international gas prices leads to reductions in carbon emissions. If the CO_2 emissions under the case of using these prices are compared with those under the current domestic prices, the emission savings amount to 1.08 billion tons of CO_2 equivalent when there is no trade, and to 1.24 billion tons when there is trade (cumulative over 2018-35).

IMPACT ON ELECTRICITY SUPPLY COSTS

The effect of trade on cost of electricity would vary across the region. The introduction of electricity trade would impact electricity costs differently in each country context. Many countries—mostly those with substantial generation gaps or low resources—could expect to see reductions. In some countries, the impact of trade on electricity costs would be marginal. In countries that are net exporters, the cost of electricity would increase. These are mainly gas exporters that have an incentive to invest more in generation capacity due to their ability to generate electricity at lower cost. However, as they install more generation capacity, the cost of electricity also rises as their effective demand, including export requirements, rises. They may need to utilize existing generators that would not otherwise be utilized without trade, or even to invest in progressively higher-cost generation technologies.

TRADE UNLOCKS RENEWABLE ENERGY POTENTIAL AND REDUCES CO_2 EMISSIONS

Carbon policies that regulate emissions will be required in addition to trade to meet the region's emissions reduction targets. The impact of power system integration and trade on the region's CO_2 emission trajectory was found to be moderately positive (that is, leading to moderate reductions in CO_2 emissions relative to cases with no trade). However, this impact is less pronounced than that of the other key variables, such as the level of gas prices or the introduction of CO_2 emission limits. With gas prices at current levels, the CO_2 emission reductions due to trade are almost negligible. The reductions become more significant when the gas prices are set at the EU Hub as a proxy. When CO_2 emission caps are also introduced, the impact of trade decreases again, but the additional emission savings due to the caps are striking: 1.3 billion tons of CO_2 without trade and about 1.1 billion tons with trade. Trade also decreases the cost of compliance with CO_2 emission targets, indicating the synergies existing between trade and the intended nationally determined contributions (INDCs) published by the Pan-Arab countries after the 21st Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change.

The dynamics of CO_2 emissions are driven to a large extent by the changing mix of generation technologies. By 2035, the share of zero-emission renewable energy technology in the region is expected to increase dramatically, albeit starting from a very low base (1.4 percent in 2018). In the six cases considered, the share of renewable energy (wind, solar photovoltaic, and concentrating solar power) in total installed capacity in 2035 reaches anywhere from 14.5 percent (Case 0) to 18.1 percent (Case 3) to 32.7 percent (Case 4).

INVESTMENTS IN CROSS-BORDER INTERCONNECTION TO UNLOCK ELECTRICITY TRADE POTENTIAL

Investments in cross-border transmission infrastructure are necessary to fully exploit the potential benefits of regional electricity trade by unlocking the trade opportunities beyond bilateral agreements. Under current assumptions for all the cases analyzed in this study, the lines that would be consistently utilized over 50 percent during the analysis period 2018-2035 are:

- Algeria ⇆ Tunisia
- Egypt ⇆ Sudan
- Jordan ⇆ Egypt
- Libya ⇆ Tunisia
- Saudi Arabia ⇆ Egypt
- Saudi Arabia ⇆ Jordan
- Saudi Arabia ⇆ Iraq
- Saudi Arabia ⇆ Kuwait
- Saudi Arabia ⇆ Yemen
- Syria ⇆ Iraq
- Syria ⇆ Lebanon
- Gulf Cooperation Council Interconnection Authority (GCCIA) ⇆ Bahrain
- Gulf Cooperation Council Interconnection Authority (GCCIA) ⇆ Kuwait
- Gulf Cooperation Council Interconnection Authority (GCCIA) ⇆ Saudi Arabia

These transmission lines are therefore considered a priority for investments as they play a critical role in realizing the value of trade and overall trade benefits across the PAEM. Developing a comprehensive transmission investment plan that aligns national and regional system requirements is an important next step toward the envisioned PAEM.

To assess the benefits of trade, this study considers 25 transmission investment projects across the region, including 15 projects that reinforce the existing transmission infrastructure and 10 projects of newly built transmission lines. In total, this would add 18.5 GW of cross-border transmission capacity. The initial estimated investment cost for these transmission projects reaches a total of $7.5 billion.

Interconnection Reinforcements

- Algeria ⇆ Morocco, 600 MW
- Egypt ⇆ Jordan, 650 MW
- Egypt ⇆ Sudan, 1,000 MW
- Egypt ⇆ Gaza Strip, 175 MW
- Jordan ⇆ West Bank, 160 MW
- Libya ⇆ Egypt, 370 MW
- 2nd circuit of Libya ⇆ Egypt, 450 MW
- 2nd circuit of Jordan ⇆ Syria, 450 MW
- 3rd circuit of Jordan ⇆ Syria, 200 MW
- Lebanon ⇆ Syria, 730 MW
- Saudi Arabia ⇆ GCCIA Interconnection, 600 MW
- Kuwait ⇆ GCCIA Interconnection, 600 MW
- Qatar ⇆ GCCIA Interconnection, 1050 MW
- UAE ⇆ GCCIA Interconnection, 900 MW
- Bahrain ⇆ GCCIA Interconnection, 600 MW

New Cross-Border Interconnections

- Saudi Arabia ⇆ Egypt, 3,000 MW
- Saudi Arabia ⇆ Yemen, 500 MW
- Tunisia ⇆ Libya, 500 MW
- 2nd Circuit of Tunisia ⇆ Libya, 500 MW
- Saudi Arabia ⇆ Jordan, 1,000 MW
- Saudi Arabia ⇆ Iraq, 1,000 MW
- Jordan ⇆ Iraq, 500 MW
- Oman ⇆ Saudi Arabia, 1,000 MW
- Kuwait ⇆ Iraq, 1,000 MW
- Kuwait ⇆ Saudi Arabia, 1,000 MW

ESTIMATED ECONOMIC BENEFITS FOR MARKET PARTICIPANTS AND COMMERCIAL VALUE OF ELECTRICITY TRADE

In addition to the above main method for estimating the benefits from trade and investment in the MENA region, based on total system cost savings, two alternative metrics have been also evaluated in this study. They point, respectively, to large benefits to be gained and shared by trading partners through bilateral transactions; and similarly large export and import values to be exchanged in the market, contributing to its liquidity.

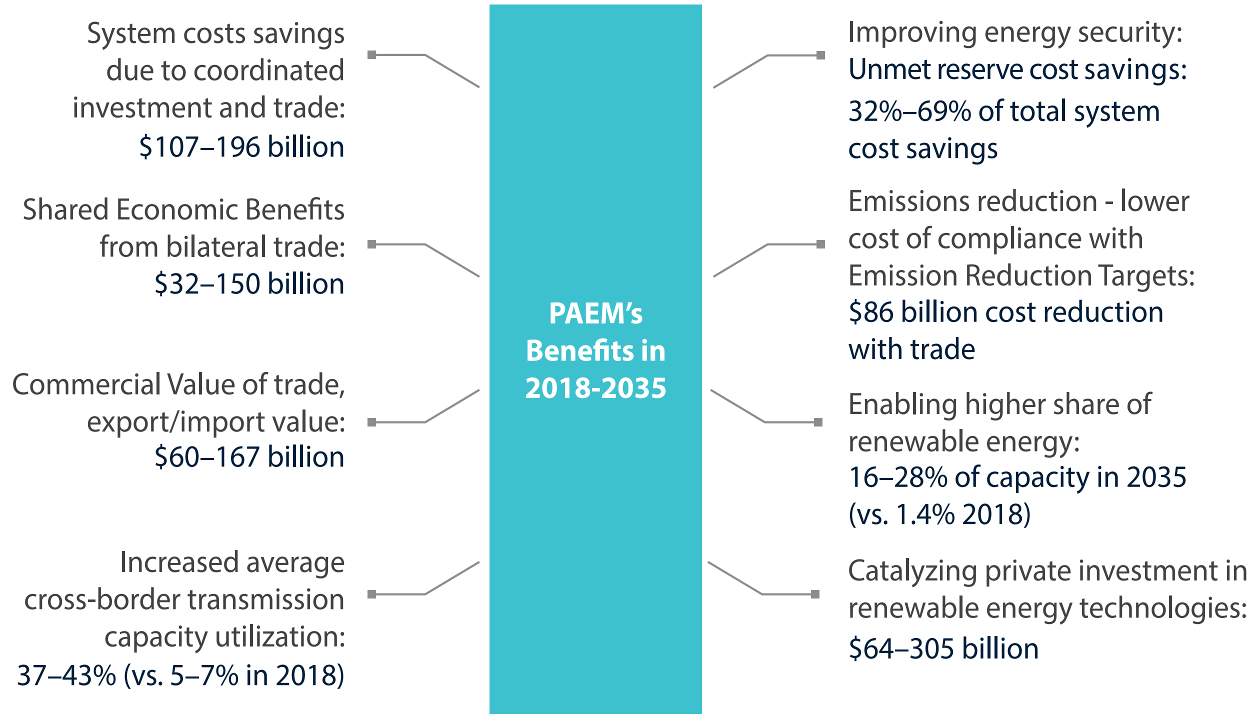
Economic benefits based on generation cost differentials that exist in many country settings across the region are very substantial and can be shared by trading countries. For three main cases with trade, these benefits are between US$32 billion (Case 3, international gas prices) and US$150 billion (Case 5, international gas prices and carbon caps).

Commercial value of trade, a financial metric measuring the potential volume of export and import transactions in the market, has the same order of magnitude. The calculated values range between US$60 billion (Case 1, current natural gas prices) and US$167 billion (Case 5).

Increasing the existing cross-border interconnections' utilization, in the period 2018–35, results in an estimated US$72 billion in total system cost savings and US$23 billion in commercial value of trade. Investing in regional cross-border transmission projects to add a total of 18.5 GW of new or reinforced interconnectors to the regional network would increase total system cost savings by US$35 billion (to a total of US$107 billion, for Case 3) and the commercial value of trade by US$39 billion (to a total of US$62 billion, for Case 3) at a cost of US$7.5 billion. This indicates that investing $1 to expand regional cross-border trade saves $4.6 in total system costs and increases the commercial value of trade by $5.10 (in Case 3).

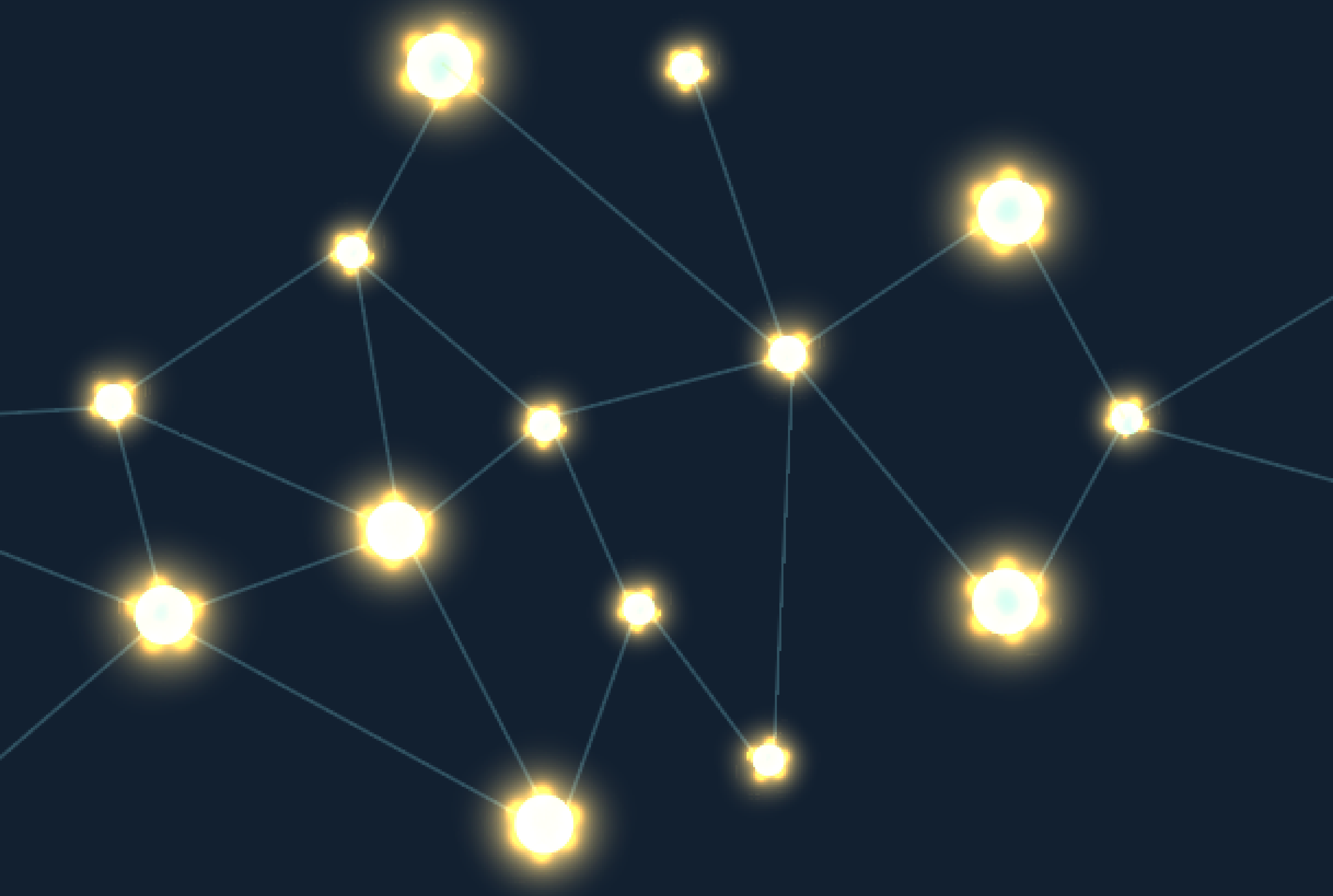
Finally, figure 1 provides a summary of potential electricity trade benefits across the PAEM in 2018–2035 based on the analyzed cases and cross-border transmission investments.

Figure 1. Potential Electricity Trade Benefits (2018–35)



Source: World Bank modeling results

1 STRATEGIC CONTEXT



Starting from its significant update in 2015 (WBG 2015), the World Bank Group's regional strategy in the Middle East and North Africa (MENA) builds on the platform of advancing peace and stability directly, as a new area of engagement, rather than working around conflict as an inevitable reality. This strategic shift has required deepening partnerships and convening more with regional partners, pushing more strongly for private investments, focusing more on regional programs in key sectors, including energy, and applying innovative financing mechanisms to attract capital from a more diverse pool of sources.

Regional cooperation has been established as one of the four strategic pillars of the Bank's engagement in MENA (see box 1). Regional integration of infrastructure and markets is key to establishing such cooperation.

Box 1. The World Bank's Regional Strategy in the Middle East and North Africa

The four fundamental pillars ("4 Rs") underpinning the scope of the World Bank Group's engagement in the Middle East and North Africa region have been established as: (a) renewal of the social contract; (b) resilience to shocks, including those due to refugee crises and climate change; (c) regional cooperation; and (d) recovery and reconstruction. The focus on these fundamentals was further enhanced by enlarging the strategy in 2019 to support regional transformation for inclusive growth and quality jobs. The strategy, therefore, was strengthened by adding three more priorities, namely: human capital development; digital development; and maximizing finance for development.

Source: WBG 2015, 2016a, 2017a, 2018a, 2019a.

Furthermore, **regional integration is seen as a transformative force.** After the 2011 Arab Spring and various additional shocks that followed, the region entered a period of relative stability—but conflicts remain across the region. The enlarged MENA regional strategy (WBG 2019a) calls on the region to move ***from stabilization to transformation***, while keeping a focus on the fundamentals.

The energy sector plays a key role in the regional strategy. Throughout its recent updates (WBG 2015, 2018a, 2019a), the energy sector has been one of the strategy's key elements. This reflects the sector's great significance as:

- A key driver of economic growth and thus an integral part of the World Bank's twin goals— reducing poverty and promoting shared prosperity
- A critical element of the World Bank's commitment to the United Nations Sustainable Development Goals (see table 2)
- A significant arena of technological transformation, with attendant risks and opportunities for the region's fossil-fuel-dependent economies
- A sector requiring substantial structural reform in many countries, including pricing/subsidy reforms, to restore macroeconomic and fiscal balances and attract private investment
- A significant contributor to regional economies that is historically falling behind its great potential for regional integration
- A major component of climate change mitigation measures across all countries, particularly for those which submitted their Intended Nationally Determined Contributions after the 21st Conference of the Parties (COP21)

Regional trade in electricity, as well as in natural gas, can become a transformative force for market integration and sustainable development. In the Arab countries, there are great potential benefits from increasing electricity and gas trade beyond their current levels.

Table 2 shows that there are many areas in the region's energy sector development where a transformational impact can and should be achieved in order to reach the Sustainable Development Goals. One area requiring radical transformation is renewable energy, whose deployment is at a very low level across the

Table 2. Obstacles to Meeting the Sustainable Development Goals in MENA

SDG Name	SDG Objective(s)	Salient Issues/Challenges in MENA
SDG 7: Affordable and Clean Energy	Ensuring access to affordable, reliable, sustainable and modern energy for all	High energy access rates and affordability, but significant challenges with energy security and environmental sustainability: - High energy intensity and the dominance of fossil fuels contribute to high GHG emissions - Renewable energy contributing only about 1% of the total energy mix
SDG 8: Decent Work and Economic Growth	Promoting sustained, inclusive, and sustainable economic growth, full and productive employment and decent work for all	-GDP growth has been below the global average in recent years, at a modest 1.7 percent in 2018 and forecast at 2.7 percent in 2021 - Unemployment rates are high, especially among women - Opportunities for large youth population are constrained by lack of access to quality internet and digital money
SDG 9: Industry, Innovation, and Infrastructure	Building resilient infrastructure, promoting inclusive and sustainable industrialization and fostering innovation	Enormous capital needs for infrastructure (about US$2.5 trillion over the period of 2016–2030), leaving infrastructure financing gaps in countries, including 0.9% of GDP in Saudi Arabia
SDG 13: Climate Action	Urgent action to combat climate change and its impact	- On the mitigation side, urgent action is needed for phasing out energy subsidies, higher energy efficiency and reduced gas flaring and scaling up investment in renewables (including through cross-border market integration). - The region is very vulnerable to climate change, calling for mobilizing large funds for adaptation projects.

Source: WBG 2018b; WEC 2017; MGI 2016.
Note: GDP = gross domestic product; GHG = greenhouse gas; MENA = Middle East and North Africa; SDG = Sustainable Development Goal.

region. A much greater role for renewables is now possible, given that their installed costs per kilowatt are steadily falling worldwide. However, subsidized prices for electricity produced from fossil fuels make it difficult for renewable energy to compete.

Generation fuel price subsidies, which are widespread in the MENA region, have several undesirable effects. First, they promote inefficient consumption decisions, leading to inefficient allocation of resources and unnecessary stress on the environment. Increased energy consumption results in increased energy infrastructure needs and increased risk of energy supply disruptions. Second, and very important to this study, the underpricing of electricity hampers electricity trade, and in turn leads to increases in the overall cost of energy as countries plan and operate their energy systems from a domestic perspective rather than a more economic regional perspective. Third, subsidies increase the financial burden on governments and utilities: it has been estimated that the region's fiscal deficits averaged 9.3 percent of gross domestic product (GDP) in 2015, and the economies with the largest deficits were also those with the highest levels of electricity subsidies. Lastly, subsidies lead to reduced exploration and development of domestic fuels (that is, oil and gas) because subsidized domestic energy prices are not attractive to investors and developers (WBG 2018c, 2019b).

Recognizing the need to diversify their energy sectors, many countries of the MENA region have launched programs to increase the share of renewable energy in power generation—particularly solar and to a lesser degree onshore wind. This is meant to free up domestically produced hydrocarbons for export, ideally in the form of higher value-added refined or petrochemical products. Particularly where those renewable energy technologies are indigenous or the equipment is domestically produced, they can also help to spur a local technology ecosystem to foster employment (WBG 2019c).

Political difficulties inherent to raising consumer prices and to overcoming entrenched institutional, bureaucratic, and economic interests often impede plans to increase the role of the private sector in generation (and, ultimately, transmission and distribution), to reduce and eventually remove the energy price subsidies on fuel inputs and electricity, and to minimize fiscal pressures on the public budget. As a result, the rate of domestic reform varies across the MENA region (WBG 2019c).

1.1. KEY ENERGY DEVELOPMENTS IN THE MENA REGION

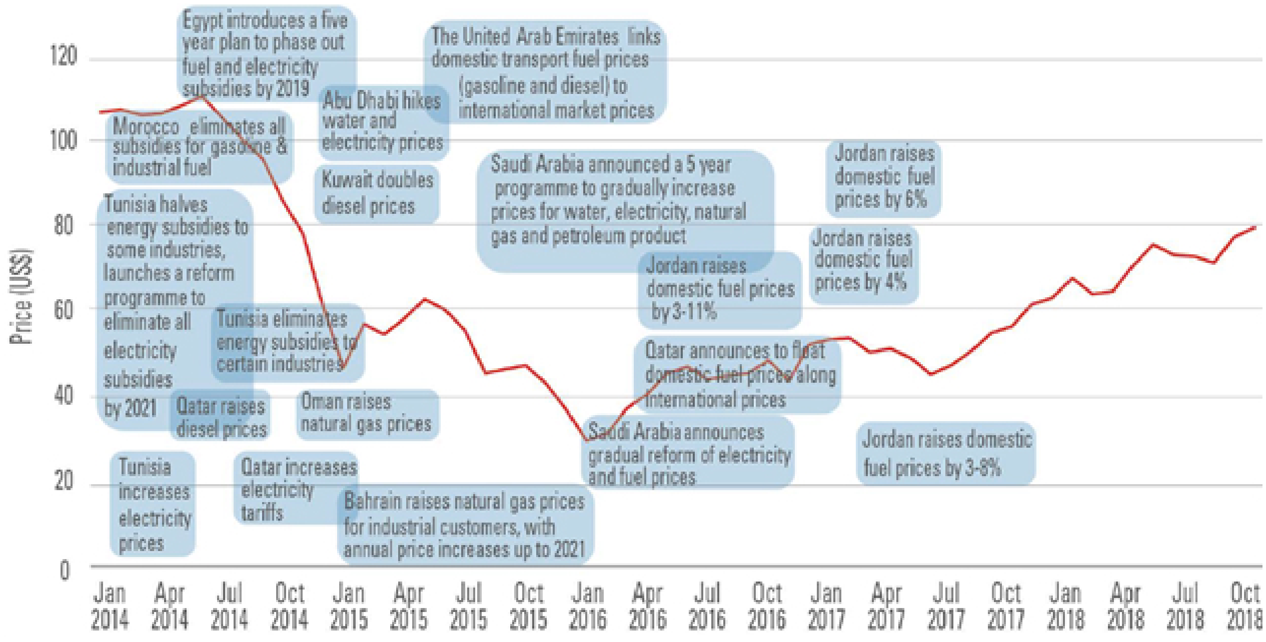
Electricity consumption in the Pan-Arab region[9] has increased tenfold since 1980 as a result of several factors, including population growth, urbanization, industrialization, and the cost of electricity being made artificially low through government subsidies. Although in recent years demand growth rates have decreased, due to weaker economic activity and increases in electricity costs as energy subsidies are reduced, this study estimates that the region will need to add capacity at 6 percent annually until 2025. This corresponds to additions of almost 150 gigawatts (GW), and investments of approximately US$134 billion. Governments continue to tackle this challenge by expediting new projects and upgrading their infrastructure while also encouraging the private sector to join as partners.

Besides continuing to invest heavily and increase the role of the private sector in power generation, Arab countries can also cooperate with one another to further explore the potential of electricity trade as a supplement to their capacity additions. And, although the region must overcome major challenges—such us chronic technical, institutional, and political barriers—recent developments in the region make a strong case for fostering energy trade.

OIL PRICE AND ENERGY PRICE REFORM

Starting in 2014, the onset of persistently low global oil prices, together with dramatic increases in domestic oil consumption, sparked major energy pricing reforms across the MENA region. Since the budgets of several governments in the region heavily depend on oil exports, reduced revenues created pressure to reduce state spending. A number of countries including Egypt, Saudi Arabia, Kuwait, Qatar, the United Arab Emirates, Oman, and Bahrain raised prices on energy products that had long been fixed at very low levels (see figure 2).

Figure 2. Selected MENA Countries' Energy Price Reforms and International Oil Prices



Source: ESCWA 2019 (based on EIA 2018).

[9] This study refers to the "Pan-Arab region" as 17 countries located across the Middle East and North Africa region. These countries are: Algeria, Bahrain, Egypt, Iraq, Jordan, Saudi Arabia, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Sudan, Syria, Tunisia, the United Arab Emirates, and Yemen, plus the West Bank and Gaza.

As fuel subsidies constitute a barrier to electricity trade in the region, raising fuel prices could facilitate cooperation among countries and provide an opportunity for structural reforms.

RENEWABLE ENERGY COST TRENDS

The costs of commercially available renewable energy generation technologies continue to fall and, given the excellent solar and wind resources of the MENA region, these technologies have become a low-cost source of new power generation.

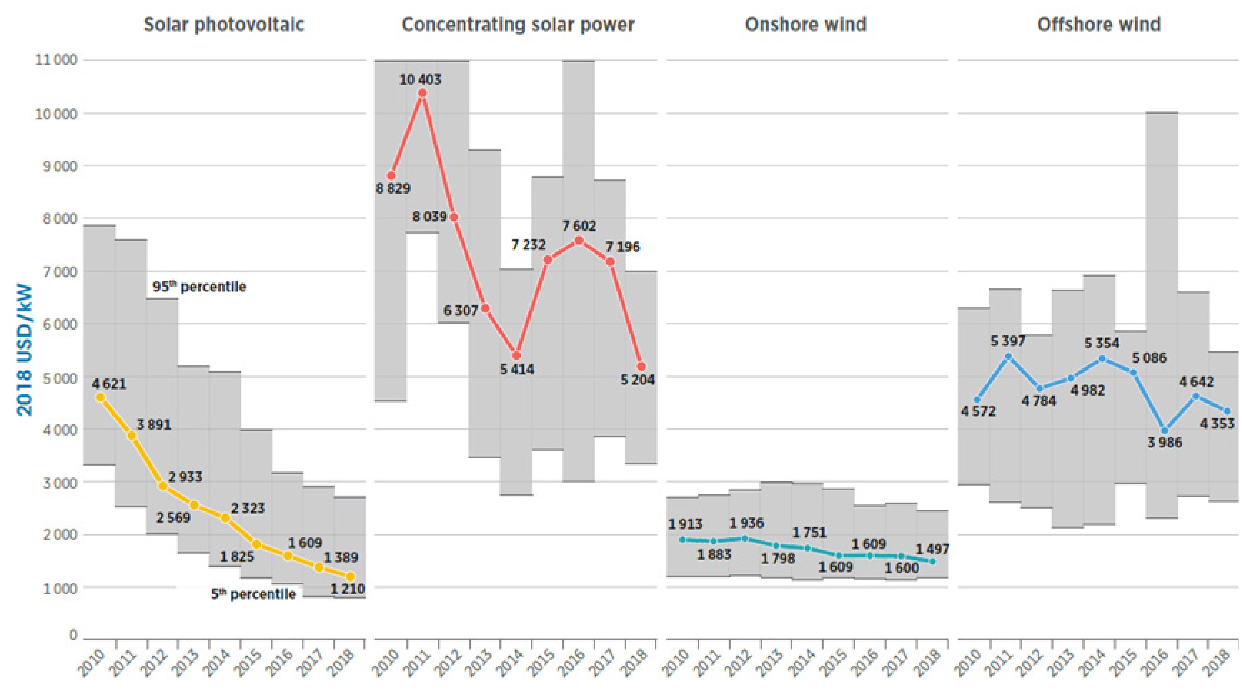
Some of the most relevant declines in installed capacity costs are illustrated in figure 3. The global weighted average total installed cost for utility-scale solar photovoltaic (PV) fell from US$4,621/kilowatt (kW) in 2010 to US$1,210/kW in 2018. Although concentrating solar power (CSP) costs remain high, they experienced a substantial reduction since 2011. By 2018, greater competitive pressures had reduced installed costs to US$5,204/kW, with projects benefitting from greater solar resources. Onshore wind total installed costs fell by an average of 20 percent between 2010 and 2018, as deployment in China and India grew. Offshore wind installed costs remain high as projects move into deeper waters further offshore—raising foundation and installation expenditures.

As the deployment of renewable energy technologies increases throughout the region amid the continued decline of their costs, a focus on facilitating electricity trade creates an opportunity to share domestic renewable resources among countries. This would have substantial economic benefits and also lower carbon emissions.

THE ROLE OF NATURAL GAS

The Pan-Arab region accounts for about 41 percent of the world's proven gas reserves, yet only 16 percent of global gas production. The potential for the future expansion of the gas market, on both the supply and demand sides, is significant. Gas in many Arab countries has become a low-cost source of fuel for domestic industry, a source of revenue for trade transit countries, and a highly valued export commodity to multiple destinations in Asia and Europe.

Figure 3. Global Weighted Average Total Installed Costs and Project Ranges for Solar PV, CSP, and Wind



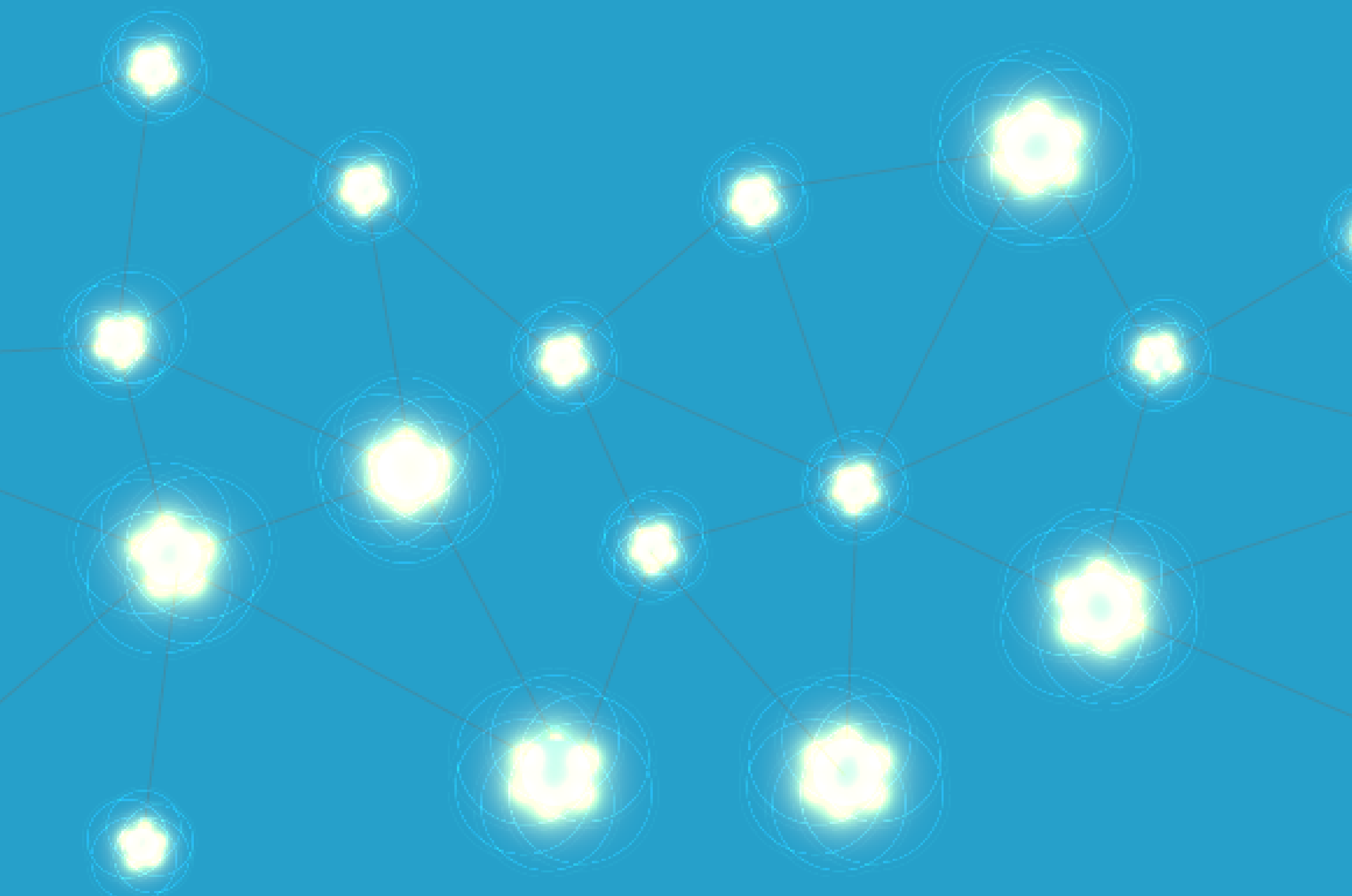
Source: IRENA 2019.
Note: USD/kW = U.S. dollar per kilowatt; PV = photovoltaic; CSP = concentrating solar power.

Countries of the region can play the role of swing producers, taking advantage of their location to supply both Atlantic and Pacific markets.

When compared with other fossil fuels, natural gas burns much cleaner and can also generate electricity on demand. Therefore, natural gas generation technology is capable of both reducing fossil-fuel-based greenhouse gas emissions and paving the way to an emissions-free future, playing a useful part alongside and as a backup for renewable energy sources.

Natural gas could facilitate the transition to sustainable energy systems by improving the economics of renewable-compatible gas power plants and by finding possibilities for natural gas infrastructure to continue operating in a low-carbon world.

2 OVERVIEW AND PURPOSE OF THE REPORT

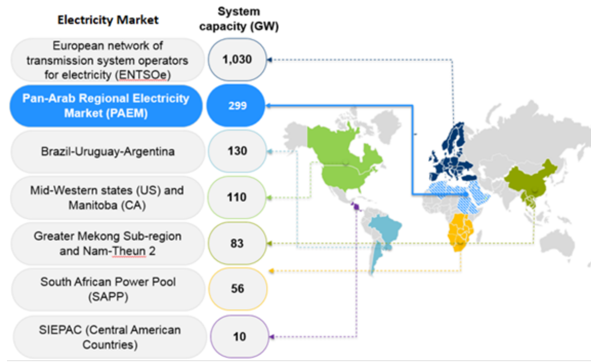


The Pan-Arab region has a significant opportunity to advance its regional and national energy policy goals in a more efficient and integrated way with the introduction of electricity trade as part of a regional power market. Electricity trade within a well-integrated power market promises many benefits, such as enabling access to lower-cost generation resources and fuels, facilitating greater synergy between the different demand and renewable energy profiles among the countries of the region, and increasing the security of electricity supply to meet the region's electricity load.

In cooperation with the League of Arab States, the World Bank developed a governance and institutional framework to establish the Pan-Arab Electricity Market (PAEM). This is supported by the Pan-Arab Regional Energy Trade Platform (PA-RETP), initiated by the World Bank in 2016 to advance the development of electricity and gas trade in MENA. The envisaged governance and institutional framework of the PAEM would help achieve regional integration and the benefits of power trade among the countries in the broad Pan-Arab region. This document is one of the PA-RETP deliverables that was developed in close cooperation with the League of Arab States and its Member States. The analytical model used for the purpose of this document is based on the World Bank's power system planning models and is used to assess the benefits of promoting electricity trade among 18 countries in MENA.

The motivation for the PA-RETP initiative is to enable the MENA region to attain all the benefits of the energy trade seen in other regions around the world. Figure 4 presents some prominent examples of regional energy markets. Using the total generation capacity installed or peak demand to estimate the market size of each region, figure 4 shows that the European Network of Transmission System Operators for Electricity (ENTSOe) is the regional electricity market with the highest generation capacity, at 1,030 GW; and the Central American Electrical Interconnection System (SIEPAC) has the lowest, at 10 GW. With 299 GW of generation capacity installed in its countries by 2018, the Pan-Arab region has the potential to develop into one of the largest regional electricity markets in the world.

Figure 4. Estimated Size of Selected Regional Electricity Markets around the World



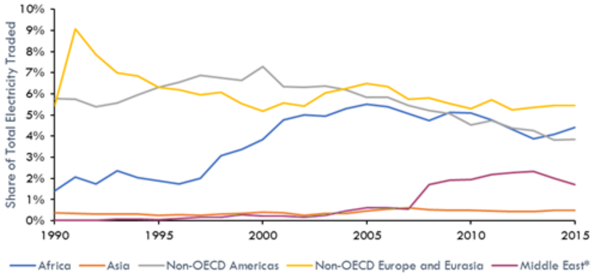
Source: International Energy Agency Database.
Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.
CA = Canada; GW = gigawatt; SIEPAC = Central American Electrical Interconnection System.

2.1. CURRENT STATE OF POWER SYSTEMS IN THE PAN-ARAB REGION

Electricity trade in the Pan-Arab region has historically been very low, despite a relatively high cross-border interconnection capacity (7.7 GW). Only 2 percent of electricity produced in the region is traded in some form. Utilization of the existing cross-border transmission capacity is also quite low (approximately 5–7 percent), and generation capacity is underutilized (approximately 42 percent). Furthermore, the region holds 41 percent of worldwide gas reserves and 20 percent of worldwide gas production, yet only 10 percent of the gas exported by MENA countries is traded in the region. At the same time, electricity demand in the region is expected to double in the 2018–35 time frame.

Figure 5 shows the share of total electricity generated that was exchanged per year, from 1990 to 2015, in regions that were not part of the Organisation for Economic Co-operation and Development (OECD). While Africa, the non-OECD Americas, and the non-OECD Europe and Eurasia regions reached percentages over 5 percent,[10] the Middle East region reached only 2 percent of electricity exchanged regionally in 2008 and remained around that level until 2015. This is the second-lowest share after Asia and lower even than regions with smaller electricity market sizes, such as Africa and Central America.

Figure 5. Share of Total Electricity Traded in Non-OECD Regions (1990-2015)



Source: IEA 2017. *IEA classification of the Middle East region does not include data for Algeria, Morocco, Tunisia and Libya. However, trade among these countries has been historical minimal.
Note: OECD = Organisation for Economic Co-operation and Development.

Countries within the MENA region have taken preliminary steps toward increasing regional electricity exchanges, in the form of bilateral contracts between individual countries and other subregional initiatives. The primary regional interconnection schemes among Arab countries currently include:

- The Maghreb regional interconnection, which includes Morocco, Algeria, and Tunisia. It was initiated in the 1950s and has since evolved into multiple high-voltage transmission interconnections between the three countries. Morocco was later connected to Spain in the late 1990s, and Morocco, Algeria, and Tunisia are now all synchronized with the Pan-European high-voltage transmission network.
- The EIJLLPST (Egypt, Iraq, Jordan, Libya, Lebanon, West Bank and Gaza, Syria, and Turkey) regional interconnection; established by Egypt, Iraq, Jordan, Syria, and Turkey in 1988 as part of an effort to upgrade their electricity systems to a regional standard. Lebanon, Libya, and West Bank and Gaza have since joined, to complete the list of members.
- The Gulf Cooperation Council (GCC) regional power interconnection, which connects six countries in the Arabian Peninsula—Kuwait, Saudi Arabia, Bahrain, Qatar, the United Arab Emirates, and Oman—is based on an agreement signed in 2009; it facilitates electricity exchanges among its members. This interconnection enhances capacity reserves and improves the reliability of supply (WBG 2013). The GCC plans to further expand interconnection to Iraq and the neighboring regions.
- Saudi Arabia's cross-border interconnections plans could advance the integration among the above subregions. These plans include the Egypt-Saudi electricity interconnection project, which is underway and is expected to start operating in 2023, with a capacity of 3,000 megawatts (MW). There are also plans at different stages of maturity to interconnect Saudi Arabia with Jordan, Iraq, and Yemen; as well as with Africa via Ethiopia. The latter complements the current interconnection between Egypt and Sudan, which are both part of the Eastern Africa Power Pool.

Although efforts to increase regional electricity trade within the MENA region have been ongoing for a while, substantial work remains to realize the massive potential of a fully operational regional competitive market within a well-designed governance and institutional framework.

2.2. STUDIES OF PAN-ARAB ELECTRICITY TRADE

Electricity trade in the Pan-Arab region has been the subject of several studies (see appendix A for more details). Most of these focus on a subset of Arab countries, and only one of them employs a formal model to assess the costs of regional policies and scenarios. Those that

[10] Mainly, due to the eastern and southern African power pools (EAPP and SAPP) in Africa and the Central American Power Market (SIEPAC) in the non-OECD Americas.

describe the challenges of enabling electricity trade do so from the perspective of a single country at a time. Also, these studies do not exploit all the synergies between individual country load and renewable energy patterns. But in the real world, capacity expansion decisions must consider the full demand and renewable resource variability (time blocks). While these issues are not relevant in systems with low levels of renewable penetration, they become salient as soon as renewable penetration is significant.

This study builds on this previous work by using a model that explicitly accounts for the following variables:

- The impact of decisions on demand and renewable resources' hourly variability, using an investment model that incorporates hourly resolution data
- Ways that interconnections may be used to operate generators more efficiently and to defer new capacity
- Updated inputs that reflect the latest regional trends
- The need for reserve capacity, in light of the increasingly substantial role of renewables

The main analytical work of the present study is based on results produced by the World Bank's Electricity Planning Model (EPM), which determines least-cost generation expansion plans and optimal use of resources—including both generation and regional interconnections—under various conditions. The EPM is described in more detail later in the report.

2.3. THE PURPOSE OF THE REPORT

This report presents the findings of an analytical study conducted by the World Bank's Global Energy Practice in the MENA region to (i) assess the benefits of promoting electricity trade among countries in the Pan-Arab region; and (ii) identify which cross-border transmission investments promise the greatest return in terms of these benefits.

Since the conclusion of the Paris Agreement in 2015, a number of important developments have taken place, influencing decisions in the Pan-Arab region's power sectors. These include:

- Rapid reductions in the capital costs of renewable energy technologies (mainly, utility-scale solar photovoltaics)
- Changes in the electricity mix, from being dominated by liquid fuel toward using natural gas as a transition fuel
- Electricity tariffs moving towards cost recovery amid energy subsidy reforms
- Increased focus on advancing regional electricity trade as a complement to capacity additions to meet growing demand—mostly driven by a combination of countries with an emerging supply surplus and those where demand is fast outpacing supply

Considering these developments and their effect on the region's power systems, an additional purpose of this report is to revisit the investment recommendations made in previous studies.

The following sections of this report are divided as follows:

- Chapter 3 details the fundamentals of regional power market integration, the development of regional power markets, and the benefits of electric power trade.
- Chapter 4 presents the background of the regional integration of electricity markets in the Pan-Arab region and the challenges it faces.
- Chapter 5 describes the methodology applied to determine the economic benefits of electricity trade and regional-level investments.
- Chapter 6 summarizes the main technical and economic parameters of the existing power generation systems, the projected electric demand, the current status of cross-border interconnections, and the capacity expansion plans for each country included in this study.
- Chapter 7 provides the long-term regional capacity expansion plan results

under six scenarios (described in section 5.2), determines the economic benefit of electricity trade, and presents a sensitivity analysis to demand changes.

- Chapter 8 extends the analysis of the results by proposing an analytical framework to perform a screening and prioritization of electricity interconnection investments.
- Appendices A–H contain further data and documentation that support the main contents of the report.

3 THE FUNDAMENTALS OF REGIONAL POWER MARKET INTEGRATION

Most regions of the world have substantial imbalances among their countries' power systems, such as surplus generation capacity in one country and shortage in another. As a result, opportunities arise for electricity trade and/or mutually beneficial investment. However, realizing these opportunities often requires greater integration of power systems, including physical infrastructure and markets.

Interconnected power systems can provide more economic, reliable, and environmentally friendly outcomes for all the power systems within a region. The known benefits of regional integration in the electricity sector (WBG 2019d) include the following:

- Overall generation and transmission costs can be substantially reduced through coordination of expansion plans, optimal utilization of a more diverse set of resources, and the sharing of reserves. This can allow the postponement of expensive investments to meet national-level peak demand, while improving the reserve margins across the entire system, with a corresponding reduction in costs.
- Security of supply and climate resilience can be enhanced through mutual assistance among utilities, particularly in times of crisis. For example, in an emergency such as an unplanned outage, or whenever a country with insufficient generation capacity can only meet its internal load through electricity imports.
- Regional integration can enable the greater utilization of low-carbon resources available in a region, in particular solar and wind technologies, while helping build a more resilient system through greater diversification of supply to mitigate risks associated with each environmental impact.
- Power trade allows countries to gain the advantages of economies of scale by developing larger projects that may not be justified by national demand projections alone and that can provide better returns if a significant portion of the generated electricity is exported.
- When there is a significant difference in the electricity production costs between countries, both exporting and importing countries can mutually benefit from trade.

Removing transmission infrastructure bottlenecks is essential to realizing the mentioned benefits. If there is limited or no cross-border transmission capacity, then the required infrastructure must be constructed. Similarly, sustained development and closer integration of a region's power markets greatly enhance opportunities to achieve these desired outcomes.

3.1. DEVELOPMENT OF REGIONAL POWER MARKETS

The development of regional electric power markets traditionally follows an incremental process of evolving trade regimes. This ensures that the underlying economics and pricing remain fair as the institutions and mechanisms necessary for a fully competitive wholesale electricity market are built. Figure 6 summarizes the typical phases of regional power market integration. Following these phases, electricity trade tends to evolve from bilateral trading between neighboring countries to the formation of a regional energy and ancillary services market. Bilateral trading between neighboring countries can then evolve into bilateral or multilateral trading that runs through a third country. This can then increase in complexity through the buying and selling of power across synchronized power systems from one country market to others. Finally, a regional energy and ancillary services market becomes formalized as an electric power pool.

3.2. BENEFITS OF ELECTRIC POWER TRADE

Electricity trade in a well-developed regional market can improve reliability of supply, reduce energy prices, protect against power shocks, relieve shortages, provide incentives for market

Figure 6. Typical Phases of Regional Power Market Integration

	Bilateral Interconnection	Shallow Integration	Deep Integration
Planning and Investment Coordination	National planning and investment	Some coordination of national investments with optimized regional investment plan	Regional integration body empowered to require investments in agreed upon regional plan to be implemented
Regional Connectivity Architecture	Typically starts with 2 countries, later a wider interconnected grid	Interconnected grid involving a number of neighboring countries	Operation of a fully synchronous, multi-country, interconnected power system
Cross-Border Trading Arrangements	Long-term bilateral power purchase agreements (PPAs)	Long-term PPAs supplemented with short-term markets and cross-border transmission tariffs	Electricity pricing competition achieved through a range of market mechanisms (spot, day-ahead, ancillary services, transmission capacity auctions, etc.)
Technical and/or Regulatory Harmonization	Simple rules agreed upon for the operation of the interconnected system	Harmonization of rules, grid codes, and transmission tariffs	Harmonization of rules, grid codes, and transmission tariffs

Source: The World Bank's Power Systems Global Solutions Group.

extension and integration and, in some cases, facilitate decarbonization. The following subsections further explain some of the benefits of electric power trade.

RELIABILITY OF SUPPLY

Trading electricity can improve the reliability of supply through the "pooling" of generation capacity and national reserve capabilities among countries. The national power systems can engage in trade with partnering countries and draw on their capacity when required, in a situation such as an acute electricity shortage in one country, or when a power plant is unavailable due to upgrading or maintenance. There are three types of capacity exchanges:

- **Emergency supply of electricity.** These are based on real-time transactions and for a limited time (typically a few hours). A country experiencing an immediate power shortage can request electricity from the regional grid.
- **Scheduled outages that are covered by the regional grid.** These transactions involve the forward trading of electricity to cover planned shortages because of short-term capacity bottlenecks.
- **Spinning reserve capacity supplies.** These are for immediately supplying the reserve capacity needed to cover short intervals, such as when national generation capacity is sufficient, but spinning reserve capacity may be too low (El-Katiri 2011).

Payment for these types of exchanges usually involves cash settlements, typically overseen by a financial regulator, or payment can be in-kind over a specified settlement period. Electricity exchanges require legal and institutional frameworks, such as a multilateral legal framework for regional electricity trade and a harmonized set of commercial rules for trade (El-Katiri 2011).

To evaluate a power system's reliability in generation expansion planning, power system managers, designers, planners, and operators have utilized a wide range of criteria in their respective areas of activity. The costs of failure to reach reliable power supply may be expressed by several components falling into two main categories. The first is the cost of unserved energy (USE), typically assessed through the value of lost load (VoLL), defined as the value in dollars per megawatt-hour (MWh) placed on a unit of electricity not supplied due to an unplanned interruption. The second is the cost of unmet reserve (USR), defined as the cost due to the system's inability to meet operational reserve requirements, in terms of margin reserves (in $/MW) and spinning reserves ($/MWh) which may lead to an unplanned interruption. USE and USR are used to estimate the economic value of the cost of electricity interruptions to electricity customers and the economy as a whole.

ECONOMIC BENEFITS FROM COMMERCIAL TRADE

Electricity trade, undertaken for commercial purposes, aims to exploit the differences in system efficiencies and cost advantages between different producers (countries or individual utility companies), achieved by purchasing lower cost electricity from available sources (El-Katiri 2011). Economic benefits of electricity trade arise from operational and capital cost savings. The operational cost savings mainly stem from regional differences in fuel prices, differences in chronological patterns of load, geographical diversity of renewable profiles, and the ability to efficiently meet operational reserve requirements. The capital cost savings stem from differences in the chronological pattern of load and renewable profiles that allow the pooling of generation resources at a regional level, requiring less generation capacity and lower planning reserve requirements (WBG 2017b).

There are two main approaches to commercial electricity trade:

- **Economy energy exchanges.** These are short-term electricity exchanges that take advantage of differences in the short-run marginal costs incurred by two countries' utilities. Electricity is purchased from where it is produced most cost-effectively, creating an increase in revenue for the exporting national utility and a net savings for the importing utility. Table 3 illustrates the resulting mutual benefits. In the example, the transaction to trade quantity Q of electricity takes place at price P. From the exporter's perspective, the benefit is the extra revenue minus Ce, the exporter's production cost of electricity. The importer receives the benefit of the difference between the importer's own production cost Ci and price P. The total benefit to be shared between the two parties is (Ci - Ce) x Q.
- **Firm energy supply.** This trading approach provides a medium- or long-term solution for a country's generation capacity needs, based on a contract between two utilities. A national utility commits to supply specific amounts of electricity on a "take or pay" basis. This helps the importing country meet base or peak load supply in cases where they are unable or not incentivized to construct their own power plants (El-Katiri 2011).

Variation in chronological patterns of demand across countries can create significant incentives for commercial trade, resulting in economic savings and greater security of supply. As different countries' seasonal, monthly, and daily fluctuations in electricity demand may display significantly different patterns, countries can benefit from smoothing out their individual peaks by importing other countries' off-peak electricity. As a general rule, seasonal correlations of electricity demand are influenced by the latitude and climate of jurisdictions (with countries further north requiring less energy for cooling, etc., in summer), while intraday peaks are largely synchronous in the north-south direction but, on a universal time scale, they have a characteristic time lag moving from east to west (Antweiler 2016). The time zone difference between Morocco and Saudi Arabia, for example, could provide a sound basis for

Table 3. Illustration of Short-Term Economic Benefits from Electricity Trade

Exporter	Importer
Revenue (= P * Q)	Cost with no trade (= C_i * Q)
Cost (= C_e * Q)	Cost of import (= P * Q)
Benefit = revenue - cost	Benefit (savings) = (C_i - P) x Q
E.g.:	
Exporter	**Importer**
P = 111 $/MWh	C_i = 136 $/MWh
C_e = 86 $/MWh	P = 111 $/MWh
Benefit = 25 $/MWh	Benefit (savings) = 25 $/MWh
Total benefit = (136 - 86) $/MWh * Q = 50 $/MWh * Q	

Source: Original compilation.
Note: C_e = exporter's production cost of electricity; C_i = importer's production cost of electricity; MWh = megawatt - hour; P = price of electricity; Q = quantity of electricity.

intraday “reciprocal load smoothing,” should power trade between these countries become possible.

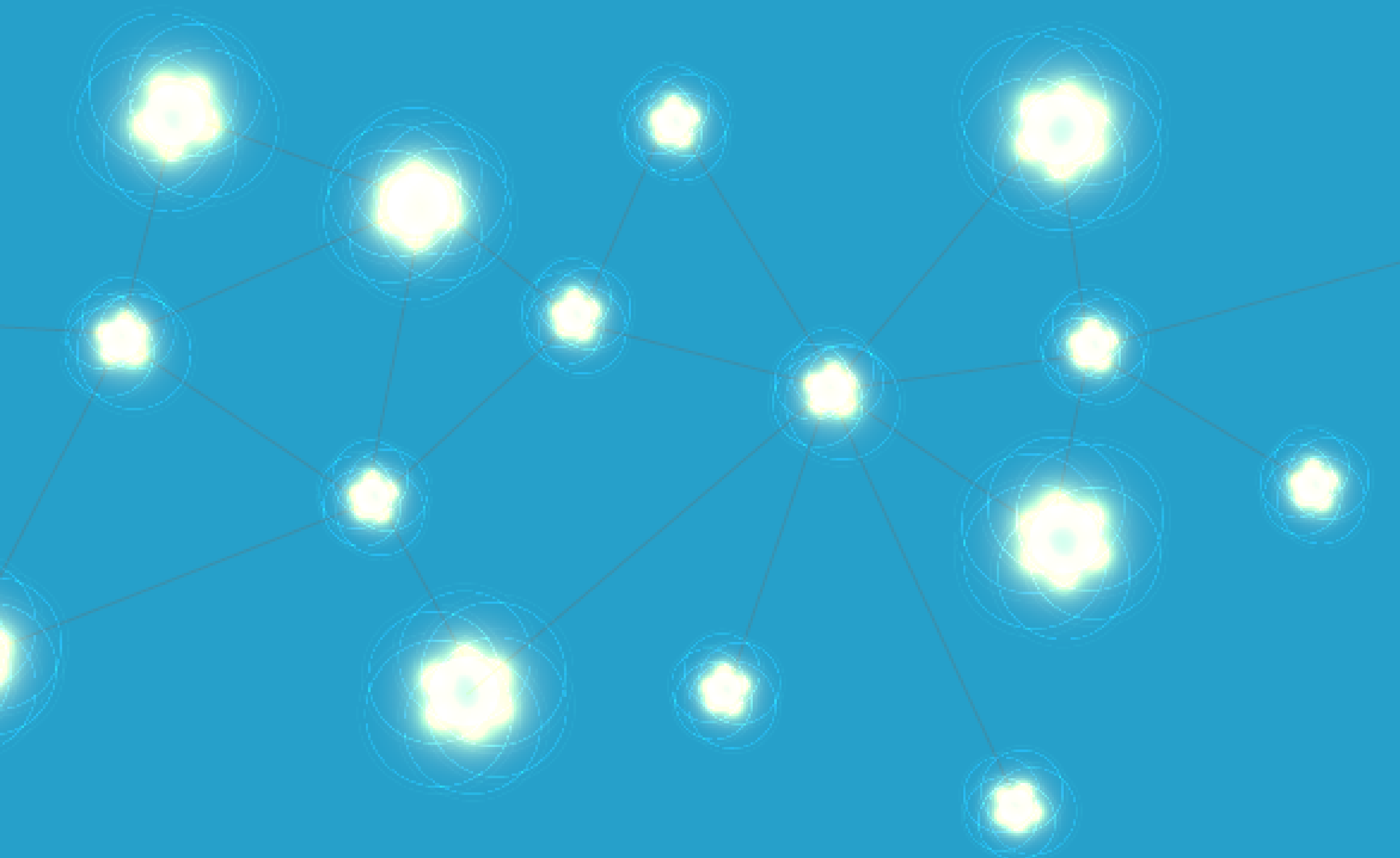
OTHER BENEFITS

The benefits of electricity trade extend beyond the enhanced reliability of supply and economic savings. Trade between countries supports economic and political stability as ties become stronger. It helps to secure the supply of gas to meet the growing electricity demand in a region, as well as to enable economic diversification by facilitating the growth of gas-based industries (WBG 2016b).

Trade is also beneficial to meet renewable energy targets set in different countries in a region. This is because the aggregated regional renewable resource profile is typically smoother than the profiles of individual countries. Also, flexible resources in different countries can be pooled to complement renewable output and to provide ancillary services, such as spinning reserves, resulting in a less costly variable renewable energy integration (NREL 2013).

At a broader level, these benefits could help the countries in the Pan-Arab region progress toward some of their national and regional goals. On a national level, some of these priorities are: achieving renewable targets at a lower cost, increasing energy efficiency, achieving Intended Nationally Determined Contributions, executing subsidy reforms, securely supplying a growing high-peak electricity demand, and facilitating the execution of new large investments with limited financing sources. On a regional level, priorities connected to electricity trade include: accomplishing the goals of the renewable energy regional strategy; fostering regional institutional cooperation; and establishing a market and an enabling environment for electricity trade (WBG 2018d).

4 REGIONAL INTEGRATION OF ELECTRICITY MARKETS IN THE PAN-ARAB REGION



Historically, the Pan-Arab region has had a relatively high interconnection transfer capacity, which reached 7.7 gigawatts (GW) by 2018. However, electricity exchanges as well as interconnection utilization have been very low. In 2014 only 2 percent of the electricity generated in the region was exchanged among neighboring countries, less than 10 percent of the regional interconnection capacity was being used, and load factors barely reached 2 percent (WBG 2016b). The only interconnections utilized at a reasonable level are Morocco⇆Spain, Egypt⇆Gaza, and Jordan⇆West Bank (WBG 2017b).

Regional cooperation and governance are essential components in building regional electricity markets. A top-down vision and a robust regulatory framework are needed to facilitate electricity trade. The Gulf Cooperation Council (GCC), Mashreq, and Maghreb subregions have taken steps toward transmission integration and coordination. However, the institutions required to facilitate power trade and the harmonization of regulations are still underdeveloped and present challenges that must be addressed before there is region-wide electricity trade. The following subsections give a brief background of the subregional initiatives developed within the Pan-Arab region.

4.1. THE GCC REGION

The GCC Interconnection Authority (GCCIA) was established in 2001 and consists of six member states: Kuwait, Saudi Arabia, Bahrain, Qatar, the United Arab Emirates (UAE), and Oman. Later, in 2009, the members signed two agreements: the General Agreement and the Power Exchange and Trade Agreement (PETA). The General Agreement establishes the principles of electricity cooperation, such as the rights of interconnection, connection fees, interconnection performance defaults, termination of membership, and, more broadly, the interconnection's governing law. The PETA is a commercial agreement among power providers within the GCC subregion. It established the legal terms for commercial trade, such as the technical and financial details of the project. It also outlines cost and contribution structures, emergency support mechanisms, and key responsibilities. The PETA consists of three separate subagreements: (i) the Trading Agreement, including common legal terms and conditions; (ii) the Interconnection and Use of System Agreement; and (iii) the Interconnector Transmission Code (El-Katiri 2011).

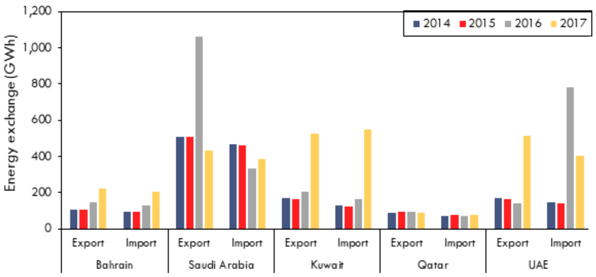
The GCCIA cross-border interconnections were established in three phases. In the first phase, completed in 2009, the GCCIA formed the GCC north grid by connecting the power grids of the northern states of Kuwait, Saudi Arabia, Bahrain, and Qatar. This included the construction of a 400 kilovolt (kV) grid in Kuwait, Saudi Arabia, and Qatar, with a 400 kV submarine cable link to Bahrain, as well as a back-to-back high voltage direct current (HVDC) transmission line to connect the 60 hertz (Hz) Saudi Arabian system to the 50 Hz systems of the other GCC countries. In the second phase, the interconnection authority completed a 220 kV line between the United Arab Emirates and Oman, forming the GCC southern grid. This project also formed the Emirates National Grid by integrating the isolated networks of the various emirates and created an integrated northern grid in Oman. The third phase interconnected the north and south grids. It included a double-circuit 400 kV line from Salwa to Shuwaihat (UAE) and a double- and single-circuit 220 kV, 50 Hz line from Al Ouhah (UAE) to Al Waseet (Oman) (WBG 2013).

The GCC interconnection primarily uses two vehicles for trade:

- **Scheduled exchanges.** These are prearranged bilateral trades between GCC Member States that are freely negotiated between the members. Once the agreement is reached, the members must procure transmission capacity rights for use of the GCC interconnection from the GCCIA. Once confirmation is received, the trade is completed.
- **Unscheduled exchanges.** These are used on a contingency basis. They improve the reliability of supply by allowing countries to access supply in the case of an emergency (WBG 2013).

GCC regional power interconnection has advanced the most in promoting electricity exchanges within the Pan-Arab region. Figure 7 details the energy exchanges completed, in gigawatt-hours (GWh), among the GCC members between 2014 and 2017. Electricity exchanges have increased over time, with the balance of electricity traded increasing from 734.3 GWh in 2016 to 878.4 GWh in 2017 (an increase of 20 percent). Saudi Arabia and, more recently, Kuwait and the United Arab Emirates registered the highest quantities of exports and imports. Although the volume of electricity traded has increased over time, a significant portion of it involves unscheduled exchanges to prevent emergencies. Member countries favor trading on an in-kind basis, over market-based trading (in-cash), to settle unscheduled exchanges (GCCIA 2017).

Figure 7. Electricity Exchanges by GCC Members, 2014–17, in GWh



Source: GCCIA 2017.
Note: GWh = gigawatt - hour; UAE = United Arab Emirates

By 2016, the GCC interconnection had successfully been used in 1,692 incidents to stabilize and support Member States' power systems. These transfers ranged from 100 megawatts (MW) to 3,000 MW in size and they provided greater stability to the grid and succeeded in avoiding partial or total blackouts during some critical incidents in the GCC. Moreover, these transfers had led to more than US$2.2 billion in savings between 2011 and 2016 from reducing installed capacity, operation and maintenance (O&M) costs, and operational reserves, as well as through avoiding programmed outages due to emergency support (GCCIA 2017).

Despite the achievements noted above, the GCC subregion is still facing a number of barriers to expanding the volume of electricity traded by its Member States. Thus, while the GCC countries have achieved grid interconnection levels that surpass those of other Arab states, the utilization of the available transmission capacity remains quite low. Part of the reason is that the trades are still primarily conducted "in-kind." Essentially, this is electricity delivered in an emergency, for electricity to be returned later. This type of transaction has a small share of volume in any power system, as compared with the regular market-based transactions in which the commodity (electricity) is exchanged for cash.

In turn, the lack of a transparent basis for pricing electricity across countries with subsidized fuel for electricity generation is the main reason why the parties tend to stick to in-kind transactions. With the degree of fuel subsidy varying from country to country, it is difficult for them to agree on a fair price for the electricity being exchanged.

Leakage of a country's domestic fuel subsidy to a neighboring state—sometimes referred to as "exporting a subsidy"—is a distinct deterrent to electricity trade in the region. The energy-exporting countries have traditionally kept their retail electricity tariffs low as part of a political bargain whereby control is centralized in return for hydrocarbon wealth redistribution under generous social protection schemes. Artificially low tariffs are in turn supported by subsidized fuel inputs to generators from state-owned oil and gas companies, which bear the domestic cost in return for the right to sell fossil fuel abroad at a significant profit. As such, energy traded at the wholesale price extends those subsidies to foreigners, and state-owned oil and gas companies object to this implicit wealth transfer incurred when utilities sell power abroad (El-Katiri 2011; WBG 2013, 2019c).

Apart from ad hoc emergency exchanges, bilateral contracts are the only form of cross-border trading that is relatively regular among GCC countries. However, each bilateral electricity trade may require a lengthy process of government approval. Unless the approval procedure is streamlined (which requires a pre-agreed pricing methodology), the practice of bilateral contracts will fall short of enabling rapid response to supply and demand signals; day-ahead trading, for example, will not be possible (WBG 2019c).

4.2. MASHREQ REGION

The Mashreq countries/economies in this study are: Egypt, Iraq, Jordan, Lebanon, Libya, West Bank and Gaza, Sudan, and Syria. In 1988, in the Mashreq region, Egypt, Iraq, Jordan, Syria, and Turkey initiated an effort to upgrade their electricity systems to a regional standard. Later, they were joined by Lebanon, Libya, and West Bank and Gaza, to form the EIJLLPST (Egypt, Iraq, Jordan, Libya, Lebanon, West Bank and Gaza, Syria, and Turkey) regional interconnection (WBG 2013). Transmission lines of 400 kV and 500 kV make up the EIJLLPST interconnection, linking the national power systems of its members. The regional grid further connects: Egypt to Libya through a 220 kV line; Syria to Turkey through a 400 kV line; Iraq to Turkey through a 400 kV line currently operating at 154 kV; and Iraq to Iran through a 400kV line (WBG 2010).

The original five countries in the regional interconnection—Egypt, Iraq, Jordan, Syria, and Turkey—signed a general trading agreement in 1992. This established their commitment to develop interconnections, as well as shared objectives of providing mutual assistance and sharing benefits as part of the network, to improve the reliability of supply, and to improve the region's economies through the exchange of surplus power.

In 1996, the general trading agreement was amended to become a comprehensive agreement that outlines the terms and conditions for use of the interconnection. The terms and conditions cover: (i) reserve sharing during emergencies; (ii) capacity transactions; (iii) interchange of surplus power and energy; (iv) regulation of energy flows to maintain schedules; (v) regulation of reactive power flows; (vi) transmission services—making each country's transmission facilities available for the purpose of transmitting power and energy to other parties; (vii) operating reserves, including maintaining minimum levels of reserves and their sharing between countries; (viii) the coordination of maintenance schedules; and (ix) coordination of planning to increase reliability and maximize the value of the interconnection.

The interconnection agreement also established the scope and duties for the permanent committees, which are not fully functional (WBG 2013). These permanent committees are the:

- **Steering committee.** This committee is responsible for promoting reliable and efficient operation of the interconnection and the interconnected power systems by coordinating design, planning, and operating activities.
- **Planning committee.** This committee aims to foster greater coordination among the members as well as determine if the plans conform to Steering Committee rules and guidelines. It plays an analytical and planning role.
- **Operating committee.** Each pair of neighboring countries is required to maintain a bilateral operating committee. The operating committees are required to take all actions necessary to ensure delivery and payment for power in accordance with the interconnection agreement and any agreement between the countries.

Despite the interconnection agreement, there has been limited trade of electricity over the network. Tight generation supply in some countries, lack of a harmonized regulatory framework, limited access to national transmission networks, and the fact that trade is, generally, restricted to a single government-owned entity in each country constrain electricity exchanges within the region. In addition to these issues, the interconnected systems are often not synchronized, therefore, part of a national grid system must be isolated from the main grid to accept imports from another country (WBG 2013).

Overall, the national transmission systems in the Mashreq subregion are constrained by the lack of a regional coordination center and the lack of a formal regional market. These institutions would facilitate market transactions, promote regional trade, and compensate entities for providing transport services, or determine the technical feasibility of transactions. A regional coordination center would bring significant savings through more optimal generation capacity planning, reduced settlement costs (due to having only one central settlement system rather than five or more separate national ones), and reducing the cost of load interruptions (WBG 2010).

4.3. MAGHREB REGION

The Maghreb regional interconnection was established in the 1950s by the North African countries of Morocco, Algeria, and Tunisia. It has since evolved into multiple high-voltage transmission interconnections between the three countries. In 1997, these countries connected to the European Network of Transmission System Operators for Electricity (ENTSO-E) via the 2x400 kV alternating current (AC) interconnection between Spain and Morocco. Also, Morocco, Algeria, and Tunisia are all synchronized with the pan-European high-voltage transmission network (WBG 2013).

In 2003, the European Commission and the energy ministers of the Maghreb nations signed a protocol with the objective of developing a regional energy market that would eventually be integrated into the EU electricity market. The protocol called for the creation of mechanisms to facilitate trade, such as establishing how to deal with tariffs, trans-border networks and constraints, and compensation for network damage.

Later, in 2010, the Maghreb nations signed the Algiers Declaration. In this declaration, these countries agreed to take steps toward harmonizing laws and regulatory frameworks and economic and technical conditions for the creation of a viable market for electricity. They also agreed that this market would be based on network access provided on a nondiscriminatory and transparent basis and properly priced to promote trade (WBG 2013).

4.4. RATIONALE FOR INTERCONNECTING THE THREE SUBRGIONS

Based on the fundamentals of regional market integration discussed earlier, power system interconnection has a number of basic benefits for all participating countries. Expanding the geographic scope of interconnection means scaling up the same fundamental benefits—starting from deferring expensive investments to meeting national-level peak demand and including opportunities for commercial trade based on short-term marginal cost differences. A greater geographic scope means greater diversification of resources available in each subregion and greater ability to scale up deployment of renewable energy sources. For the GCC, Mashreq, and Maghreb subregions, specific benefits from interconnection include the following:

- **Connecting the GCC with the Mashreq** would solve one of the remaining problems in intra-GCC trade: the region's relatively uniform load pattern, that is, the typical summer peak and daytime peak demand in the afternoon hours (El-Katiri 2011). Notably, the Saudi Arabia ⇆ Egypt interconnection planned for 2022 would benefit both countries by sharing their reserve capacity and in exchanging power on the basis of differences in daily and seasonal demand profiles.
- **Similarly, planned Saudi interconnections with Jordan (by 2023) and Iraq (by 2025)** would focus on using Saudi Arabia's surplus capacity in off-peak hours and off-peak seasons. Furthermore, the connection with the Mashreq system would allow the GCC to subsequently develop the interconnection with Turkey to gain access to the EU market. The emphasis would be on linking the Saudi grid directly or through Iraq to the Turkish grid by HVDC lines—to enable power exchange with Turkey and, potentially, to export renewable energy to European markets.
- **Connecting GCC (and the Mashreq) with the Maghreb**, while still a long-term prospect, is promising from two perspectives. First, it could smooth the daily peaks in both the GCC and the Mashreq, given the significant time zone difference between the two subregions. Second, the solar power development projects in the Maghreb (such as the Desertec project in Morocco) can turn these countries into strong clean energy trading partners for the GCC (El-Katiri 2011).

4.5. KEY CHALLENGES TO ELECTRICITY TRADE IN THE PAN-ARAB REGION

The GCC, Mashreq, and Maghreb have each taken steps toward regional cooperation in their transmission networks but are still facing market integration challenges. These vary by subregion, though several challenges affect the prospects of Pan-Arab market integration as a whole:

- **Countries need to develop and agree on a pricing approach suitable for cross-border trade on a commercial basis.** In many cases this might include domestic pricing reforms of subsidized fuels, including natural gas. Artificially low fuel prices have effects throughout the supply chain of the electricity sector, hindering power trading among and within the subregions. Most trading transactions are still conducted "in-kind" in the GCC, currently the most advanced subregional market. In addition to discouraging trade, fuel subsidies promote inefficient consumption decisions, resulting in increased infrastructure needs and potentially increased supply disruptions. Applying international fuel prices specifically to cross-border transactions without eliminating subsidies at home is a possible interim solution in the early phases of the regional market (WBG 2019b). However, countries are encouraged to accelerate the phasing out of these subsidies to fully exploit the potential of trade.
- **Regional institutions for power trade need to be founded and empowered** within a common framework that ensures efficient coordination. The development of institutions can build on existing bodies such as the CGGIA trading framework, the Mashreq committees, and the Algiers Declaration. The GCCIA has implemented a pilot project that will provide valuable experience for developing these institutions. In addition to requiring the authority to promote trade, these institutions also require adequate resources to achieve this objective, such as analysis tools and data.
- **Harmonized regulations of cross-border trade need to be developed.** This requires developing a regional grid code and a regional commercial code that cover the technical and commercial aspects of regional trade. Developing regulations for cross-border trading would involve establishing a working group that defines the rules for planning and operating networks on a regional level, such as through congestion management guidelines. A commercial code is required to establish a mechanism and rules for trades where bids and offers are cleared and settled periodically. The Pan-Arab Electricity Market (PAEM) would establish needed market rules and grid codes (or technical requirements), with the understanding that Member States will advance needed reforms at their own pace. Harmonized regulations will play a key role in implementing the PAEM.
- **It is also necessary to mobilize finance for investment in generation and transmission assets to meet demand.** Introducing regional electricity trade will reduce the need for new generation capacity. However, it will require investments to enhance or expand certain transmission lines. A more detailed transmission investment plan is an important next step. This is best prioritized within a coordinated regional planning framework that optimizes the development and operations of the PAEM, and allows participating countries to meet demand in cost-effective and efficient ways.

5 THE WORLD BANK'S ELECTRICITY PLANNING MODEL

This study uses a power system planning model developed in-house by the World Bank: the Electricity Planning Model (EPM). The EPM is an optimization model that determines a sequence of investment decisions to build new power generation capacities while optimizing the least-cost option to meet resource, technological, environmental, policy, and any other specified constraints. An essential component of the model is the merit order or economic dispatching of existing and new generation capacity. The methodology fully exploits the synergies between demand and renewable energy profiles. The following subsections outline the model's main capabilities, its key assumptions, and the optimization objectives and constraints, after which the scenarios analyzed in this study are described.

5.1. KEY FEATURES OF THE ELECTRICITY PLANNING MODEL

The EPM is a long-term least-cost planning model that minimizes system costs over multiple years, including both fixed (annualized capital and fixed operation and maintenance [O&M]) costs and variable (fuel and variable O&M) costs, subject to meeting a number of physical constraints that include generation and transmission capacity among zones, and spinning reserve and capacity reserve requirements. The model determines:

- Hourly electricity costs with trade for different countries and zones, which are essential to value the energy traded
- Wholesale power supply costs
- Where and how many renewable resources should be deployed to maximize their value to the system—a critical issue in current Pan-Arab planning efforts
- The optimal capacity additions over time to complement renewable generation accounting for existing generating units, energy storage, demand-side response, and/or carbon constraints
- The optimal retirement schedule of the existing units over time
- The utilization of the transmission lines interconnecting states (important to design trade contracts)
- The impact of different market conditions (for example, fuel prices, fuel subsidies, carbon limits, etc.) and technology cost assumptions on the optimal capacity expansion plan and the optimal energy mix
- The cost of implementing specific environmental policies, such as renewable portfolio standards, caps on carbon emissions, taxes on carbon emissions, and carbon emissions rates.

The model is based on the following assumptions:

- The market participants are not strategic, and they behave in a perfectly competitive manner, that is, the power plant owners submit their true costs as bids
- The demand projection is exogenous to the model. The projected demand is considered perfectly inelastic, which implies that the maximization of the social welfare can be replaced by minimization of the system cost
- The electricity trade among regions is economically efficient (optimal), which translates to a single objective of minimizing costs for all countries
- The pricing is assumed to be efficient and does not provide incentives to market participants to deviate from the optimal behavior.

The objective of the modeling exercise is to minimize at once the sum of fixed and variable generation costs (discounted for time) for all zones and all years considered. This minimization is subject to the following parameters: demand equals the sum of generation and unserved energy; available capacity is existing capacity plus new capacity minus retired capacity; generation does not exceed the maximum and minimum output limits of the units; generation is constrained by ramping limits; reserves are committed every hour to compensate for forecasting errors; renewable generation is constrained by wind and solar hourly availability; excess energy can be stored in storage units to be released later or traded between the other zones; and the power flows are constrained by transmission network topology and transmission line thermal limits.[11]

As the overall objective of this study is to assess the benefits of electricity trade among countries, it is important to highlight the following observations regarding the model:

- EPM does not account for the load flows within a domestic transmission system
- The model does account for wheeling based on the marginal cost of electricity, intrinsically, subject to line capacity constraints
- Renewables generation technologies lack provision for excess reserve storage.

5.2. DESCRIPTION OF THE CASES ANALYZED

Table 4 presents the seven cases considered for analysis in this study. Six main cases (C0-C5) are used to determine the benefits of electricity trade under various pricing and environmental policy assumptions, while holding the electricity demand on the same trajectory for each case. Case 6 (C6) assumes a lower demand trajectory due to energy efficiency measures.

To assess the potential benefits of increased trade among the power systems in the Pan-Arab region, the analysis starts with a baseline scenario (C0) that assumes no electricity trade takes place and that countries use natural gas priced at current (local) levels for electricity generation. In this base case, each country independently makes its own capacity investments to satisfy its projected demand. The base case can then be compared with Case 1 (C1), a case that assumes existing and planned cross-border interconnections are fully operational, at transfer capacity levels, and available for electricity trade in a regional power pool scheme.

Table 4. Cases Considered for the Study

Base Case (Case 0, CO)	Natural gas - current market prices, no electricity trading
Case 1 (C1)	Natural gas - current market prices, electricity trading
Case 2 (C2)	Natural gas - international prices, no electricity trading
Case 3 (C3)	Natural gas - international prices, electricity trading
Case 4 (C4)	Natural gas - international prices, no electricity trading, CO_2 emissions limit
Case 5 (C5)	Natural gas - international prices, electricity trading, CO_2 emissions limit
Case 6 (C6)	Natural gas - international prices, electricity trading, demand-side measures

Note: CO_2 = carbon dioxide.

To assess the impact that higher natural gas prices have on investment and regional electricity trade, this study analyzes a set of cases where Pan-Arab countries use European market prices (international prices) for natural gas (European Union Hub prices).

Case 2 (C2), similar to the base case, assumes that cross-border interconnections are not available for electricity trade, while Case 3 (C3) assumes a fully integrated transmission network with trade.

The study analyzes two more cases, Case 4 (C4) and Case 5 (C5), to evaluate the impact of carbon policy on generation investments and trade. To build these two cases, the study applies a policy that limits CO_2 emissions from the power sector, starting in 2020 until 2035, to the previously described cases, Case 2 and Case 3. To set these limits, consideration was first given to the Intended Nationally Determined Contributions (INDCs) that Pan-Arab countries published after COP21.[12] However, it is difficult to standardize an average reduction target for the region. While some economies have not published their INDCs (namely, Libya, Syria, and West Bank and Gaza), others lacked clarity on their CO_2 reduction goals (Bahrain, Egypt, Iraq, Kuwait, Sudan, and the United Arab Emirates). The countries that have set INDCs

[11] Section 6 and appendix B give details of input assumptions of the EPM. For a generic technical description of the inputs, outputs, and mathematical formulations used in the model, refer to appendix F.

[12] 2015 Conference of the Parties to the United Nations Climate Change Convention.

have provided CO_2 reduction targets under two categories: unconditional (ranging between 1 percent to 13 percent reduction from a business-as-usual scenario) or conditional on international support (ranging from 12.5 percent to 41 percent emissions reduction compared with a business-as-usual scenario) by the year 2030.[13] Given the lack of uniformity of CO_2 reduction targets by country, this study assumes a regional limit for CO_2 emissions that begins as a 1 percent reduction in 2020 (from the baseline scenario) and reaches 18 percent by 2035.

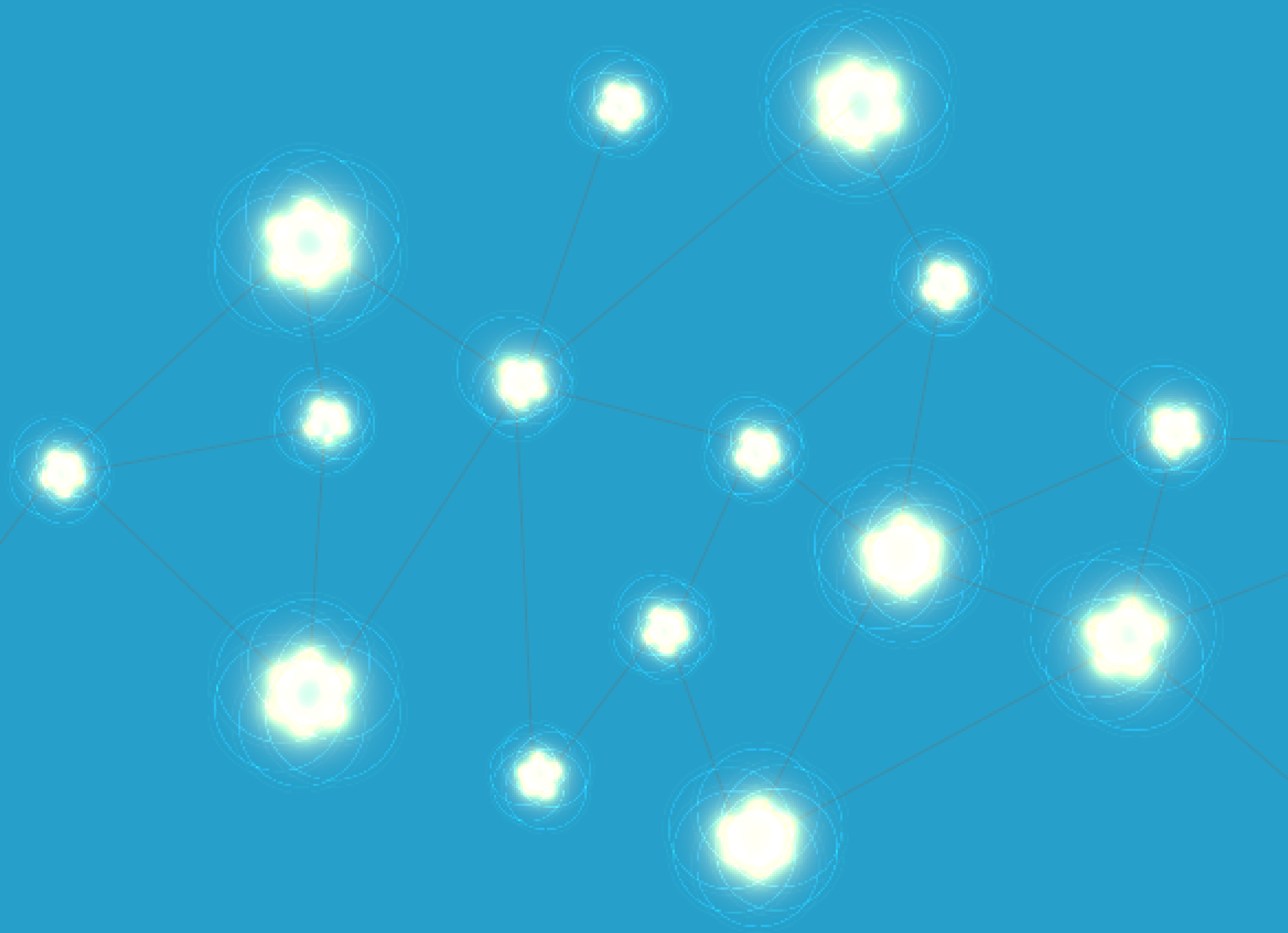
Finally, the study considers Case 6 to model the impact of a possible contraction in electricity demand relative to the other cases. Under Case 6, all the countries adopt demand-side measures, such as energy efficiency programs, in order to progressively reduce future electricity consumption. It is further assumed that the adoption of these measures will cause the systems to experience a demand reduction of 0.5 percent of the base demand (the demand projection used in all other cases of this study) in 2020, a reduction of 10 percent in 2025, and 20 percent in 2030 through 2035.

Chapter 8 presents an economic planning framework for cross-border interconnections. This framework is used to identify the benefits among a specific group of interconnectors, to assess potential transmission investment opportunities, and to categorize interconnectors according to their average annual utilization rates.

To prioritize interconnectors, the study considers both their potential utilization and their economic benefits. It is important to note that due to the complexity of the model, even if a single interconnector proves to be highly utilized and to have the most economic benefits by itself, the figures might change when interacting with other interconnectors from neighboring countries. Therefore, other criteria, such as countries' willingness to cooperate and technical characteristics of the potential interconnector, should also be used to assess the feasibility of the transmission lines.

[13] Appendix D contains a summary of the INDCs submitted by the Pan-Arab countries.

6 MODELING INPUTS AND ASSUMPTIONS



This chapter details the input data and assumptions on a regional and national basis. These main data include existing, under construction, and planned generation; peak and energy demand projections and demand profiles; existing, under construction, and planned interconnections; natural gas price projections, natural gas consumption limits, and liquid fuel prices; and capacity factors for renewable energy technologies.

Overall, this study considers 11 generation technologies: open cycle gas turbine, combined cycle gas turbine, steam turbine, diesel generator, hydroelectric, nuclear generation, coal-fired steam turbine, wind farm, solar photovoltaic (PV), concentrating solar power (CSP), and integrated solar combined cycle (ISCC).

6.1. EXISTING CAPACITY ASSUMPTIONS

Table 5 presents the assumptions regarding existing installed capacity by technology and country. The total existing capacity for the region, in 2018, is 299 gigawatts (GW). This includes 107.3 GW (36 percent) of combined cycle, 92.5 GW (31 percent) of open cycle gas turbines, and 75.9 GW (25 percent) of steam turbine capacity. It also includes 2.3 GW of wind (<1 percent), 1.3 GW of solar PV, and 525 MW of CSP. However, the first three mentioned fossil-fueled technologies dominate the capacity mix in the region, with over 92 percent participation.

In terms of capacity by country, Saudi Arabia registers the highest amount of capacity with about 85 GW, followed by Egypt with 39 GW, the United Arab Emirates with 32 GW, and Iraq with 30 GW. At the low end of the list are West Bank and Gaza with 1.2 GW, Yemen with 1.5 GW, and Lebanon with 3 GW.

6.2. PLANNED AND UNDER CONSTRUCTION CAPACITY

Table 6 displays the generation capacity additions, by technology and country, that are either planned or are under construction over the period of 2018–30. Under these plans and ceteris paribus (with other conditions remaining the same), a total of 270 GW would be added to the regional generation capacity, of which 187 GW or almost 70 percent of the total would be

Table 5. Existing Installed Capacity by Technology and Country, in MW (2018)

Country	CC	GT	ST	DG	Hydro	Coal	Wind	PV	CSP	Total
Algeria	6,907	10,368	2,435	-	276	-	10	432	150	20,578
Bahrain	3,096	700	125	-	-	-	1	10	-	3,932
Egypt	12,647	7,845	14,799	-	2,832	-	747	50	20	38,940
Iraq	4,952	15,079	5,995	1,769	2,524	-	-	-	-	30,319
Jordan	2,837	188	242	810	-	-	287	460	-	4,824
Kuwait	6,496	2,925	9,354	-	-	-	10	10	50	18,845
Lebanon	930	140	1,694	-	253	-	-	-	-	3,017
Libya	3,995	4,638	1,190	-	-	-	28	-	-	9,851
Morocco	834	1,230	600	292	1,770	2,895	1,1018	-	180	8,819
Oman	7,099	2,352	-	149	-	-	-	-	-	9,600
WB&G	1,140	-	-	15	-	-	-	-	-	1,155
Qatar	7,470	4,408	-	-	-	-	-	-	-	11,878
Saudi Arabia	21,436	31,841	31,226	270	-	-	-	-	-	84,773
Sudan	458	220	906	535	2,250	110	-	-	-	4,479
Syria	2,800	967	3,324	-	1,571	-	-	-	-	8,662
Tunisia	2,559	2,218	1,080	-	62	-	208	10	-	6,138
UAE	21,644	2,460	2,460	31	-	-	-	373	125	31,577
Yemen	-	407	495	590	-	-	-	-	-	1,492
Total	**107,300**	**92,470**	**75,925**	**4,461**	**11,539**	**3,005**	**2,309**	**1,345**	**525**	**298,878**

Source: PLATTS database; Electricity and Cogeneration Regulatory Authority (http://www.ecra.gov.sa/en-us); Arab Union of Electricity (http://www.auptde.org/PublicationsCat.aspx?lang=en&CID=284); Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority (EWA); Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment.
Note: CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; GT = gas turbine; Hydro = hydroelectricity; MW = megawatt; PV = photovoltaic; ST = steam turbine; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

added by just four countries: Saudi Arabia (far ahead of the others with 81 GW), Iraq, Egypt, and Algeria. Renewable energy capacity would be about 50 percent of the total additions, followed by the gas-fired combined cycle technology (25.5 percent), steam turbine technology (12.3 percent), and other technologies in substantially smaller shares. Renewable technologies would be represented by solar PV, CSP, and wind. PV is the most popular renewable technology due to the high solar radiance potential in the region and the decreasing installed capacity costs. In addition, Saudi Arabia is the only country investing in ISCC technology, aiming for two power plants totaling 2 GW capacity. Although not reflected in table 6, the model considers power plant retirement schedules.

Egypt, Saudi Arabia, and the United Arab Emirates plan to add nuclear technology to their mix (8.4 GW in total).

It must be kept in mind that, while the expansion plans available from countries are instructive, the optimization analysis in this study accommodates a broader set of possible expansion paths for each technology. The resulting additional capacity targets by country and technology are expected to deviate from those shown in table 6.

6.3. PEAK POWER AND ENERGY DEMAND PROJECTIONS

Energy demand and peak power projections data were compiled from various sources, including ministries of energy and electricity companies of different countries in the Pan-Arab region. Peak power and energy projections for the period 2018–30 were provided by: The Arab Forum for Environment and Development, Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment. Some of the historical electricity demand figures were retrieved from the Arab Union of Electricity. The data on losses comes from the International Energy Agency.

Table 6. Planned/Under Construction Capacity by Technology and Country, in MW (2018–30)

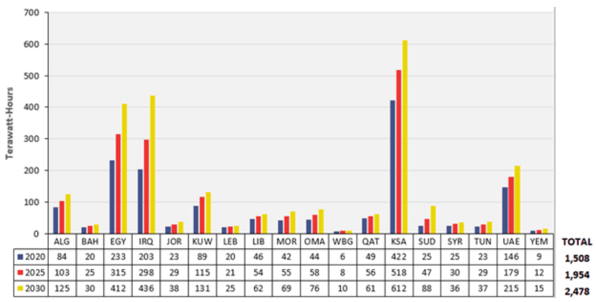
Country	CC	GT	ST	DG	Hydro	Nuclear	Coal	ISCC	RE Targets[14]	Total
Algeria	10,800	-	-	-	-	-	-	-	22,000	32,800
Bahrain	4,125	-	-	-	-	-	-	-	700	4,825
Egypt	2,430	7,940	10,550	-	32	2,400	1,950	-	10,700	36,002
Iraq	15,000	2,500	13,000	-	-	-	-	-	6,200	36,700
Jordan	3,000	-	900	-	-	-	-	-	2,830	6,730
Kuwait	9,350	-	-	-	-	-	-	-	2,000	11,350
Lebanon	570	-	-	-	126	-	-	-	1,000	1,696
Libya	250	2,910	2,800	-	-	-	-	-	2,200	8,160
Morocco	2,400	-	38	-	1,375	-	3,026	-	10,000	16,839
Oman	1,245	-	-	78	-	-	-	-	2,650	3,973
WB&G	650	-	-	-	-	-	-	-	-	650
Qatar	3,549	-	-	-	-	-	-	-	1,800	5,349
Saudi Arabia	12,913	30	4,490	-	-	3,200	-	1,995	58,700	81,328
Sudan	-	-	-	37	360	-	600	-	5,520	6,517
Syria	100	-	-	-	-	-	-	-	-	100
Tunisia	450	-	-	-	-	-	-	-	4,700	5,510
UAE	2,299	-	1,440	-	-	2,800	-	-	5,030	11,569
Yemen	-	-	-	-	-	-	-	-	-	-
Total	**69,131**	**13,380**	**33,218**	**115**	**1,893**	**8,400**	**5,576**	**1,995**	**136,030**	**269,738**

Source: PLATTS database; Electricity and Cogeneration Regulatory Authority (http://www.ecra.gov.sa/en-us); Arab Union of Electricity (http://www.auptde.org/PublicationsCat.aspx?lang=en&CID=284); Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment.
Note: CC = combined cycle; DG = diesel generator; GT = gas turbine; Hydro = hydroelectricity; ISCC = integrated solar combined cycle; MW = megawatt; RE = renewable energy (includes solar photovoltaic, wind, and concentrated solar power); ST = steam turbine; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

[14] Renewable energy targets include installed capacity additions for PV, CSP, and wind. These targets are based on the National Renewable Energy Action Plans released by each country in the study.

Figure 8 presents annual energy demand figures by country for the years 2020, 2025, and 2030. The total regional electricity demand is projected to rise from 1,508 terawatt-hours (TWh) in 2020 to 2,478 TWh in 2030. In 2020, the countries with the largest energy demand are Saudi Arabia (422 TWh), Egypt (233 TWh), and Iraq (203 TWh). The same three countries are the main consumers of energy in 2030.

Figure 8. Projected Electricity Demand by Country, 2020–30, in TWh



Source: The Arab Forum for Environment and Development; Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment provided the peak power and energy demand projections in the period 2018–30. Some of the historical electricity demand figures were retrieved from the Arab Union of Electricity (AUE). The data on losses comes from the International Energy Agency (IEA).
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; TWh = terawatt-hour; UAE = United Arab Emirates; YEM = Yemen.

6.4. GENERATION TECHNOLOGY COST ASSUMPTIONS

Capital costs and the fixed and variable operation and maintenance (O&M) costs of generation technologies have a direct impact on the least-cost investment plans. Table 7 displays, for each generation technology, the type of fuel, the heat rate, the capital cost, and the fixed and variable O&M costs with assumptions used in the study. Ideally these data should be plant specific, but due to limited access to cost data sources this study instead uses generalized information based on averages for each technology.

The capital cost of a generation technology includes the cost of site preparation, construction, manufacture, commissioning, and financing of a power plant. Diesel generators have the lowest capital costs, at US$700/kilowatt (kW), and nuclear technology has the highest, at US$5,500/kW (mainly due to construction and installation expenses). Among renewable resources, decreasing module prices and higher market competition has led, over the years, to lower capital costs of solar PV (US$970/kW). CSP technology has also experienced decreasing capital costs; however, compared with other

Table 7. Technology Fuel, Heat Rate, and Cost Assumptions

Technology	Fuel	Heat Rate (MMBtu/MWh)	Capital Cost ($ million/MW)	Fixed O&M Cost ($/MW-yr)	Variable O&M Cost ($/MWh)
GT	LCR	9.75	0.81	8,100	4.05
GT	NG	9.75	0.81	8,505	4.46
CC	NG	6.00	1.22	8,370	2.24
CC	LNG	6.00	1.22	8,370	2.24
ST	HCR	9.45	2.50	10,530	2.37
ST	HFO	9.45	2.50	10,530	2.37
ST	NG	9.45	2.50	10,530	2.37
ST	Coal	8.74	2.90	32,100	4.61
DG	Diesel	9.85	0.70	10,000	10
ISCC	NG	7.45	3.77	31,180	4.42
Hydro	Water	-	2.00	14,130	-
Wind	Wind	-	1.49	22,000	-
Solar PV	Sun	-	0.97	10,000	-
Solar CSP	Sun	-	4.40	40,000	4
Nuclear	Uranium	10.48	5.50	96,200	2.21

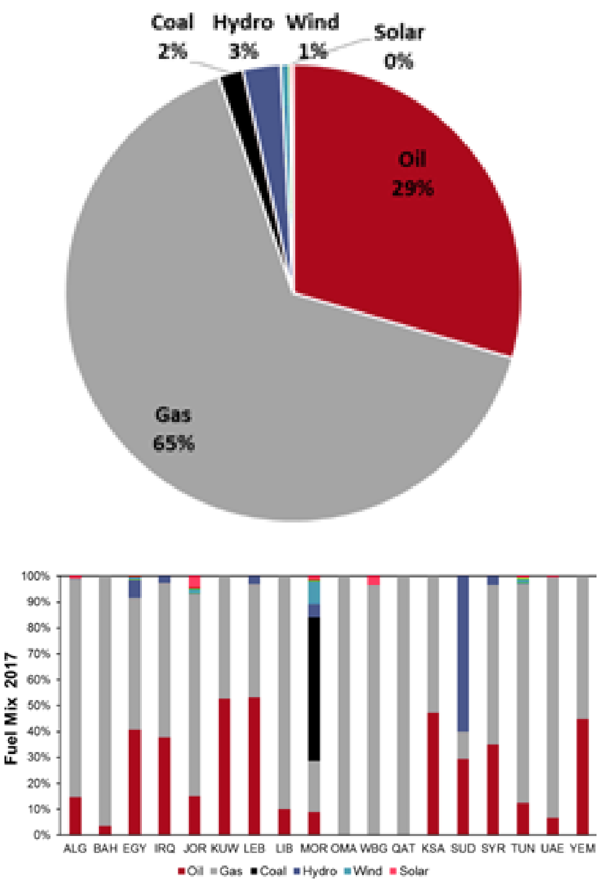
Source: Pan-Arab: Based on two previous planning studies performed by King Fahad University of Petroleum (KFUPM) in 2011, and the World Bank in 2009; IEA 2014.
Note: CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; GT = gas turbine; HCR = heavy crude oil; HFO = heavy fuel oil; Hydro = hydroelectricity; ISCC = integrated solar combined cycle; LCR = light crude oil; LNG = liquefied natural gas; MMBtu = million British thermal units; MWh = megawatt-hour; MW-yr =megawatts per year; NG = natural gas; O&M = operation and maintenance; PV = photovoltaic; ST = steam turbine.

generation technologies, it remains an expensive option for least-cost expansion.

6.5. FUEL MIX, FUEL PRICES, AND CONSUMPTION LIMITS

The Pan-Arab region relies heavily on natural gas and oil derivatives to produce electricity. As displayed in figure 9, the regional fuel mix (top), in 2017, consisted of 65 percent gas, 29 percent oil, 3 percent hydro, 2 percent coal, and less than 1 percent of wind and solar. When looking at the fuel mix on a country by country basis (bottom), it is observed that Morocco is the only country in the region that uses significant amounts of coal for electricity production and that hydro meets a significant portion of the demand in Sudan.

Figure 9. Regional and Country-by-Country Fuel Mix for the Pan-Arab Region (2017)



Source: Arab Union of Electricity 2017.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SA = Saudi Arabia; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

The study assumes (except for Cases 0 and 1) international prices for liquid and solid fuels. Table 8 presents the price assumptions for different fuels (except natural gas) by year, in $/MMBTU. The coal price increases at an average rate of 1.7 percent per year over the planning horizon to 2035. For most oil derivatives (heavy crude oil, heavy fuel oil, light fuel oil, and Arabian super light crude) and liquefied natural gas, the increase is close to 4 percent per year. In the case of shale oil, the increase is 3.3 percent per year. The study assumes that the cost of uranium remains unchanged over the planning horizon.

Table 8. Regional Prices for Liquid and Solid Fuels (US$/MMBTU)

Fuel	2018	2020	2025	2030	2035	Annual Average Growth Rate: 2018 –35 (%)
Coal	4.00	4.30	4.80	5.30	5.30	1.7
Diesel	10.00	15.20	19.10	19.10	19.10	3.9
Heavy crude oil (HCR)	7.80	11.80	14.90	14.90	14.90	3.9
Heavy fuel oil (HFO)	7.80	11.80	14.90	14.90	14.90	3.9
Light crude oil (LCr)	8.60	13.00	16.40	16.40	16.40	3.9
Arabian super light crude (SLCR)	11.80	15.80	18.90	18.90	18.90	2.8
Liquefied natural gas (LNG)	6.31	8.03	10.80	11.96	11.96	3.8
Refuse[16](REF)	4.00	4.30	4.80	5.30	5.30	1.7
Shale Oil	0.40	0.50	0.60	0.70	0.70	3.3
Uranium	0.67	0.67	0.67	0.67	0.67	0.0

Source: World Bank Commodity Market Outlook, October 2016 (Coal and Crude Oil); U.S. Energy Information Administration, spot prices for fuel oil and other products: http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
Note: MMBTU = million British thermal units.

Shale oil, an unconventional oil produced from oil shale rock fragments, is available in Jordan.

In order to assess the impact of natural gas price changes on regional electricity trade, this study considers two sets of natural gas prices by country: current prices and international prices. Table 9 presents the first set of prices, the current natural gas price by country. These prices were derived following a netback approach.[17] Most countries have natural gas prices in the range of US$4.5–5.5 per million British thermal units (MMBTU) in 2018,

[15] Million British thermal units.
[16] Refuse is unprocessed municipal solid waste.
[17] For details on the assumptions employed to estimate these prices, refer to a discussion on the value of gas, netbacks, and cost of production, by country: chapter 10 of World Bank and Ramboll (2017a).

Table 9. Current Natural Gas Price Assumptions, in US$/MMBTU, by Country

Country	2018	2020	2025	2030	2035
Algeria	4.50	4.50	5.50	6.50	6.50
Bahrain	5.00	5.00	6.00	7.00	7.00
Egypt	5.00	5.00	6.00	7.00	7.00
Iraq	4.00	4.00	4.50	5.00	5.00
Jordan	5.00	5.00	6.00	7.00	7.00
Kuwait	5.00	5.00	6.00	7.00	7.00
Lebanon	5.50	5.50	6.50	7.50	7.50
Libya	4.30	4.50	5.50	6.50	6.50
Morocco	5.00	5.00	6.00	7.00	7.00
Oman	3.50	3.50	4.50	5.00	5.00
WB&G	4.50	4.50	5.50	6.50	6.50
Qatar	5.00	5.00	6.00	7.00	7.00
Saudi Arabia	5.00	5.00	6.00	7.00	7.00
Sudan	4.00	4.00	4.50	5.00	5.00
Syria	5.00	5.00	6.00	7.00	7.00
Tunisia	5.00	5.00	6.00	7.00	7.00
UAE	5.50	5.50	6.50	7.50	7.50
Yemen	4.30	4.50	5.50	6.50	6.50

Source: World Bank staff based on World Bank and Ramboll (2017b).
Note: MMBTU = million British thermal units; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 10. International Natural Gas Price Assumptions, Based on EU Hub Prices, in US$/MMBTU, by Country

Country	2018	2020	2025	2030	2035
Algeria	5.00	5.00	6.00	7.00	7.00
Bahrain	5.50	5.50	6.50	7.50	7.50
Egypt	5.00	5.00	6.00	7.00	7.00
Iraq	5.00	5.00	6.00	7.00	7.00
Jordan	5.50	5.50	6.50	7.50	7.50
Kuwait	5.50	5.50	6.50	7.50	7.50
Lebanon	5.50	5.50	6.50	7.50	7.50
Libya	5.00	5.00	6.00	7.00	7.00
Morocco	5.50	5.50	6.50	7.50	7.50
Oman	5.00	5.50	6.50	7.50	7.50
WB&G	5.50	5.00	6.00	7.00	7.00
Qatar	5.00	5.50	6.50	7.50	7.50
Saudi Arabia	5.00	5.00	6.00	7.00	7.00
Sudan	5.00	5.00	6.00	7.00	7.00
Syria	5.50	5.50	6.50	7.50	7.50
Tunisia	5.50	5.50	6.50	7.50	7.50
UAE	5.50	5.50	6.50	7.50	7.50
Yemen	5.00	5.00	6.00	7.00	7.00

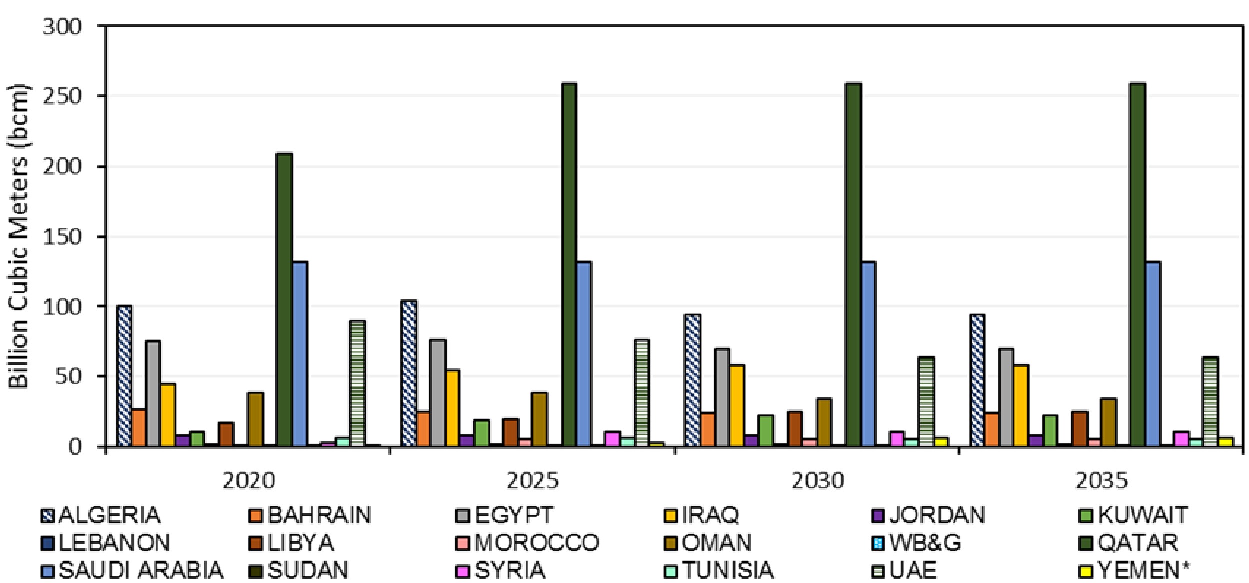
Source: World Bank staff based on World Bank and Ramboll (2017b).
Note: MMBTU = million British thermal units; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

increasing by approximately US$2/MMBTU to a range of US$6.5–7.5/MMBTU in 2030.

Table 10 presents the second set of natural gas prices considered in this study, the international gas prices by country. These prices were derived based on the spot price set on the closest gas hub to the region, the European Union (EU) Hub Price.[18] This study assumes that countries with relatively easy access to gas will be priced at the international price and countries with limited access to gas will see a transportation cost of $0.5/MMBTU added to their gas price.[19]

Countries with ample gas resources—such as Qatar, Saudi Arabia, Egypt, Iraq, and Oman—are

Figure 10. Natural Gas Consumption Limit per Year, in Billion Cubic Meters (bcm)



Source: World Bank and Ramboll 2017a; CIA: https://www.cia.gov/library/publications/the-world-factbook/geos/jo.html.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza;(*) For Yemen, these values for gas limits are an estimation based on current gas production and construction and the outlook for the end of the conflict and the recovery process (see table 35 for more details).

[18] The evolution of international gas price was taken from Table 1 of World Bank and Ramboll (2017a).
[19] See appendix C for country-specific approach.

priced at the international natural gas price, EU Hub. Economies with limited resources or access to natural gas—such as Sudan, the West Bank and Gaza, Morocco, and Lebanon—add transportation costs to their gas price.

Limits on fuel consumption are an important part of producing a model with realistic results. Specifically, for this study, it is important to apply limits to natural gas consumption given that, based on the richness of the resource in the Pan-Arab region, it is the lowest-cost option. If gas availability is left unconstrained, countries with cheap gas will consume as much as needed, leading to solutions that might be unfeasible to implement. Some countries that have plenty of natural gas reserves have limited infrastructure to generate electricity from gas, while others are running low on reserves.

Figure 10 presents the natural gas consumption limits by year, by country.[20] Qatar, Saudi Arabia, and Algeria have the highest availability of natural gas for electricity production. Sudan, West Bank and Gaza, and Morocco are the economies with the lowest gas availability.

6.6. RENEWABLE ENERGY TECHNOLOGIES

Table 11 displays the average annual capacity factor for each renewable energy technology—wind, solar PV, CSP, and hydro—for each country. Five countries exhibit wind capacity factors above 30 percent: Bahrain (36 percent), Egypt (31 percent), Jordan (30 percent), Oman (31 percent), and Saudi Arabia (38 percent). For solar PV, three countries have average capacity factors over 25 percent: Oman (26 percent), Saudi Arabia (26 percent), and Yemen (27 percent). For CSP, Yemen (20 percent) and Jordan (20 percent) have the highest capacity factors. For hydro, Egypt (55 percent) and Jordan (57 percent) stand out.

Due to the richness of renewable energy resources in the Pan-Arab region, especially wind and solar, this study applies limits on capacity deployment for these two technologies. It constrains the total capacity of wind and solar PV not to exceed 40 percent of peak demand by year, a limit applied to ensure that the transmission network will manage the intermittency of these renewable energy resources during peak hours.

Table 11. Renewable Energy Capacity Factors

Country	Wind (%)	Solar PV (%)	CSP (%)	Hydro (%)
Algeria	20	23	15	13
Bahrain	36	21	12	-
Egypt	31	24	16	55
Iraq	17	23	16	19
Jordan	30	26	20	57
Kuwait	16	21	13	-
Lebanon	16	24	19	-
Libya	16	23	16	49
Morocco	21	22	17	17
Oman	31	26	19	-
WB&G	20	22	16	-
Qatar	22	22	14	-
Saudi Arabia	38	26	19	-
Sudan	13	24	16	32
Syria	13	23	18	21
Tunisia	18	22	16	12
UAE	14	23	15	-
Yemen	18	27	20	-

Source: Solar PV capacity factor was estimated based on PVOut data on specific locations by SolarGIS, https://solargis.com/; hydro: IHA 2017; wind and CSP: based on weather data provided by SolarGIS, wind and CSP profiles were estimated using the System Advisor Model (SAM), https://sam.nrel.gov/.
Note: Capacity factor for CSP without storage. CSP = concentrating solar power; Hydro = hydroelectricity; PV = photovoltaic; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

6.7. COSTS OF FAILURE TO ACHIEVE RELIABILITY OF SUPPLY

To estimate the economic costs due to failure to maintain the reliability of supply, this study employs two criteria: the cost of unserved energy and the cost of unmet reserve capacity requirements. The latter consists of two components corresponding to two products that the system operator might require generators to provide during operation: planning reserve margin and spinning reserves. The values of these components, further explained in appendix B, are

[20] These amounts were estimated by adding the production and import balances detailed in table 2 of World Bank and Ramboll (2017a). The figures for West Bank and Gaza were assessed from World Bank (2017: figure 3). Estimated natural gas demand in the West Bank and Gaza is until 2030 (ESMAP; data provided to the report by ECO Energy). For Sudan, although it has proven natural gas reserves (CIA, Economy watch, etc.), several sources indicate that Sudan does not consume or produce natural gas. Also, it does not have operating natural-gas-fueled generation capacity.

Table 12. Cross-Border Transmission Lines Assumptions, by Country

From-To/From-To	Transfer Limits (MW) 2018	2020	2025	2030	2035	From-To/From-To	Transfer Limits (MW) 2018	2020	2025	2030	2035
ALG-MOR-ALG	400	400	1,000	1,000	1,000	JOR-SYR-JOR	350	350	800	1,000	1,000
ALG-TUN-ALG	300	300	300	300	300	KSA-GCCIA-KSA	1,200	1,200	1,800	1,800	1,800
BAH-GCCIA-BAH	600	600	1,200	1,200	1,200	KSA-YEM-KSA	0	0	500	500	500
EGY-JOR-EGY	450	450	1,100	1,100	1,100	KSA-OMA-KSA	0	0	0	1,000	1,000
EGY-KSA-EGY	0	0	3,000	3,000	3,000	KSA-KUW-KSA	0	0	0	1,000	1,000
EGY-LIB-EGY	180	180	550	1,000	1,000	KUW-IRQ-KUW	0	0	0	1,000	1,000
EGY-SUD-EGY	200	200	1,200	1,200	1,200	KUW-GCCIA-KUW	1,200	1,200	1,800	1,800	1,800
EGY-WBG	25	25	200	200	200	LEB-SYR-LEB	470	470	1,200	1,200	1,200
IRQ-KSA-IRQ	0	0	500	1,000	1,000	LIB-TUN-LIB	0	0	500	1,000	1,000
IRQ-SYR-IRQ	227	227	227	227	227	OMA-UAE-OMA	400	400	400	400	400
JOR-IRQ-JOR	0	0	500	500	500	QAT-GCCIA-QAT	750	750	1,800	1,800	1,800
JOR-KSA-JOR	0	0	500	1,000	1,000	UAE-GCCIA-UAE	900	900	1,800	1,800	1,800
JOR-WBG	40	40	200	200	200						

Source: The Arab Forum for Environment and Development; Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; Moroccan Ministry of Energy, Mining, Water and Environment; and Mediterranean Transmission System Operators (Mediterranean Project 1).

Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; GCCIA = Gulf Cooperation Council Interconnection Authority; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; MW = megawatt; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

assumed in this study as follows:

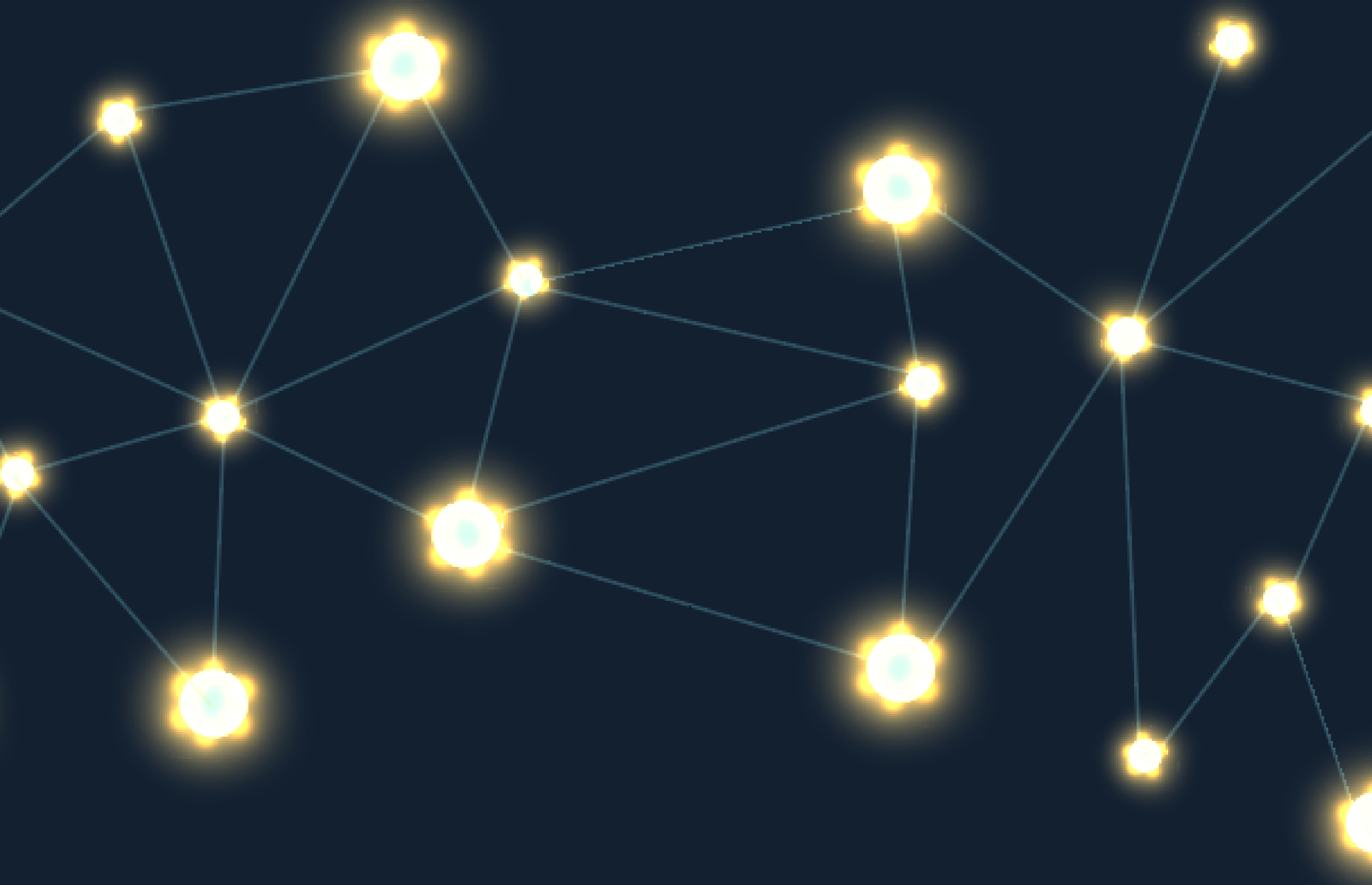
- Unserved energy cost: $500/MWh
- Planning reserve shortfall cost: $5,000/MW
- Spinning reserve shortfall cost: $1,000/MWh

6.8. CROSS-BORDER INTERCONNECTIONS

Table 12 displays each cross-border transmission line considered in this study, including both existing and planned lines, commissioning dates, and transfer limits. There are 10 transmission lines that are under construction or planned. This includes a 3,000 MW Egypt⇆Saudi Arabia line that is to be commissioned in 2022.

The following chapter details the results of the study, focusing on the potential benefits of engaging in regional electricity trade among the Pan-Arab countries using the assumptions described in this chapter.

7 RESULTS



Using the Electricity Planning Model (EPM), this study has generated projections of how the Pan-Arab region's electricity sector will grow under different assumptions. The modeling results provide insights into how electricity trade will impact important areas of the region's power system, such as total capacity and investment, total system costs, cost of electricity, the benefits of bilateral trade, carbon emissions, and transmission line utilization rates.

The model planning horizon comprises the period 2018–35. Model input data, for the years 2018–30, were compiled from various sources: the Arab Forum for Environment and Development; Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; the Egyptian Electricity Holding Company; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and the Moroccan Ministry of Energy, Mining, Water and Environment. Some of the historical electricity demand and capacity figures were retrieved from the Arab Union of Electricity and the International Energy Agency. The projection of relevant input parameters, such as energy demand, for the period 2030–35 was estimated by using the same growth rates that are projected for the period 2025–30.

7.1. PEAK DEMAND AND INSTALLED CAPACITY PROJECTIONS

Table 13 presents the projected total installed capacity based on the results for Case 0 (which assumes that no electricity trade takes place, gas prices for electricity production remain subsidized, and that each country independently makes its own capacity investments to satisfy its projected demand) along with peak demand by country.

7.2. CAPACITY ADDITIONS AND INVESTMENT COSTS

Electricity trade can defer capacity additions through more efficient use of generation assets. This can alleviate the financial strain on the Pan-Arab region's utilities and treasuries, since when trade is enabled, countries can defer capital investments in electricity infrastructure that would otherwise be required for them to meet growing demand. Table 14 presents the capacity additions required for each case and the cumulative investment figures.

Table 13. Projected Peak Demand and Total Installed Capacity by Country, in GW, Case 0 (Base)

	2018		2020		2025		2030		2035	
Country	Peak Demand	Installed Capacity	Peak Demand	Installed Capacity	Peak Demand	Installed Capacity	Peak Demand	Installed Capacity	Peak Demand	Installed Capacity
Algeria	12.9	20.6	15.2	27.9	18.6	27.9	22.4	33.6	27.3	36.2
Bahrain	3.6	3.9	4.1	4.7	4.8	8.1	5.7	8.9	6.8	9.4
Egypt	31.6	38.9	40.4	52.2	53.2	69.2	69.1	90.9	90.5	113.9
Iraq	24.0	30.3	28.0	39.8	41.0	66.4	60.0	85.1	76.8	102.5
Jordan	3.6	4.8	4.1	6.1	5.3	7.1	6.7	8.4	8.9	10.4
Kuwait	13.6	18.8	16.4	20.7	20.9	25.4	23.2	29.2	26.4	32.6
Lebanon	3.6	2.2	3.6	2.7	3.8	5.8	4.4	7.3	5.1	7.7
Libya	5.0	9.9	6.3	9.2	7.2	17.8	8.2	19.7	9.4	20.4
Morocco	6.5	8.8	7.5	17.0	9.5	21.8	11.9	24.0	15.1	25.3
Oman	7.3	9.6	9.3	11.2	11.9	12.7	15.2	16.7	19.5	20.8
WB&G	1.4	1.2	1.6	1.4	2.1	3.3	2.6	3.9	3.2	3.7
Qatar	7.8	11.9	8.7	11.0	9.8	13.1	10.7	13.1	11.7	12.1
Saudi Arabia	69.9	84.8	76.9	90.2	94.1	126.1	109.6	139.4	124.3	154.9
Sudan	3.2	4.5	5.5	5.8	10.1	11.2	18.6	15.8	34.5	19.6
Syria	5.7	8.7	6.9	10.5	8.3	14.3	10.0	12.6	12.1	13.3
Tunisia	3.8	6.1	4.6	6.8	5.9	7.7	7.0	9.3	8.8	10.9
UAE	23.4	31.6	34.0	34.0	45.5	48.4	58.1	62.9	69.6	73.6
Yemen	1.4	1.5	1.7	1.6	2.2	2.4	2.7	2.6	3.7	2.9
Total Capacity		298.07		352.82		488.74		583.53		670.19

Source: World Bank staff based on EPM output.
Note: GW = gigawatt; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 14. Investment Requirements for Total Capacity Additions, by Case

Scenario	Capacity Addition 2018-35 (GW)	Capacity Investment 2018-35 (NPV in $ million)[a]	Baseline Comparison (relative to Case 0) $ million	% change
Case 0	361	262,672	-	-
Case 1	350	251,865	(10,817)	-4%
Case 2	379	365,749	103,077	39%
Case 3	364	367,513	104,841	40%
Case 4	553	745,058	482,387	184%
Case 5	490	624,877	362,206	138%
Case 6	274	252,568	(10,104)	-4%

Source: World Bank staff based on EPM output.
Note: Each of the capacity investment figures in this table is the sum of the discounted values of investment costs for each year through 2035. Yearly investment costs used in the calculation are not annualized.
GW = gigawatt; NPV = net present value.

In Case 0, the baseline scenario, 361 gigawatts (GW) of new capacity will be added by 2035, requiring a cumulative investment of US$262.7 billion in generation. When electricity trade is introduced under Case 1, which still uses the current gas prices, the capacity additions and investment decrease. Cumulative investment falls by US$10.8 billion, a 4 percent reduction, and capacity additions are reduced by 11 GW.

The use of international gas prices results in higher capacity additions and investment. In Cases 2 and 3, the assumed transition to international gas prices (EU Hub prices) is accompanied by increased cumulative investment needs. This is due to the displacement of gas-fired technology by more capital-intensive options requiring no fossil fuel inputs. Specifically, Case 2 requires US$103.1 billion more in cumulative investment than the baseline, a 39 percent increase. Case 3 requires US$104.8 billion more than the baseline, a 40% increase. However, this is more than offset by a reduction in other costs as discussed in the next subsection on total system costs.

In Cases 4 and 5, the introduction of a cap on carbon emissions further increases the required capacity additions and total investments. Relative to other cases, the carbon cap scenarios are marked by a substantial uptake of the capital-intensive concentrating solar power (CSP) technology. Case 4 would require 553 GW in additional capacity and a cumulative investment of US$482.4 billion more than the baseline, a 184 percent increase. Relative to Case 4, the cumulative investment figures are reduced in Case 5 when trade is introduced. Still, Case 5 requires US$362.2 billion more in cumulative investment than the baseline.

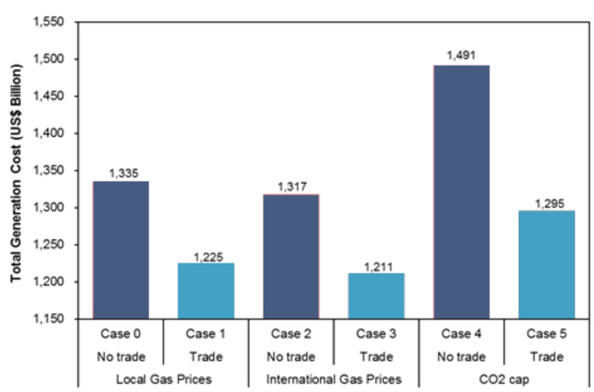
Case 6, which assumes a lower electricity demand than all the other cases, stands out as the least capital-intensive one. The required installed capacity is 87 GW less than in the baseline Case 0, and the investment need is 4% below the baseline.

When the cases with trade and without trade are compared, using the same time horizon (2018–35), it turns out that Case 1 saves 11 GW of installed capacity and US$10.8 billion in capital costs relative to Case 0; Case 3 saves 15 GW but increases the capital costs by US$1.8 billion versus Case 2; and Case 5 saves 63 GW and as much as U$120.2 billion in capital costs versus Case 4.

7.3. TOTAL SYSTEM COSTS

Introducing electricity trade reduces total system costs in all scenarios. In doing so, it can save the Pan-Arab region's utilities and treasuries money that can be allocated to other policy

Figure 11. Total System Cost Comparisons (US$ billion)



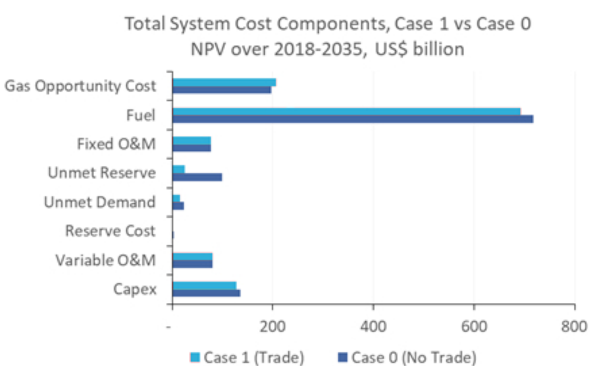
Source: World Bank staff based on EPM output.
Note: CO_2 = carbon dioxide; EU = European Union.

priorities. Figure 11 displays the total costs for each scenario. The dark-blue bars represent the cases with no trade and the light-blue bars represent the cases with trade.

The cost components comprising the total system costs are shown in figures 12, 13, and 14. The total system costs consist of a typical set of electricity generation costs and, for Cases 0 and 1, one specific type of opportunity cost related to the cost of subsidy on natural gas being used as fuel for electricity generation. Generation costs consist of annualized capital expenditure (CAPEX), fuel costs, fixed and variable operation and maintenance (O&M) costs, and the costs to procure spinning reserves, as well as penalties for unmet demand (or "unserved energy") and unmet reserve requirements. The latter penalty occurs when the system fails to comply with the required reserve capacity, including spinning reserves. Finally, the mentioned opportunity cost is related to using natural gas for electricity production instead of selling it for export revenue.

As shown in figure 11, Case 0 has a total system cost of US$1,335 billion and this decreases by US$110 billion, or 8.2 percent, with the introduction of electricity trade in Case 1. Figure 12 shows the cost components contributing to this result. The capital expenditures decrease to some extent, as trade enables the region to invest in and access cheaper generation sources. Fuel costs are reduced as the system transitions from expensive liquid fuels to gas. The costs to meet the reserve requirements fall especially sharply as trade enables greater access to reserves through cross-border transmission interconnections.

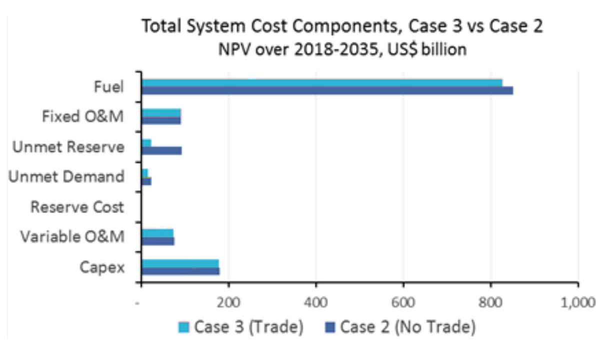
Figure 12. Total System Costs, Case 1 vs. Case 0



Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; NPV = net present value; O&M = operation and maintenance.

The benefits from trade have similar proportions in the scenarios that assume a transition of the region to international gas prices. While Case 2 has a total system cost of US$1,317 billion, this decreases by US$107 billion, or 8.1 percent, with the introduction of trade in Case 3. The capital expenditures are slightly lower with trade, even as more renewables are deployed when gas is priced at international levels. This is because the difference in total capacity additions, 15 GW less in Case 3, offsets the higher cost of investing in more renewables. Moreover, this reduction in cost is accompanied by reductions in other cost components, notably the fuel costs and unmet capacity reserves, working in favor of the scenario with trade (figure 13). Unlike the scenarios with current gas prices, the opportunity cost of using gas for electricity (i.e., gas subsidy cost) is no longer included since the domestic and international gas prices are equalized.

Figure 13. Total System Costs, Case 3 vs. Case 2



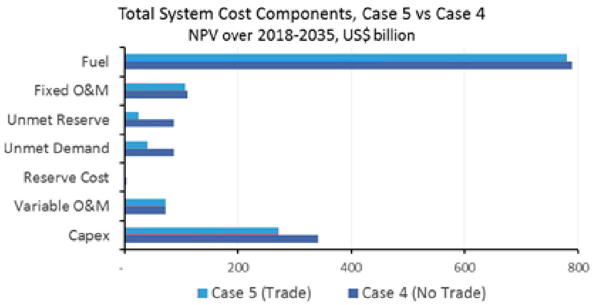
Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; NPV = net present value; O&M = operation and maintenance.

Finally, when gas price liberalization is also accompanied by the introduction of carbon caps, the benefits from trade are even greater. As was shown in figure 11, Case 4 has total system costs of US$1,491 billion. This decreases by US$196 billion, or 13.1 percent, with the introduction of trade in Case 5. It must be noted that the two

[21] The annualization of the capital investment costs (CAPEX) is a built-in feature of the calculation of total system costs in the EPM. The model applies an annualization formula to every investment cost value throughout the planning horizon. The advantage of annualization is that, for any given year, the CAPEX cost component can be more easily compared with the running cost components such as fuel and O&M. A notable disadvantage is that the net present value (NPV) of a stream of annualized CAPEX values over a certain time period (for example, 2018–35) is not directly comparable with the NPV of a stream of full values of investment costs for the same time period, when the full values are included without annualization.

cases with carbon caps have much higher CAPEX costs than all other scenarios. This is because carbon caps require higher levels of deployment of carbon-free technologies such as wind and CSP that have high CAPEX but no fuel requirements.

Figure 14. Total System Costs, Case 5 vs. Case 4



Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; NPV = net present value; O&M = operation and maintenance.

7.4. IMPACT ON ELECTRICITY COSTS

The introduction of electricity trade impacts the cost of electricity in each country. In some cases, it significantly reduces the cost of electricity, but other countries will experience increases in their electricity costs.

When trade is enabled with current gas prices, most countries see only a marginal change in their current cost of electricity (table 15). Some countries see a larger increase in the cost of their electricity. Oman and Qatar, for example, see electricity costs increase for each time period through 2035. In Qatar, costs will increase by 33 percent in 2025 and by 25 percent in 2035. On the other hand, Jordan, Lebanon, Sudan, and Yemen may see sharply decreased costs by 2025. The countries that have cost increases are mainly gas-exporting countries. They have an incentive to invest more in generating capacity due to their ability to generate electricity at lower prices. However, as they install more generation, the cost of electricity also rises as they may be investing in progressively more expensive generation technologies.

These countries must invest more heavily in generation resources that are required in order to generate additional electricity to export to countries that lack the generation capacity or resources to meet their load in a cost-effective manner. However, the exporting countries also receive revenues from this trade, which can be spent on other policy priorities such as social programs.

When trade is enabled with international gas prices, the trend is similar. Countries that have cost increases are mainly gas-exporting countries and, on average, countries with low gas availability will see their cost of electricity decrease, but cost changes are not as pronounced (table 16). This is because when international gas prices are used instead of current gas prices, the gas prices are homogeneous across the region. When imbalances

Table 15. Difference in Electricity Costs When Trading under Case 1: Current Gas Prices

Country	2018 (%)	2020 (%)	2025 (%)	2030 (%)	2035 (%)
Algeria	-0.32	2.56	3.96	-1.17	-0.87
Bahrain	-7.72	5.60	0.00	-6.36	-8.27
Egypt	-0.90	-1.27	0.92	1.47	1.70
Iraq	-5.76	0.00	-0.23	-0.20	-0.18
Jordan	6.64	-0.94	-25.63	-22.37	-5.13
Kuwait	-0.94	-11.78	1.76	0.20	0.42
Lebanon	-48.10	-26.38	-36.73	7.29	11.53
Libya	0.00	-0.20	-0.02	1.52	0.50
Morocco	23.44	31.67	-11.44	2.30	2.56
Oman	0.77	0.65	5.35	0.22	3.88
WB&G	-1.03	0.00	0.02	0.84	15.47
Qatar	5.49	4.10	32.59	23.12	25.50
Saudi Arabia	2.35	-1.24	-6.17	-5.31	8.46
Sudan	-6.28	-7.13	-40.88	-26.39	-15.82
Syria	-1.03	-11.05	7.70	2.75	-0.69
Tunisia	2.75	-4.44	-0.94	-54.65	-24.59
UAE	0.21	-25.94	1.00	2.29	2.43
Yemen	0.00	-3.69	-32.80	-43.20	-35.89

Source: World Bank staff based on EPM output.
Note: Negative values indicate there is a reduction in annual marginal cost of electricity. UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 16. Difference in Electricity Costs when Trading under Case 3: International Gas Prices

Country	2018 (%)	2020 (%)	2025 (%)	2030 (%)	2035 (%)
Algeria	-0.31	2.56	0.99	-0.52	-0.63
Bahrain	-8.04	4.23	8.95	2.91	0.66
Egypt	0.47	-1.13	0.33	1.07	0.65
Iraq	-3.76	2.26	0.31	-0.50	0.27
Jordan	2.81	-4.58	-23.87	-15.43	-8.79
Kuwait	-0.39	-6.33	-3.71	-0.62	1.07
Lebanon	-48.06	-25.88	-36.95	7.57	10.86
Libya	0.00	-0.80	0.21	0.19	0.00
Morocco	-22.97	31.01	-9.79	2.12	0.34
Oman	0.41	0.58	8.95	4.55	2.39
WB&G	-0.99	0.00	0.02	2.09	15.81
Qatar	4.21	2.97	21.51	11.70	5.09
Saudi Arabia	-1.94	-1.49	-0.96	-0.85	-2.25
Sudan	-6.28	-7.13	-40.86	-26.26	-15.82
Syria	0.87	-11.05	7.54	0.39	-1.44
Tunisia	2.78	-4.31	0.17	-52.64	-24.54
UAE	0.23	-25.83	-1.64	2.33	3.01
Yemen	0.00	1.03	-27.35	-38.88	-33.82

Source: World Bank staff based on EPM output.
Note: Negative values indicate there is a reduction in annual marginal cost of electricity. UAE = United Arab Emirates; WB&G = West Bank and Gaza

like this are reduced, it is more expensive for countries with ample gas availability to produce electricity for export, and marginal cost differences among countries will not be as significant.

In general, countries seeing cost increases in the earlier years may find their costs eventually decreasing. The temporary increase is mainly driven by the need to overcome an initial transmission infrastructure deficit that hinders the optimal levels of trade. In 2020–25, as many new transmission lines are commissioned, broader trade within the region will bring the costs down, with electricity importers being the most direct beneficiaries.

7.5. SHARED BENEFITS FROM BILATERAL TRADE

The form of economic benefits discussed in this subsection is a useful additional metric to gauge the benefits from trade. These are meant to complement (but not to replace) the more comprehensive account of the benefits based on total system cost savings discussed earlier. Its advantage is relative simplicity and the possibility to apply the method to a variety of time frames. For the short term, it can produce useful results based on current data rather than relying on long-term projections. However, it can also be applied for the 2018–35 period considered in this report. The limitations of the method are due to the omission of potentially important variables (e.g., system reliability costs) exogenous to the inputs in its basic formula.

As was explained in chapter 3, electricity trade can bring substantial economic benefits to the region through a relatively simple process of utilizing the differentials in the marginal costs of electricity generation in different countries. In the simplest case of bilateral trade, the shared benefit from trade is the product of the cost differential and the volume of electricity traded.

Shared Benefit from Trade = $(C_i - C_e) \times Q$
Where:

- C_i, in \$/megawatt-hour (MWh), is the marginal cost of electricity of the importing country without trading;
- C_e, in \$/MWh, is the marginal cost of the exporting country without trading; and
- Q, in MWh, is the quantity (or volume) of electricity traded over a time period.

In a calculation done for this report (see appendix E for details), trade was assumed to take place through the interconnections already existing as well as new ones built over the period to 2035. For simplicity, it was assumed that the benefits of trade were always divided equally between the trading countries, which is the case when the price P of the trade is set at midpoint between the importer's and exporter's production costs, that is, $P = (C_i + C_e)/2$. Table 17 shows the aggregate results from the calculation.

Figure 15 shows the annual shared economic benefits of the exchanges of electricity for Case 1, Case 3, Case 5, and Case 6, for specified years (2020, 2025, 2030, and 2035). Case 5 exhibits the highest shared economic benefits among all the cases, with annual benefits above \$10 billion in some countries (whereas the highest annual benefits for all other cases stays below \$2.5 billion). This is because to achieve the CO_2 limits imposed in Case 5, the price of electricity increases in the region as countries have to invest in higher-cost low-carbon technologies.

While all countries receive the benefits from trade, Egypt, Sudan, Saudi Arabia, Tunisia, and Libya have

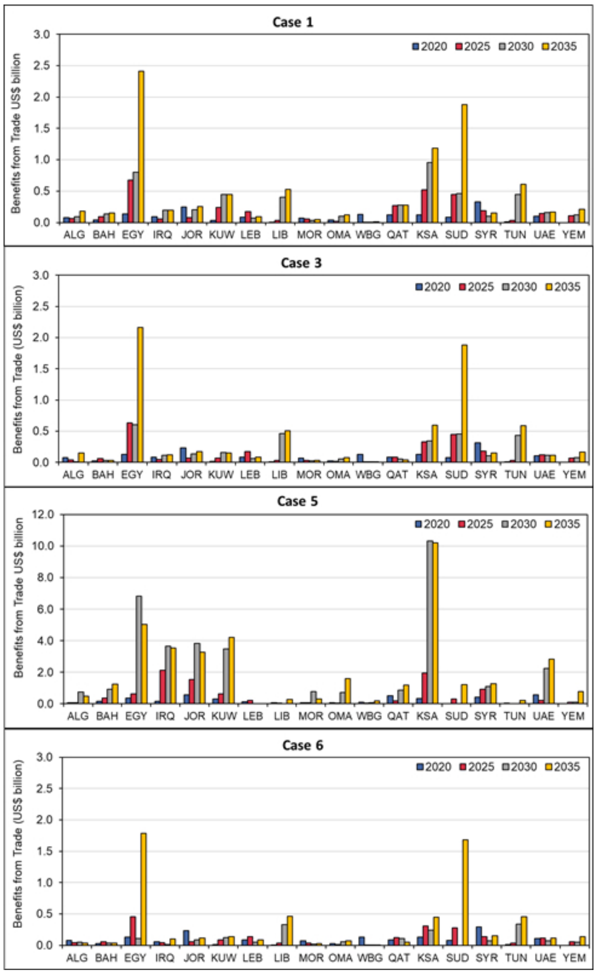
Table 17. Shared Economic Benefits of Electricity Trade among the Arab Countries

Cases	Shared Benefits from Trade, NPV over 2018–2035, \$ Billion
Case 0: Natural gas current prices, no electricity trading	N/A
Case 1: Natural gas current prices, electricity trading	40.3
Case 2: Natural gas international prices, no electricity trading	N/A
Case 3: Natural gas international prices, electricity trading	32.2
Case 4: Natural gas international prices, no electricity trading, CO_2 emissions limit	N/A
Case 5: Natural gas international prices, electricity trading, CO_2 emissions limit	150.0
Case 6: Natural gas international prices, electricity trading, CO_2 emissions limit	25.3

Source: World Bank staff based on EPM output.
Note: CO2 = carbon dioxide; NPV = net present value; N/A = not applicable; EE = energy efficiency; DR = demand response.

the highest figures for the benefits of trade in all cases except Case 5; Sudan and Tunisia receive these benefits, mainly as importers, from exchanging electricity with Egypt and Libya, respectively. With carbon caps (Case 5), Saudi Arabia emerges as the largest beneficiary, in years 2030 and 2035, because of the increase of the utilization of the new cross-border lines coupled with a significant increase in the cost of electricity in the countries engaging in exchanges with it, as they have to invest in higher-cost, low-carbon technology, such as CSP, to comply with the CO_2 emission limits.[22]

Figure 15. Shared Economic Benefits of Trade for Cases 1, 3, 5, and 6



Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; mm = million; MOR = Morocco; OMA = Oman; WBG= West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

[22] For details on the shared economic benefit of bilateral trade estimates for all the cases, refer to appendix E.

7.6. COMMERCIAL VALUE OF TRADE

Commercial value of bilateral trade is the other important metric to complement, rather than replace, the economic value of the benefits based on the total system cost savings. The formula for the commercial value of trade is VoT = (Ci + Ce)/2 x Q, using the same inputs as in the shared benefits formula.

Based on the projected generation costs and quantities of electricity flowing through the lines, table 18 shows that the value of electricity traded can be between US$59.5 billion and US$166.6 billion.

It is important to stress the commercial (or financial, rather than economic) nature of the value of trade discussed here. Since the exporter's revenue is the importer's cost, the region-wide monetary net value of trade at any time is zero. However, the metric is still useful as a measure of the overall market activity in the region, whether its volume is measured as the total exporters' revenue or the total importers' cost. On an absolute as well as net basis, it also shows each country's position in exports and imports.

Figures 16–19 display the value of trade as the annual exporters' revenue and importers' cost, in US$ billion, for the years 2020, 2025, 2030, and 2035 for Cases 1, 3, 5, and 6. For most cases, Saudi Arabia is a major exporter, both in absolute and net terms, especially in the later years of the analysis: 2025–30 and afterwards. Egypt is a major player as well, with export and import transactions rivaling those of Saudi Arabia and even exceeding them in absolute terms in Case 6 (energy efficiency). Applying carbon caps, Case 5, has an important effect on defining a country as a net importer or exporter. For instance, for most cases, Algeria, Oman, Qatar, Iraq, Libya, and Syria are considered net exporters and Morocco and Jordan are considered net importers; however, once CO_2 targets are required, their role as importers/exporters will change.[23] This is because of their availability of carbon-free generation technologies.

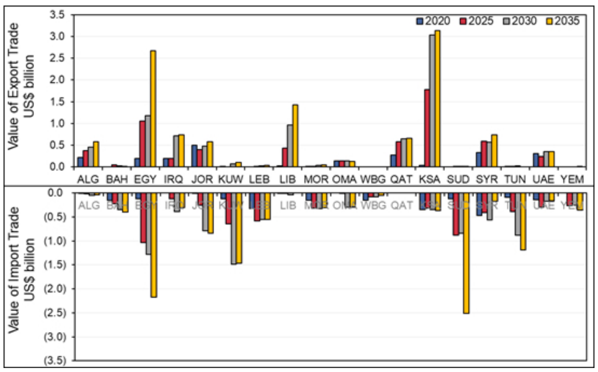
[23] It is important to note that Syria's power system has to be further evaluated to reflect the realities of system costs, supply availability, demand, and level of damage caused by conflict in the country.

Table 18. Commercial Value of Electricity Trade (Export or Import Value) among the Arab Countries

Cases	Value from Trade, NPV over 2018–2035, $ Billion
Case 0: Natural gas current prices, no electricity trading	N/A
Case 1: Natural gas current prices, electricity trading	59.5
Case 2: Natural gas international prices, no electricity trading	N/A
Case 3: Natural gas international prices, electricity trading	62.9
Case 4: Natural gas international prices, no electricity trading, CO_2 emissions limit	N/A
Case 5: Natural gas international prices, electricity trading, CO_2 emissions limit	166.6
Case 6: Natural gas international prices, electricity trading, CO_2 emissions limit	59.6

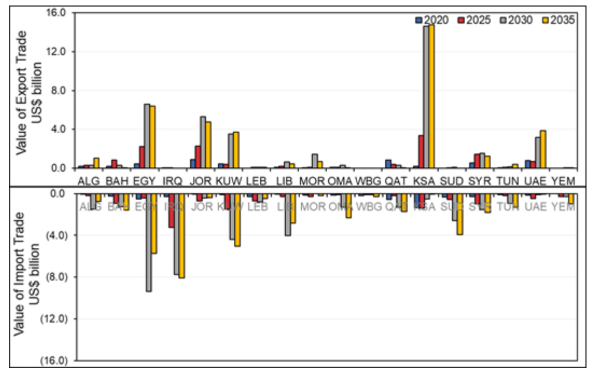
Source: World Bank staff based on EPM output.
Note: CO2 = carbon dioxide; NPV = net present value; N/A = not applicable; EE = energy efficiency; DR = demand response.

Figure 16. Value of Trade for Case 1 for the years 2020, 2025, 2030, and 2035



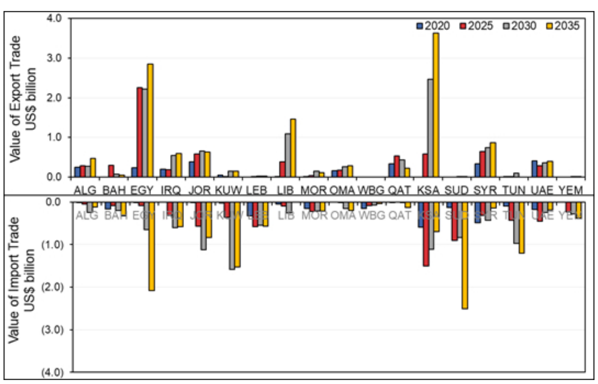
Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; mm = million; MOR = Morocco; OMA = Oman; WBG= West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 18. Value of Trade for Case 5 for the years 2020, 2025, 2030, and 2035



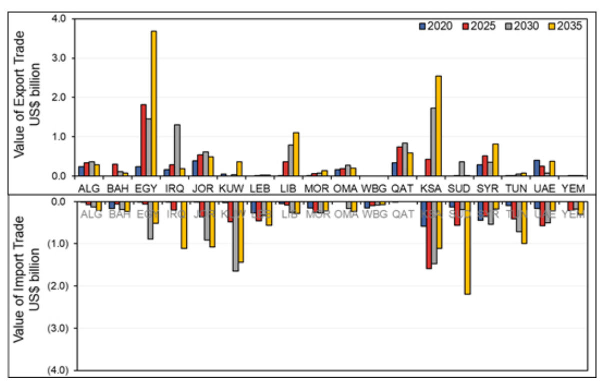
Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; mm = million; MOR = Morocco; OMA = Oman; WBG= West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 17. Value of Trade for Case 3 for the years 2020, 2025, 2030, and 2035



Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; mm = million; MOR = Morocco; OMA = Oman; WBG= West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 19. Value of Trade for Case 6 for the years 2020, 2025, 2030, and 2035

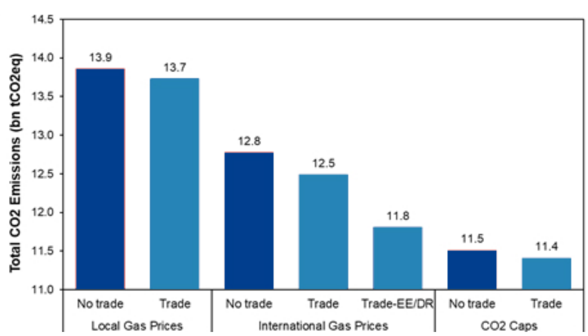


Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; mm = million; MOR = Morocco; OMA = Oman; WBG= West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

7.7. IMPACT OF TRADE ON CO_2 EMISSIONS

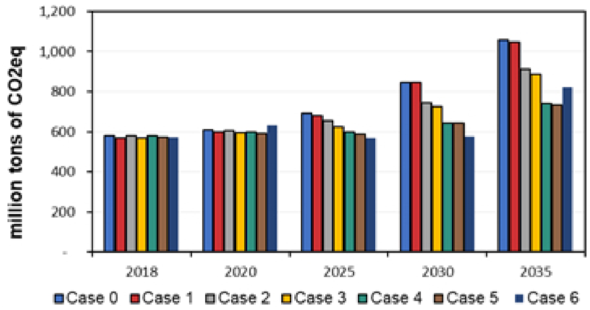
The impact of trade on CO_2 emissions in the region was also considered. As figure 20 shows, the impact of trade per se is moderately positive (that is, it leads to moderate reductions in CO_2 emissions). However, it is less pronounced than the impact of the other key factors involved, such as the transition to international gas prices, or the introduction of CO_2 emissions limits. When trade is introduced while the gas prices are at current levels, the CO_2 emissions reduction is almost negligible. It is more significant when the gas prices are set at international levels and even more so once energy efficiency (EE) and demand response (DR) measures are also adopted. When, in addition to considering international gas prices, CO_2 emissions caps are introduced, the impact of trade is small again, but the impact of the CO_2 emission limits themselves is quite significant.

Figure 20. Total CO2 Emissions in 2018–35



Source: World Bank staff based on EPM output.
Note: bn tCO_2eq = billion tons of carbon dioxide equivalent; CO_2 = carbon dioxide; EE = energy efficiency; DR = demand response.

Figure 21. Total CO2 Emissions by Case, in Million Tons CO_2 Equivalent, 2018–35



Source: World Bank staff based on EPM output.
Note: CO2eq = carbon dioxide equivalent.

If the CO_2 emissions under international gas prices are compared with those under the current domestic prices, the emission savings amount to 1.08 billion tons of CO_2 equivalent when there is no trade, to about 1.24 billion tons when there is trade, and to 1.92 billion tons after also adopting energy efficiency and demand response measures. If, in addition to international gas prices, CO_2 caps are introduced, the additional savings will amount to 1.26 billion tons of CO_2 without trade and 1.08 billion tons with trade.

The growth of CO_2 emissions over time seems inevitable (figure 21) but the growth rate depends on the case analyzed, with the "greener" cases (Case 4 and Case 5) yielding more moderate emission growth rates. For example, the average annual emission growth rate for Case 5 is 1.5 percent, versus 3.6 percent in Case 0. Although the average annual emission growth rate for Case 6 is 2.2 percent, higher than in Case 5, figure 21 shows that in the years 2025 and 2030 CO_2 emissions for Case 6 are lower than for Case 5.

Table 19. Total Installed Capacity by Technology, MW

	Year 2018	Year 2035 Case 0	Year 2035 Case 1	Year 2035 Case 2	Year 2035 Case 3	Year 2035 Case 4	Year 2035 Case 5	Year 2035 Case 6
CC	106,392	382,073	374,850	345,241	330,932	355,277	343,749	291,897
CSP	525	2,244	1,366	2,278	2,278	161,809	98,712	1,382
GT	93,298	94,067	83,940	91,102	91,102	84,073	77,821	79,589
Hydro	11,382	10,348	10,348	10,348	10,348	12,458	12,458	10,348
DG	4,461	1,388	1,420	1,386	1,386	1,393	1,383	1,351
PV	1,345	72,580	69,214	69,160	69,160	64,669	65,666	60,414
ST	75,358	51,738	50,496	51,738	51,738	51,110	51,110	50,496
Wind	2,309	22,033	34,938	46,205	46,205	55,507	56,283	34,719
Nuclear	-	11,602	10,768	48,796	55,131	56,028	71,751	31,210
ISCC	-	-	-	-	-	-	-	-
Coal	3,005	22,083	22,083	22,135	22,122	20,095	20,614	22,051
TOTAL:	**298,075**	**670,191**	**659,422**	**688,389**	**673,101**	**862,419**	**799,547**	**583,457**

Source: World Bank staff based on EPM output.
Note: CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; GT = gas turbine; Hydro = hydroelectricity; ISCC = integrated solar combined cycle; MW = megawatt; PV = photovoltaic; ST = steam turbine.

The dynamics of CO_2 emissions in Cases 1 to 3 and Case 6 are driven to a large extent by the changing mix of generation technologies. Applying CO_2 emissions policy (such as carbon caps in Cases 4 and 5) will provide a path for controlling these emissions. Tables 19 and 20 show the generation mix in absolute terms (in MW) and as a share of total installed capacity. Wind, solar PV, and CSP are the three zero-emission renewable energy sources in the calculation.

As table 20 shows, the share of zero-emission renewable energy technology is expected to increase dramatically in all six cases considered, albeit starting from a very low base in 2018.

Table 21 shows the average annual growth rates in total installed capacity over the period 2018–35. While total installed capacity grows at about 4.0–6.4 percent per year, renewable energy sources grow mostly at double-digit rates, although CSP has rates below 10 percent in Cases 1–3 and 6.

Figure 22 takes the total energy generated by technology by case, Cases 0 to 5, to illustrate the dynamics of penetration of the three mentioned renewable energy sources in the total energy output over time. It is observed that renewable energy output increases with higher natural gas prices (comparing Case 2 versus Case 0 and Case 3 versus Case 1), as higher fuel prices make these technologies more economically competitive. When a carbon policy is introduced (Cases 4 and

Table 20. Share of Total Installed Capacity by Technology, including Renewable Energy Sources

	Year 2018 (%)	Year 2035 Case 0 (%)	Year 2035 Case 1 (%)	Year 2035 Case 2 (%)	Year 2035 Case 3 (%)	Year 2035 Case 4 (%)	Year 2035 Case 5 (%)	Year 2035 Case 6 (%)
CC	35.7	57.0	56.8	50.2	49.2	41.2	43.0	50.0
CSP	0.2	0.3	0.2	0.3	0.2	18.8	12.3	0.2
GT	31.3	14.0	12.7	13.2	12.0	9.7	9.7	13.6
Hydro	3.8	1.5	1.6	1.5	1.5	1.4	1.6	1.8
DG	1.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PV	0.5	10.8	10.5	10.0	10.5	7.5	8.2	10.4
ST	25.3	7.7	7.7	7.5	7.5	5.9	6.4	8.7
Wind	0.8	3.3	5.3	6.7	7.4	6.4	7.0	6.0
Nuclear	0.0	1.7	1.6	7.1	8.2	6.5	9.0	5.3
ISCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	1.0	3.3	3.3	3.2	3.3	2.3	2.6	3.8
Total:	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
RES, MW	4,179	96,858	105,518	117,643	121,864	281,985	220,661	96,515
RES, %	1.4	14.5	16.0	17.1	18.1	32.7	27.6	16.5

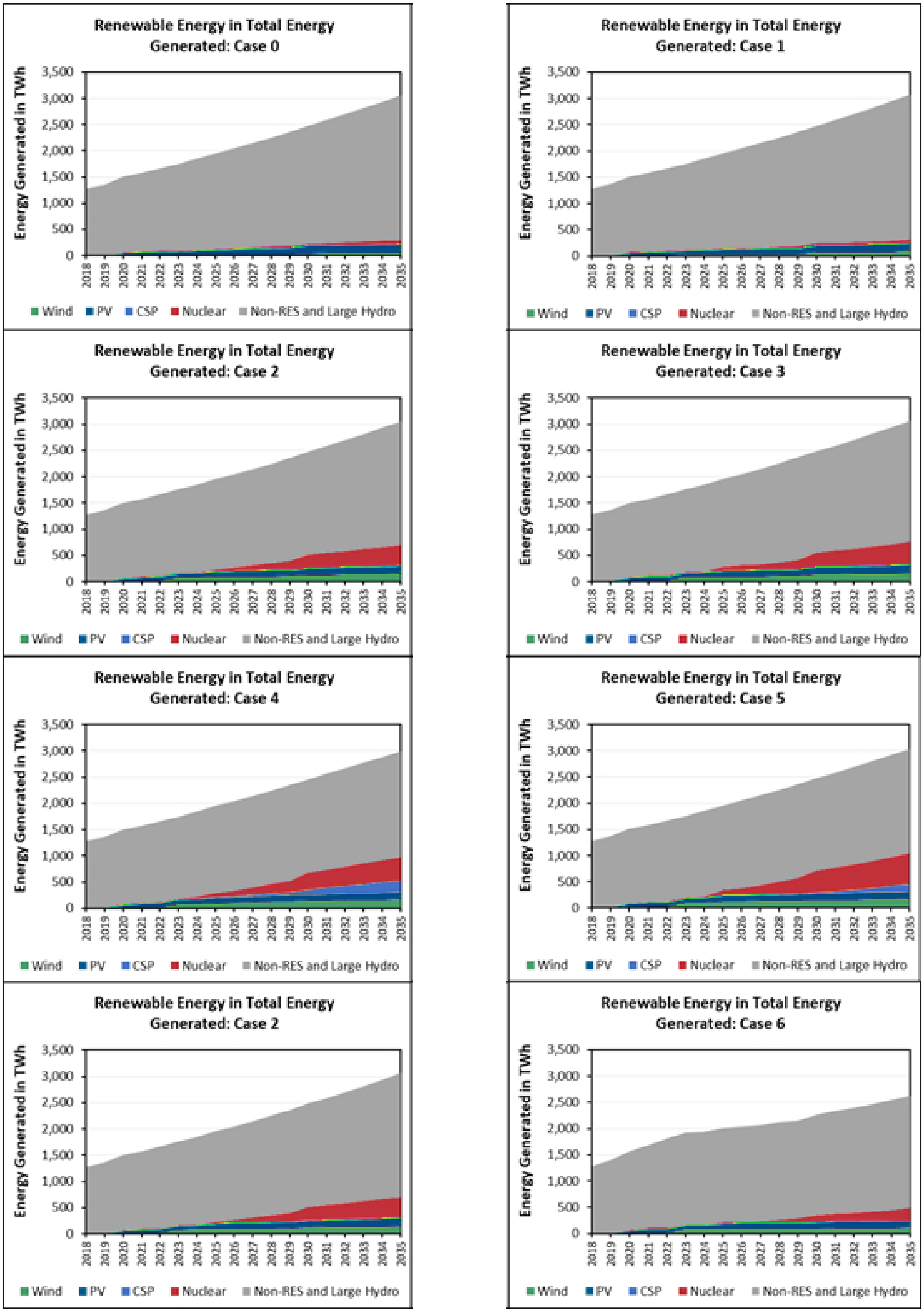
Source: World Bank staff based on EPM output.
Note 1: CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; GT = gas turbine; Hydro = hydroelectricity; ISCC = integrated solar combined cycle; PV = photovoltaic; RES = renewable energy sources; ST = steam turbine.
Note 2: The solar PV potential in the report is based on the solar mapping results estimated by the World Bank for every country. However, the ability to realize such renewable energy capacity potential to meet domestic demand and/or regional trade is subject to each country's priorities, as well as specifics of sector development context and readiness.

Table 21. Annual Average Growth Rate of Installed Capacity by Technology, 2018–35

	Case 0 (%)	Case 1 (%)	Case 2 (%)	Case 3 (%)	Case 4 (%)	Case 5 (%)	Case 6 (%)
CC	7.7	7.7	7.2	6.9	7.4	7.1	6.1
CSP	8.9	5.8	9.0	5.8	40.1	36.1	5.9
GT	0.0	-0.6	-0.1	-0.8	-0.6	-1.1	-0.9
Hydro	-0.6	-0.6	-0.6	-0.6	0.5	0.5	-0.6
DG	-6.6	-6.5	-6.6	-6.7	-6.6	-6.7	-6.8
PV	26.4	26.1	26.1	26.2	25.6	25.7	25.1
ST	-2.2	-2.3	-2.2	-2.3	-2.3	-2.3	-2.3
Wind	14.2	17.3	19.3	19.8	20.6	20.7	17.3
Nuclear	9.9	9.4	21.0	22.0	22.1	24.1	17.4
ISCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	12.5	12.4	12.5	12.5	11.8	12.0	12.4
Total	4.9	4.8	5.0	4.9	6.4	6.0	4.0
RES	20.3	20.9	21.7	21.9	28.1	26.3	20.3

Source: World Bank staff based on EPM output.
Note: CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; GT = gas turbine; Hydro = hydroelectricity; ISCC = integrated solar combined cycle; PV = photovoltaic; RES = renewable energy sources; ST = steam turbine.

Figure 22. Renewable Energy in Total Energy Generated



Source: World Bank staff based on EPM output.
Note: CSP = concentrating solar power; Hydro = hydroelectricity; PV = photovoltaic; RES = renewable energy sources; TWh = terawatt-hour.

5), both renewable and nuclear generation significantly increase their participation in the energy mix in order to comply with the policy mandate. After adopting energy efficiency and demand response measures and enabling electricity trade, total energy generation decreases (Case 6 vs Case 2) due to overall regional electricity demand reduction.

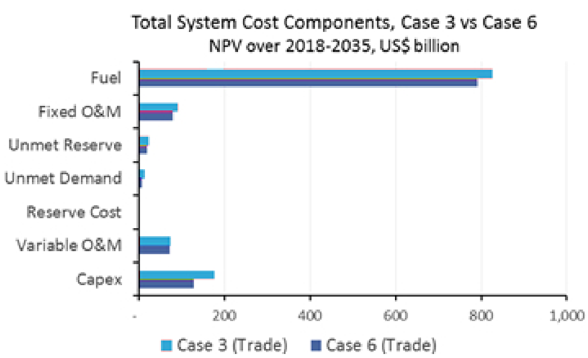
7.8. IMPACT OF ENERGY EFFICIENCY AND DEMAND RESPONSE ON THE BENEFITS FROM TRADE

As energy efficiency and demand response programs are becoming increasingly relevant in the Pan-Arab region, this section assesses the impact of decreasing energy demand projections on the benefits from trade in the region.

Specifically, this run of the model compares Case 6 with Case 3 in order to determine the impact of changes in electricity demand on total systems costs.

Figure 23 shows the results of the comparison. While Case 3 has a total system cost of US$1,211 billion, this decreases by US$107 billion, or 9 percent, with the consideration of demand-side measures in Case 6. The capital expenditures and other costs components are reduced as

Figure 23. Total System Costs, Case 3 vs. Case 6

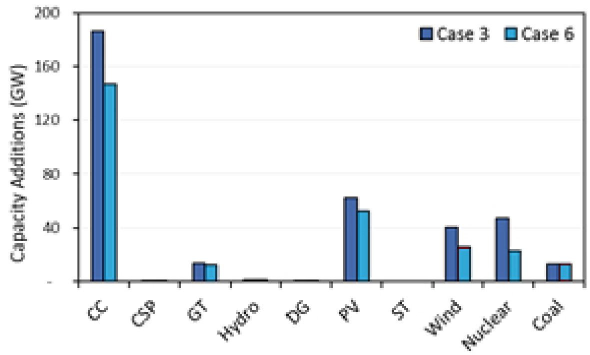


Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; NPV = net present value; O&M = operation and maintenance.

decreasing demand growth requires fewer capacity additions.

Total cumulative capacity additions in Case 3 add up to 364 GW; this decreases by 90 GW, or 25 percent, under Case 6 (total of 274 GW). Figure 24 presents the changes, by technology, in cumulative capacity additions by 2035. It is observed that, when comparing Case 6 to Case 3, practically all technologies experience reductions in their deployment, most notably combined cycle (39 GW reduction or 21 percent), solar PV (10 GW reduction or 16 percent), and wind (15 GW reduction or 38 percent).

Figure 24. Cumulative Capacity Addition by 2035, in GW



Source: World Bank staff based on EPM output.
Note: CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; GT = gas turbine; GW = gigawatt; Hydro = hydroelectricity; PV = photovoltaic; ST = steam turbine.

7.9. SUMMARY OF POTENTIAL TRADE BENEFITS

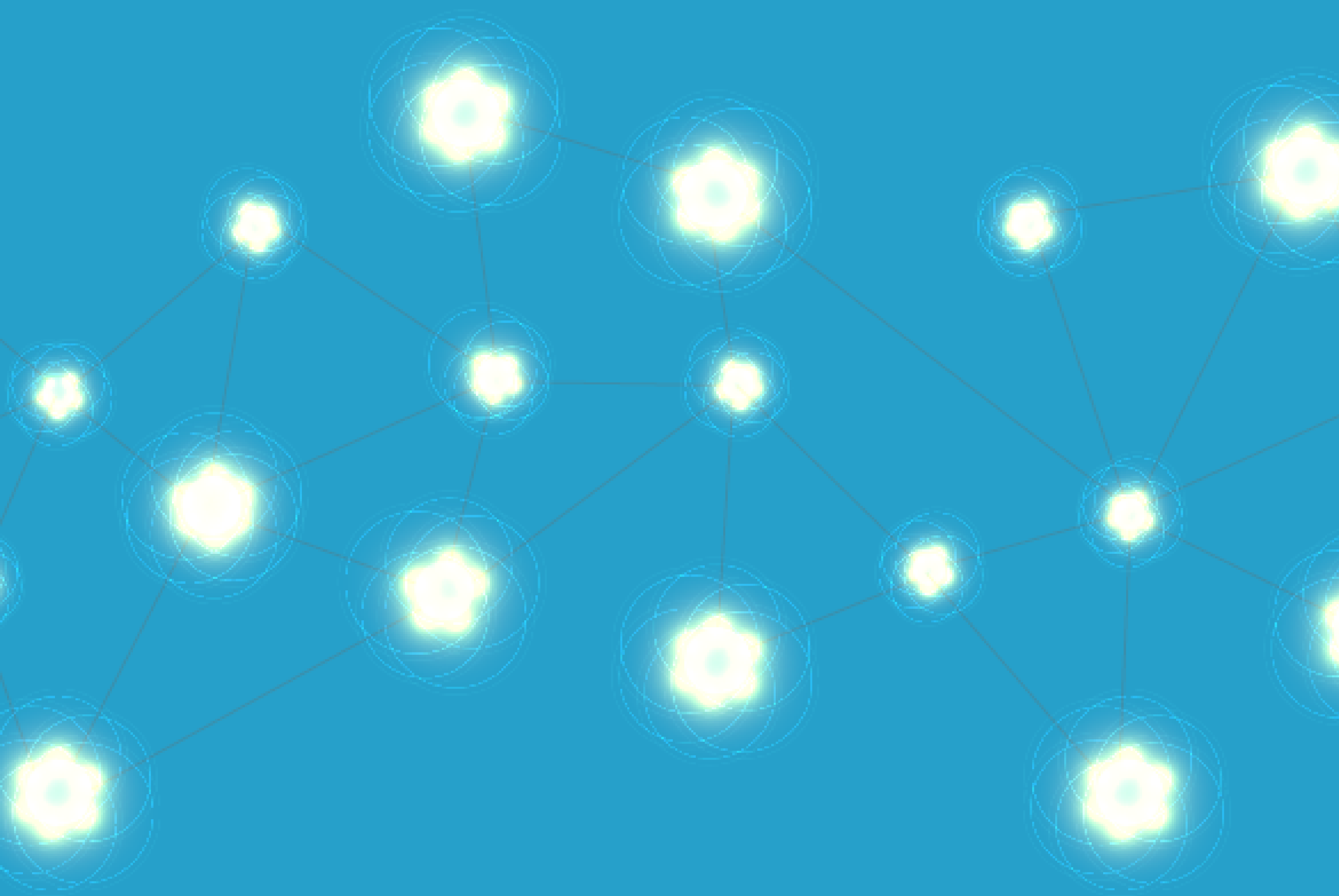
This chapter provided insights into how electricity trade will impact important areas of the region's power systems using the EPM, including total capacity and investment, total system costs, cost of electricity, the benefits of bilateral trade, carbon emissions, and transmission line utilization rates. Table 22 presents a summary of potential electricity trade benefits across the Pan-Arab Electricity Market (PAEM) in 2018–35 based on the comparison between the cases with trade allowed (Case 1, 3, 5 and 6) and the cases without trade (Case 0, 2 and 4).

Table 22. Summary of Potential Electricity Trade Benefits across PAEM for the Period 2018–35

Trade Case	Total System Cost Savings (US$ billion)	Shared Economic Benefits (US$ billion)	Commercial Value of Trade (US$ billion)	Average Transmission Utilization in 2035	Energy Security Improvement	Cost Savings for CO_2 Emissions Compliance US$ billion	Share of Renewable Capacity Installed	Investment in Renewable Technologies (US$ billion)
Case 1	$110	$109	$60	41%	38%	N/A	16%	$64
Case 3	$107	$32	$62	37%	38%	N/A	18%	$88
Case 5	$196	$150	$167	43%	53%	$86	28%	$305
Case 6	$213	$25	$60	37%	63%	N/A	17%	$68

Source: World Bank EPM calculations.

8 TRANSMISSION INVESTMENT ANALYSIS



In addition to the assessment of potential economic benefits of electricity trade, this report seeks to develop an understanding of the relative merits of various transmission interconnections between national power systems.[24] Some of them have been previously discussed and debated in other studies. However, they need to be reassessed in light of the substantial changes to the countries' demand-supply situation, the growing role of renewable energy in the Pan-Arab region, and the recent developments in establishing the Pan-Arab Electricity Market (PAEM) with increased interest to advance electricity trade by countries with surplus generation capacity.

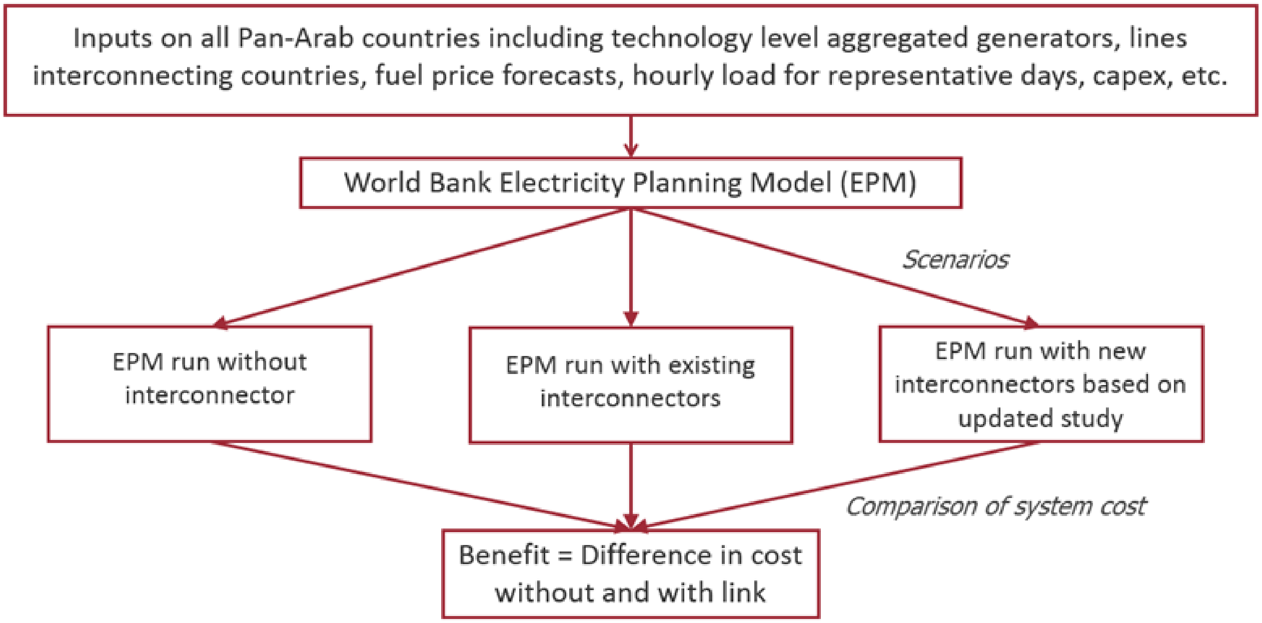
The aim of this chapter is to present an economic planning framework for cross-border interconnections in the region and apply it to existing and proposed interconnectors to assess potential transmission investment opportunities. It provides a preliminary assessment of investment cost estimates that should serve as a baseline for a framework to prioritize the cross-border interconnections proposed in this study to realize the commercial electricity trade benefits in the PAEM.

8.1. EVALUATING THE BENEFITS OF INTERCONNECTORS

Using the formulation of the electricity planning model described in chapter 6, this transmission investment analysis assesses the benefit of existing and proposed cross-border interconnections in the Pan-Arab region by comparing the changes in total cost of the system and interconnection utilization using the following modified scenarios:

- **Business as Usual (BAU)**: Under this scenario, natural gas is priced at international levels but no electricity is traded through cross-border lines, that is, electricity generation in each country is used to supply demand in that country (same as Case 2, see section 5.2).
- **Existing Interconnections**: Building on the BAU, under this scenario, cross-border electricity trade is enabled only for existing interconnections throughout the entire planning horizon.

Figure 25. Analytical Framework Used to Assess the Benefit of Cross-Border Interconnections in the Pan-Arab Region



Source: World Bank staff.
Note: CAPEX = capital expenditure.

[24] Although it is not in the scope of this study, it is important to highlight that a more detailed estimation of transmission interconnections exchanges and costs will require engaging in detailed load flow studies for each identified interconnection.

- **Proposed Interconnections**: Building on the existing interconnection scenario, under this scenario, cross-border electricity trade is enabled for existing and proposed new and reinforced interconnections, commissioned at different periods of the planning horizon (same as Case 3, see section 5.2).

Figure 25 summarizes the analytical framework used to assess the benefit of proposed new or reinforced cross-border interconnections in the Pan-Arab region.

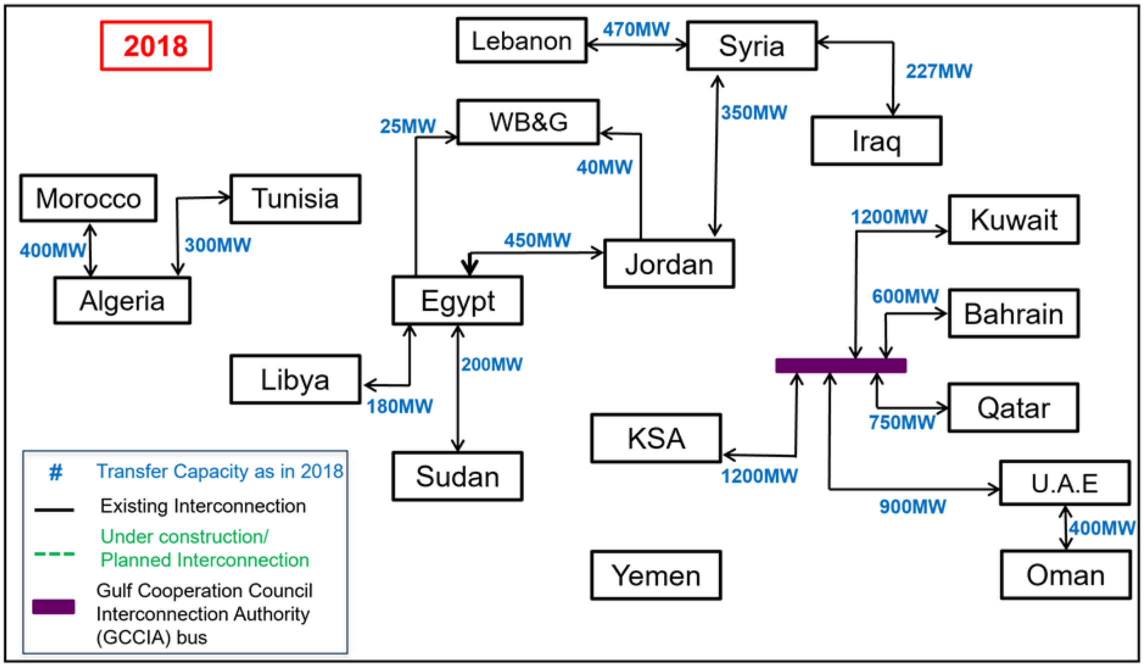
In this chapter, the assessment of potential economic benefits from electricity trade will mainly focus on the following categories:

- **Deferred capacity**: Better utilization of capacity resources across the zones in the region, which can contribute to a decrease in the total capacity needed to meet demand. To assess this benefit, yearly capital costs for each scenario with interconnectors are compared with the capital costs of the BAU scenario.
- **Fuel savings**: Access to lower fuel cost generation from other zones within the region. To assess this benefit, yearly fuel costs for each scenario with interconnectors are compared with those of the BAU scenario.
- **Greater reliability**: Greater ability to meet demand and reserves, which can in turn reduce the amount of unserved energy. To assess this benefit, yearly unmet demand (damage/economic loss because of unmet demand) and unmet reserve (penalty for unmet spinning reserve requirements) costs for each scenario with interconnectors are compared with those of the BAU scenario.

EXISTING CROSS-BORDER INTERCONNECTIONS IN THE PAN-ARAB REGION

Based on interconnection data collected from annual reports from electricity and transmission companies in the region and other regional studies, figure 26 presents the transmission lines that are considered to model the "existing interconnections" scenario. It is important to notice that the three subregions are not currently interconnected, which makes it a priority to focus on identifying critical interconnectors that will lead to a true Pan-Arab regional electricity market. For instance, it is critical to develop the interconnections

Figure 26. Regional Network with Existing Cross-Border Interconnections



Source: Based on data from Table 12.
Note: The transfer capacities of the existing transmission lines represented in this figure are based on the limitations set by contracting arrangements between the interconnected countries. In some cases, the design capacities of currently installed cross-border lines are higher.

between Tunisia and Libya, between Egypt and Saudi Arabia (currently under construction), and between Saudi Arabia and Jordan or Iraq.

PROPOSED NEW AND REINFORCED CROSS-BORDER INTERCONNECTIONS IN THE PAN-ARAB REGION

Table 23 describes the details on location, transfer capacity, and commissioning year of the new and reinforced interconnections proposed in this study. Notice that critical interconnections have been proposed such as the lines Tunisia ⇆ Libya, Saudi Arabia⇆Egypt, Saudi Arabia⇆Jordan, and Saudi Arabia⇆Iraq.

Figure 27 illustrates how the regional network would look by 2035 based on the proposed investment projects. It shows an overlay of the existing interconnections (black arrows) with the proposed interconnections (green arrows) including their transfer limits, in MW, and commissioning year. However, as the various countries become increasingly intertwined, a complex situation will arise requiring extensive load flow and system stability studies to determine the impact of power exchanges on their various domestic networks. Some may require significant additional costs to evacuate power, relieve bottlenecks, and maintain system security.

8.2. KEY FINDINGS: UTILIZATION OF CROSS-BORDER INTERCONNECTORS AND BENEFIT ANALYSIS

The following subsections analyze the interconnections' utilization throughout the entire planning horizon of the study and assess economic benefits.

EXISTING REGIONAL INTERCONNECTIONS

Enabling trade based just on the utilization of the existing transmission interconnections:

- Decreases total system costs by US$71 billion (compared with the case without trade, Case 2)
- Increases the annual average utilization[26] from 5–7 percent in 2018 to 36 percent in 2035
- Results in shared economic benefits of US$13 billion
- Exhibits an estimated commercial value of trade of US$23 billion
- Improves energy security by 23 percent
- Increases the share of renewable technologies in the energy mix to 17.6% by 2035
- Requires an investment of US$86.5 billion in renewable technologies.

Figure 28 illustrates the interconnectors, and the direction, that are used more than 50 percent by 2035 (in orange). It also indicates that Algeria, Saudi Arabia, Jordan, and Libya are electricity exporters while Tunisia, Lebanon, Kuwait, and Bahrain are electricity importers.

Table 24 presents the potential benefits, for the period 2018–35, from engaging in regional electricity trade by increasing the utilization of existing cross-border interconnectors. Total economic benefits amount to US$71 billion derived mainly from fuel savings and system reliability improvements. This is a remarkable finding considering the fact that $71 billion in costs savings can effectively be achieved without any hard investment in new physical interconnection. There is of course a need to improve coordination and related control facilities, but the cost of such softer measures is likely to be a small fraction of the savings.

[26] Annual average interconnection utilization refers to the unitless ratio calculated by dividing the yearly electricity flowing over a transmission line by the maximum possible yearly electricity flow.

Table 23. Reinforced and Proposed New Interconnections[25]

	Reinforced Interconnections	Increased Capacity (MW)	Total Capacity (MW)	Commissioning Year
1	Algeria (Ghazaouet/Tlemcen) ⇆ Morocco (Oujda)	600	1,000	2025
2	Egypt (High Dam) ⇆ Sudan (Merow)	1,000	1,200	2025
3	Egypt (El Arish) ⇆ Gaza Strip	175	200	2025
4	Egypt (Towiba) ⇆ Jordan (Aqaba)	650	1,100	2025
5	Jordan (Amman West) ⇆ West Bank	160	200	2025
6	Libya (Tobruk) ⇆ Egypt (Saloum ⇆ Sidi Krir PP) Stage 1	370	550	2025
7	Libya (Tobruk) ⇆ Egypt (Saloum) Stage 2	450	1,000	2030
8	Jordan (Amman North) ⇆ Syria (Dir Ali) Stage 1	450	800	2025
9	Jordan (Amman North) ⇆ Syria (Dir Ali) Stage 2	200	1,000	2030
10	Lebanon (Ksara) ⇆ Syria (Dimas)	730	1,200	2024
11	Saudi Arabia ⇆ GCCIA Interconnection System	600	1,800	2025
12	Kuwait ⇆ GCCIA Interconnection System	600	1,800	2025
13	Qatar ⇆ GCCIA Interconnection System	1,050	1,800	2025
14	UAE ⇆ GCCIA Interconnection System	900	1,800	2025
15	Bahrain ⇆ GCCIA Interconnectoin System	600	1,200	2025
	Proposed New Interconnections	**Total Capacity (MW)**		**Commissioning Year**
16	Saudi Arabia (Medinah) ⇆ Egypt (Badr)	3,000		2023
17	Saudi Arabia (Jazan) ⇆ Yemen (Saana/Tiaz/Aden)	500		2025
18	Tunisia (Bouchemma) ⇆ Libya (Melitia) Stage 1	500		2023
19	Tunisia (Bouchemma) ⇆ Libya (Melitia) Stage 2	500		2027
20	Saudi Arabia (Qurayyat) ⇆ Jordan (Qatranah)	1,000		2027
21	Saudi Arabia (Hail) ⇆ Iraq (Karbala)	1,000		2027
22	Jordan (Amman East) ⇆ Iraq (Qa'im) via Azraq NPS	500		2025
23	Saudi Arabia (Ras Abu Gamys) ⇆ Oman (Ibri IPP)	1,000		2027
24	Kuwait (Subiyah) ⇆ Iraq (Basra)	1,000		2027
25	Kuwait (Jahra) ⇆ Saudi Arabia (Qaisumah/Rafha)	1,000		2027

Source: Proposed by World Bank staff after consultations with countries representatives.
Note: MW = megawatt.

[25] Even if the commissioning year of one or more cross-border interconnection project are delayed, the projects proposed in this table are still relevant as a baseline for regional investments between the PAEM countries.

To further detail the economic benefits of trade, figure 29 illustrates the annual benefit over time, by cost category (left) and the changes in capacity additions (right) in years 2020, 2025, 2030, and 2035.

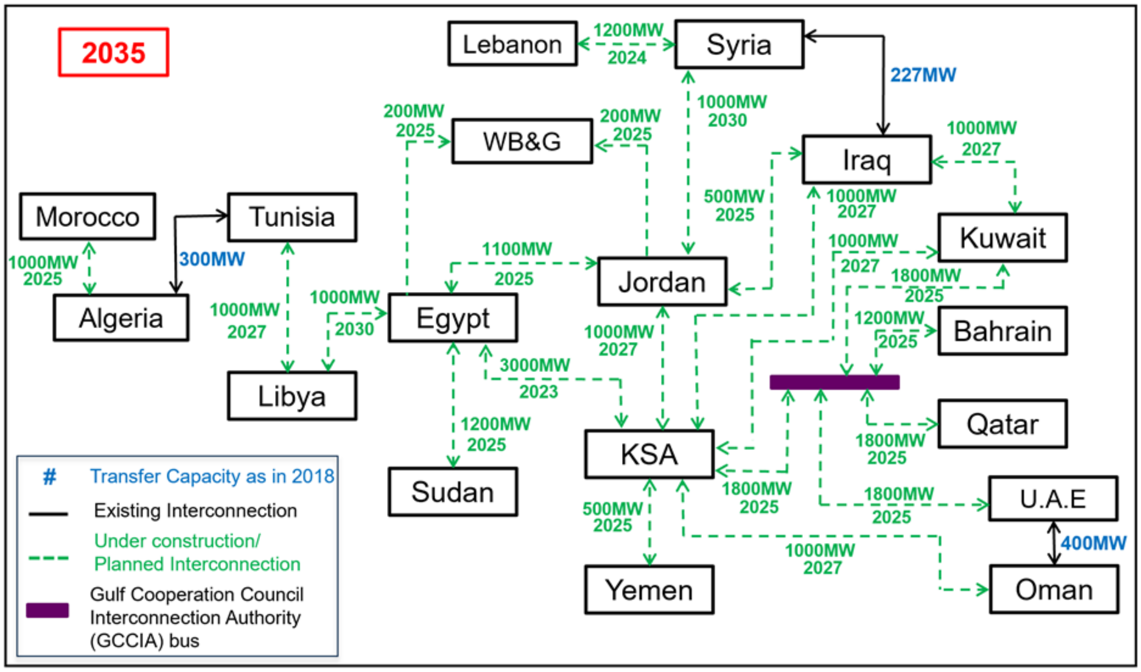
Table 25 presents the expected electricity flows for the existing cross-border interconnections and their respective utilization for the year 2035, organized from the highest interconnection utilization to the lowest. Some interconnections with lower utilization can exchange a higher amount of electricity than those with higher utilization. For instance, with an interconnection utilization of 31 percent, the line from the United Arab Emirates (UAE) to the Gulf Cooperation Council Interconnection Authority (GCCIA) registers an electricity volume of 2,409 gigawatt hours (GWh) in 2035. This is higher than the flow in the interconnector from Libya to Egypt, 1,555 GWh in 2035, which has a utilization of 99 percent.

PROPOSED AND REINFORCED INTERCONNECTORS

Accounting for existing, proposed, and reinforced interconnections to engage in regional electricity trade increases the annual average utilization from 5–7 percent in 2018 to 35 percent in 2035. There are 14 interconnectors that are consistently used, in the cases where electricity trade was enabled, more that 50 percent in 2035. Figure 30 illustrates the interconnectors, and their direction, that are used more than 50 percent by 2035 (in red). It indicates that Algeria, Egypt, Syria, and Saudi Arabia are electricity exporters while Iraq, Kuwait, Bahrain, Yemen, Sudan, Morocco, Lebanon, and Tunisia are electricity importers.

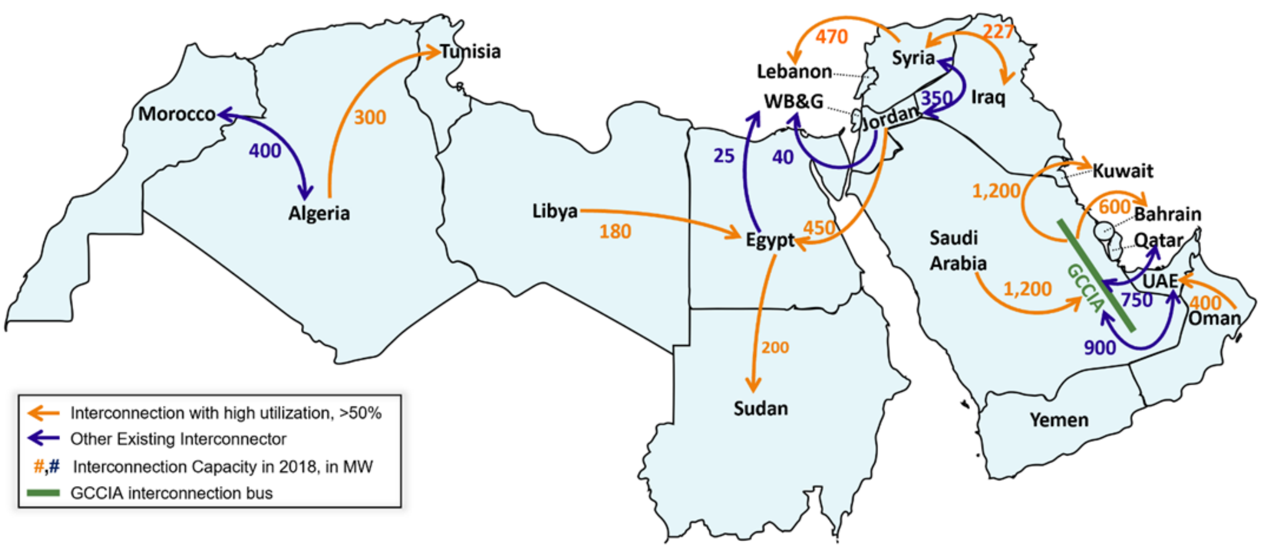
Table 26 presents the potential benefits, for the period 2018–35, from engaging in regional electricity trade by commissioning proposed

Figure 27. Regional Network with Proposed and Reinforced Cross-Border Interconnections



Source: Proposed by World Bank staff after consultations with countries representatives.
Note: KSA = Saudi Arabia; MW = megawatt; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Figure 28. Existing Cross-Border Interconnectors' Utilization in 2035



Source: World Bank staff based on EPM output.
Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.
GCCIA = Gulf Cooperation Council Interconnection Authority; MW = megawatt; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

and reinforced cross-border interconnectors in the Pan-Arab region. Allowing regional electricity trade will result in important economic benefits, potentially amounting to US$107 billion, derived mainly from savings on costs needed for maintaining capacity reserve and fuel savings. This means that investing in more regional interconnectors, compared to only increasing the utilization of existing cross-border interconnections, will lead to even more economic benefits. The incremental benefits of planned interconnections over and above that of the existing interconnection is $35 billion (= $107 billion minus $72 billion). The decreasing incremental benefits from the new interconnectors indicate that most

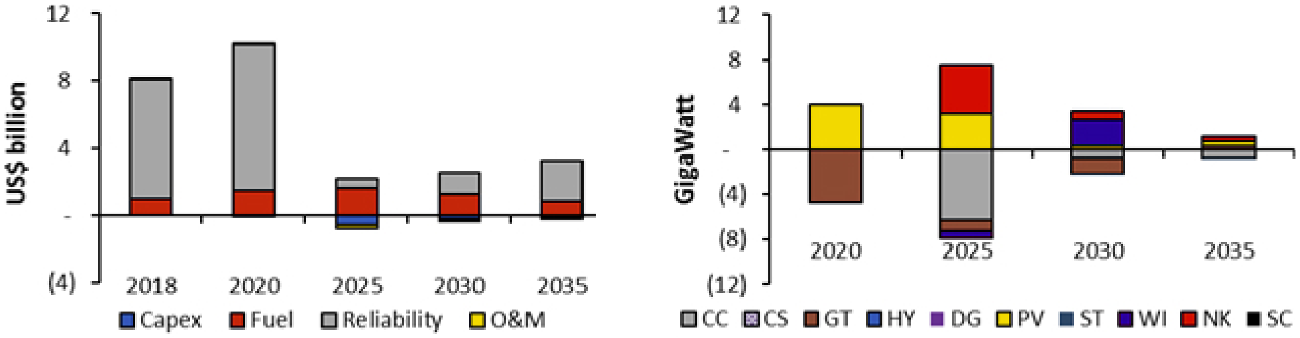
Table 24. Summary of Economic Benefits of Engaging in Regional Trade by Increased Utilization of Existing Cross-Border Interconnections

	Scenario	Total System Cost ($ million)	Fuel Cost[a] ($ million)	Capital Cost[b] ($ million)	Reliability[c] ($ million)	O&M Cost[d] ($ million)
Pan-Arab system	Without any cross-border interconnectors, BAU	1,317,531	850,346	180,307	120,605	166,274
	With increased utilization of existing cross-border interconnectors	1,246,055	831,426	181,558	65,751	167,320
	Benefits[e]	**71,476**	**18,920**	**-1,251**	**54,854**	**-1,047**

Source: World Bank staff based on EPM output.
Note: Total discounted cost of operating the regional power system in the period of 2018–35, assuming discount rate of 6 percent. (a) Total cost of fuel consumed in the period of 2018–35; (b) Total annualized cost of building new generation capacity in the period 2018–30, assuming a weighted average cost of capital (WACC) of 6 percent; (c) Includes the cost of unserved energy plus the cost of unserved reserves; (d) Includes fixed and variable operation and maintenance cost; and (e) Economic benefits are estimated as the difference between the discounted cost of the power system without using cross-border interconnectors minus the discounted cost of the system using existing cross-border interconnectors. BAU = business as usual.

Figure 29. Annual Economic Benefits of Engaging in Regional Electricity Trade

(Years 2020, 2025, 2030, and 2035: Left—Using Existing Interconnectors; Right—Changes in Capacity Additions)



Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; CC = combined cycle; CS = concentrating solar power; DG = diesel generator; GT = gas turbine; GW = gigawatt; HY = hydroelectricity; O&M = operation and maintenance; PV = photovoltaic; ST = steam turbine; WI = wind; NK = nuclear; SC = coal-fired steam turbine.

of the benefits have already been achieved by better utilization of existing interconnectors. As discussed later in more detail, this would typically entail some of the planned interconnections being loaded lightly, albeit these would also generate savings. It is uncertain whether the incremental benefit of $35 billion would cover the investments needed for all of the proposed interconnectors. To determine this, a major engineering study would be required to assess the costs. Nevertheless, a discounted $35 billion over 18 years (which represents typically between half and one-third of the life of a transmission asset) can support upward of 100 major interconnection projects, which far exceeds the number of projects that are considered as part of this study.

To further detail the economic benefits of trade, figure 31 illustrates the annual benefit over time, by system cost category (left) and the changes in capacity additions (right) in years 2020, 2025, 2030, and 2035. Changes in capacity additions show increased deployment of renewable and nuclear energy. They also show decreased deployment of fossil-fueled generation that would otherwise be deployed for capacity reserve, mainly combined cycle and gas turbine technologies.

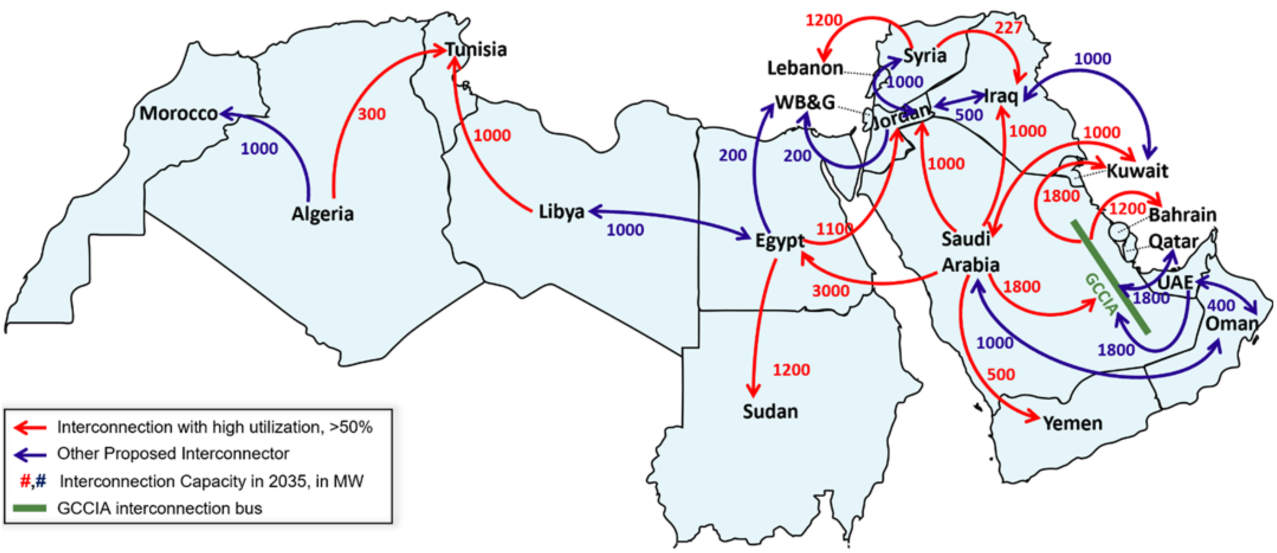
Table 27 presents the expected electricity flows for the existing and proposed cross-border interconnections and their respective utilization for the year 2035, organized from the highest interconnection utilization to the lowest. The first 18 interconnections represent potential transmission investments that will strengthen electricity trade in the region, amounting to a total of 130 terawatt-hours (TWh) of electricity traded in 2035.

Table 25. Expected Flows and Utilization for Existing Cross-Border Interconnections in 2035

From	To	Flow in 2035 (GWh)	Utilization in 2035 (%)	From	To	Flow in 2035 (GWh)	Utilization in 2035 (%)
Egypt	Sudan	1,749	100	Qatar	GCCIA	1,930	26
Libya	Egypt	1,555	99	GCCIA	UAE	1,798	21
Algeria	Tunisia	2,498	94	Jordan	WB&G	53	15
Syria	Lebanon	3,594	87	Syria	Jordan	431	14
Jordan	Egypt	3,329	85	GCCIA	Qatar	581	10
Saudi Arabia	GCCIA	8,686	81	GCCIA	Saudi Arabia	997	10
GCCIA	Kuwait	7,150	66	Egypt	WB&G	19	9
Oman	UAE	2,135	55	Jordan	Syria	248	8
Iraq	Syria	1,014	51	Bahrain	GCCIA	237	5
Syria	Iraq	958	48	Lebanon	Syria	89	2
GCCIA	Bahrain	2,556	47	Egypt	Jordan	81	2
Morocco	Algeria	1,204	34	UAE	Oman	41	1
UAE	GCCIA	2,409	31	Kuwait	GCCIA	87	1
Algeria	Morocco	1,039	29	Egypt	Libya	-	0

Source: World Bank staff based on EPM output.

Figure 30. Proposed Cross-Border Interconnectors' Utilization in 2035



Source: World Bank staff based on EPM output.
Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.
GCCIA = Gulf Cooperation Council Interconnection Authority; MW = megawatt; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

BENEFITS OF SELECTED INTERCONNECTORS

To illustrate how the analytical framework proposed in this section can be applied to the assessment of specific interconnectors, and based on the list of potential interconnection investments in the Pan-Arab region (table 23), this study has selected two sets of cross-border interconnections as follows: the first set, the Saudi Arabia–Iraq, Jordan-Iraq, and the Saudi Arabia–Jordan Interconnections; and the second set, consisting of the Algeria–Morocco, Algeria–Tunisia, Tunisia–Libya and Libya–Egypt interconnections.

Connecting GCC and Mashreq subregions: Table 28 presents the potential benefits for the first set of interconnectors, over the period 2018–35, from engaging in regional electricity trade by increasing the utilization of proposed cross-border interconnectors between Saudi Arabia–Iraq, Jordan–Iraq, and Saudi Arabia–Jordan. Total economic benefits amount to US$2.2 billion derived mainly from fuel cost savings and some system reliability improvement. This is a significant savings above

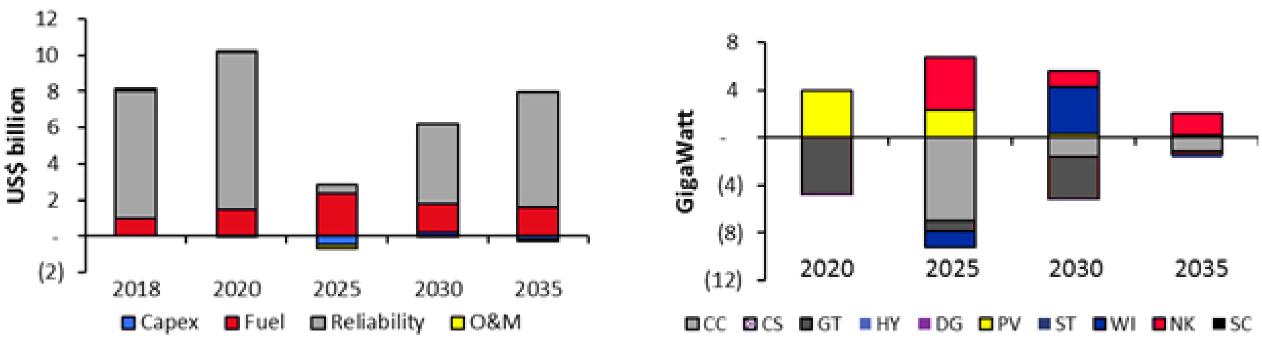
Table 26. Summary of Economic Benefits for the Pan-Arab Regional Trade by Commissioning Proposed Cross-Border Interconnections

	Scenario	Total System Cost ($ million)	Fuel Cost[a] ($ million)	Capital Cost[b] ($ million)	Reliability[c] ($ million)	O&M Cost[d] ($ million)
Pan-Arab system	**Without any** cross-border interconnectors, BAU	1,317,531	850,346	180,307	120,605	166,274
	With **proposed and reinforced** cross-border interconnectors	1,211,011	825,912	178,018	40,637	166,445
	Benefits[e]	**106,520**	**24,434**	**2,289**	**79,968**	**-171**
	With increased utilization of **existing** cross-border interconnectors	1,246,055	831,426	181,558	65,751	167,320
	With **proposed and reinforced** cross-border interconnectors	1,211,011	825,912	178,018	40,637	166,445
	Benefits[e]	**35,044**	**5,514**	**3,540**	**25,114**	**876**

Source: World Bank staff based on EPM output.
Note: Total discounted cost of operating the regional power system in the period of 2018–35, assuming discount rate of 6 percent. (a) Total cost of fuel consumed in the period of 2018–35; (b) Total annualized cost of building new generation capacity in the period 2018–30, assuming a weighted average cost of capital (WACC) of 6 percent; (c) Includes the cost of unserved energy plus the cost of unserved reserves; (d) Includes fixed and variable operation and maintenance cost; and (e) Economic benefits are estimated as the difference between the discounted cost of the power system without using cross-border interconnectors minus the discounted cost of the system using all (existing and planned) cross-border interconnectors. BAU = business as usual.

Figure 31. Annual Economic Benefits of Engaging in Regional Electricity Trade Using Proposed and Existing Interconnectors

(Years 2020, 2025, 2030, and 2035: Left—Using Existing Interconnectors; Right—Changes in Capacity Additions)



Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; CC = combined cycle; CS = concentrating solar power; DG = diesel generator; GT = gas turbine; GW = gigawatt; HY = hydroelectricity; O&M = operation and maintenance; PV = photovoltaic; ST = steam turbine; WI = wind; NK = nuclear; SC = coal-fired steam turbine..

the cost of these interconnectors (see table 32).

To further detail the economic benefits of trade, figure 32 illustrates the annual benefit over time, by cost category (left) and the changes in capacity additions (right) in years 2020, 2025, 2030, and 2035 for the selected set of interconnections.

Table 29 presents the expected electricity flows for the proposed cross-border interconnections and their respective utilization for the year 2035, organized from the highest interconnection utilization to the lowest.

Connecting the Mashreq and the Maghreb: The benefits of the second set of interconnectors are also assessed. Table 30 presents the potential benefits, for the period 2018–35, from engaging in regional electricity trade by commissioning the proposed cross-border interconnectors. The economic benefits are calculated at US$8 billion derived mainly from system reliability improvements and fuel cost savings.

To further detail the economic benefits from the second set of selected interconnectors, figure 33 illustrates the annual benefit over time, by

Table 27. Expected Flows and Utilization of Proposed and Existing Cross-Border Interconnections in 2035

From	To	Flow in 2035 (GWh)	Utilization in 2035 (%)	From	To	Flow in 2035 (GWh)	Utilization in 2035 (%)
Libya	Egypt	8,760	100	UAE	GCCIA	4,993	32
Libya	Tunisia	8,647	99	Oman	Saudi Arabia	2,759	32
Egypt	Sudan	9,714	92	Saudi Arabia	Oman	2,308	26
Saudi Arabia	Kuwait	7,959	91	Qatar	GCCIA	3,630	23
Saudi Arabia	Yemen	3,983	91	Kuwait	Iraq	1,979	23
Algeria	Tunisia	2,377	91	Morocco	Algeria	1,914	22
Saudi Arabia	GCCIA	13,634	87	Jordan	WB&G	276	16
Syria	Lebanon	9,029	86	UAE	Oman	480	14
Saudi Arabia	Egypt	20,792	79	GCCIA	Qatar	1,954	12
GCCIA	Kuwait	12,052	76	Egypt	Saudi Arabia	2,779	11
Saudi Arabia	Jordan	6,411	73	Iraq	Saudi Arabia	929	11
Jordan	Egypt	5,952	62	Egypt	WB&G	184	11
Iraq	Kuwait	5,924	60	Jordan	Saudi Arabia	856	10
GCCIA	Bahrain	5,959	57	Egypt	Jordan	917	10
Oman	UAE	1,944	56	GCCIA	Saudi Arabia	1,436	9
Iraq	Jordan	2,306	53	GCCIA	UAE	872	6
Iraq	Syria	1,008	51	Bahrain	GCCIA	467	4
Saudi Arabia	Iraq	4,432	51	Jordan	Syria	389	4
Syria	Iraq	942	47	Kuwait	Saudi Arabia	373	4
Syria	Jordan	3,390	45	Lebanon	Syria	87	1
Jordan	Iraq	1,960	45	Yemen	Saudi Arabia	21	1
Algeria	Morocco	3,078	35	Sudan	Egypt	22	0

Source: World Bank staff based on EPM output.
Note: GCCIA = Gulf Cooperation Council Interconnection Authority; GWh = gigawatt-hour; UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 28. Summary of Economic Benefits of Regional Trade between GCC and Mashreq by Commissioning Proposed Cross-Border Interconnectors between Jordan, Saudi Arabia, and Iraq

Scenario	Total System Cost ($ million)	Fuel Cost[a] ($ million)	Capital Cost[b] ($ million)	Reliability[c] ($ million)	O&M Cost[d] ($ million)
Iraq, Jordan and Saudi Arabia **without** interconnectors	542,191	351,940	101,158	9,754	79,339
Iraq, Jordan, and Saudi Arabia **with proposed** interconnectors	540,007	341,591	107,673	9,348	81,395
Benefits[e]	**2,184**	**10,350**	**-6,515**	**406**	**-2,057**

Source: World Bank staff based on EPM output.
Note: Total discounted cost of operating the regional power system in the period of 2018–35, assuming discount rate of 6 percent. (a) Total cost of fuel consumed in the period of 2018–35; (b) Total annualized cost of building new generation capacity in the period 2018–30, assuming a weighted average cost of capital (WACC) of 6 percent; (c) Includes the cost of unserved energy plus the cost of unserved reserves; (d) Includes fixed and variable operation and maintenance (O&M) cost; (e) Economic benefits are estimated as the difference between the discounted cost of the power system without using cross-border interconnectors minus the discounted cost of the system using selected, planned cross-border interconnectors.

cost category (left) and the changes in capacity additions (right) in years 2020, 2025, 2030, and 2035. Annual economic benefits result, mainly, from fuel savings and increased reliability in the systems of these five countries as renewable energy technologies, solar PV and wind, increase their participation in the energy mix.

Table 31 presents the expected electricity flow for the proposed cross-border interconnection among Morocco, Algeria, Tunisia, Libya, Egypt and their respective utilization for the year 2035. The interconnections from Libya to Tunisia and from Libya to Egypt have the highest utilization, 99 percent and 98 percent, respectively. However, the interconnections between Algeria and Morocco, in both directions, exchange the largest amount of electricity among all the projects, a total of 17 TWh.

SENSITIVITY TO ENERGY-SECTOR-RELATED POLICIES

Employing the energy policies described for Cases 1 and 5 (see section 5.2), the study can also infer the sensitivity of interconnection utilization to changes in natural gas prices and environmental policies. Figures 34, 35, 36, and

Table 29. Expected Flows and Utilization of Proposed Cross-Border Interconnections between GCC and Mashreq

(through Jordan, Saudi Arabia, and Iraq, in 2035)

From	To	Flow in 2035 (GWh)	Utilization in 2035 (%)
Saudi Arabia	Jordan	451	49
Saudi Arabia	Iraq	907	47
Jordan	Iraq	1,969	45
Jordan	Saudi Arabia	927	11
Iraq	Saudi Arabia	4,139	10
Iraq	Jordan	4,251	10

Source: World Bank staff based on EPM output.
Note: GWh = gigawatt-hour; WB&G = West Bank and Gaza.

37 display the annual utilization rate for each cross-border transmission line considered in this study, for the year 2035, engaging in electricity trade under current natural gas prices (Case 1), international gas prices (Case 3), CO_2 emissions limits (Case 5), and energy efficiency and demand response adoption (Case 6), respectively. The vertical axis represents the origin of the transmission line and the horizontal axis represents the line's destination. The numbers in the cells represent the utilization of the line (as a fraction from 0 to 1) in 2035. If it is marked in red then the utilization is >90 percent and at or close to full capacity, possibly even overloaded. Light red (80–90 percent), orange (60–70 percent), yellow (30–60 percent), light green (10–30 percent), and dark green (0–10 percent) mark the other levels of utilization.

Table 31. Expected Flows and Utilization of Proposed Cross-Border Interconnections between Mashreq and Maghreb (2035)

(through Reinforced and Proposed Interconnectors among Morocco, Algeria, Tunisia, Libya, and Egypt)

From	To	Flow in 2035 (GWh)	Utilization in 2035 (%)
Libya	Tunisia	2,446	99
Libya	Egypt	2,366	98
Algeria	Tunisia	-	90
Algeria	Morocco	8,573	28
Morocco	Algeria	8,643	18
Egypt	Libya	1,549	0
Tunisia	Algeria	-	0
Tunisia	Libya	-	0

Source: World Bank staff based on EPM output.
Note: GWh = gigawatt-hour; WB&G = West Bank and Gaza.

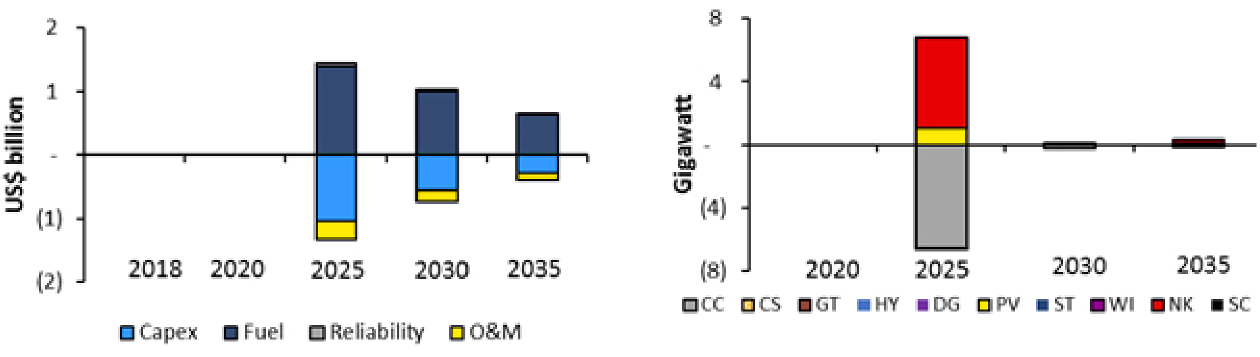
In figure 35, the countries with the highest level of exports on their lines are Algeria, Saudi Arabia, Qatar, and Syria. The countries with the highest level of imports on their lines are Iraq, West Bank and Gaza, Kuwait, Tunisia, and Morocco. The lines with utilization >95 percent are:

Algeria → Tunisia, Egypt → Sudan, Iraq → Jordan, Libya → Egypt, Libya → Tunisia, Qatar → GCCIA, Saudi Arabia → Yemen, Saudi Arabia → Kuwait, Saudi Arabia → Egypt, and GCCIA → Kuwait.

Countries with large reserves of gas have declining rates of transmission line utilization over time under international gas prices (Case 3, figure 35). While there are significant investments in gas generation under this case, there is not enough of a generation price differential between countries

Figure 32. Annual Economic Benefits of Engaging in Regional Electricity Trade Using Proposed Interconnectors Between GCC and Mashreq

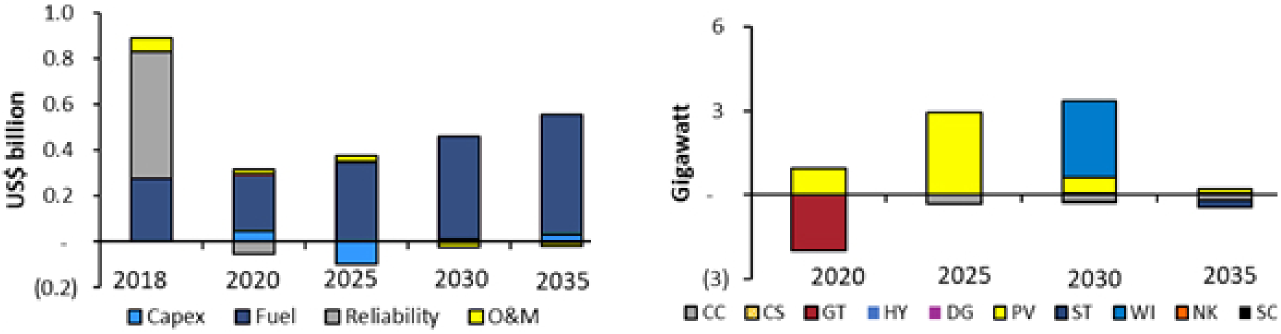
(Years 2020, 2025, 2030, and 2035: Left—between GCC and Mashreq through Jordan, Saudi Arabia and Iraq; Right—Changes in Capacity Additions)



Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; CC = combined cycle; CS = concentrating solar power; DG = diesel generator; GT = gas turbine; GW = gigawatt; HY = hydroelectricity; O&M = operation and maintenance; PV = photovoltaic; ST = steam turbine; WI = wind; NK = nuclear; SC = coal-fired steam turbine.

Figure 33. Annual Economic Benefits of Engaging in Regional Electricity Trade between Mashreq and Maghreb

(Years 2020, 2025, 2030, and 2035: Left—Benefits through Reinforced and Proposed Interconnectors among Morocco, Algeria, Tunisia, Libya, and Egypt; Right—Changes in Capacity Additions)



Source: World Bank staff based on EPM output.
Note: CAPEX = capital expenditure; CC = combined cycle; CS = concentrating solar power; DG = diesel generator; GT = gas turbine; GW = gigawatt; HY = hydroelectricity; O&M = operation and maintenance; PV = photovoltaic; ST = steam turbine; WI = wind; NK = nuclear; SC = coal-fired steam turbine..

Table 30. Summary of Economic Benefits of Regional Trade between Mashreq and Maghreb by Commissioning Reinforced and Proposed Cross-Border Interconnectors among Morocco, Algeria, Tunisia, Libya, and Egypt

Scenario	Total System Cost ($ million)	Fuel Cost[a] ($ million)	Capital Cost[b] ($ million)	Reliability[c] ($ million)	O&M Cost[d] ($ million)
Morocco, Algeria, Tunisia, Libya, Egypt **without** interconnectors	308,270	228,926	28,637	4,256	46,452
Morocco, Algeria, Tunisia, Libya, Egypt with **Proposed** interconnectors	300,260	224,304	27,705	1,882	46,368
Benefits[e]	**8,010**	**4,622**	**932**	**2,373**	**84**

Source: World Bank staff based on EPM output.
Note: Total discounted cost of operating the regional power system in the period of 2018–35, assuming discount rate of 6 percent. (a) Total cost of fuel consumed in the period of 2018–35; (b) Total annualized cost of building new generation capacity in the period 2018–30, assuming a weighted average cost of capital (WACC) of 6 percent; (c) Includes the cost of unserved energy plus the cost of unserved reserves; (d) Includes fixed and variable operation and maintenance (O&M) cost; (e) Economic benefits are estimated as the difference between the discounted cost of the power system without using cross-border interconnectors minus the discounted cost of the system using selected, planned cross-border interconnectors.

for trade relative to the case with current gas prices (Case 1). However, international gas prices will not reduce utilization rates, as the system will deploy more renewable and nuclear generation technologies and maintain overall interconnection utilization rates. The average utilization rate for current gas prices (Case 1) is estimated at 40%, international gas prices (Case 3) at 36%, and 45% with CO_2 emissions limits (Case 5, figure 36).

Although the overall annual average utilization is not significantly affected by energy policies, the utilization of some interconnectors changes in terms of magnitude and direction. For instance, in Case 1 Qatar is an electricity exporter, as the country prices its gas low and enjoys ample natural gas reserves. However, as the gas price increases, Qatar becomes neither an exporter nor an importer of electricity; and, when CO_2 emission limits are introduced, Qatar becomes an electricity importer, as indicated in figure 36.

When demand-side measures are applied, the overall average interconnection utilization rate remains unchanged—36 percent, as in Case 3. However, as seen in figure 37, unlike the carbon caps policy (Case 5), there are not significant changes in terms of direction of electricity trade flows. For instance, in the GCCIA Kuwait interconnection, the latter remains a net importer. However, significant changes in terms of the magnitude of average utilization can be found. For example, the average utilization of the interconnection from Saudi Arabia to Egypt decreases from 79 percent in Case 3 to 22 percent in Case 6, affecting the prioritization of these interconnectors and indicating that further feasibility studies should be conducted.

Figure 34. Cross-Border Interconnection Utilization Rates in 2035: Trading under Current Gas Prices (Case 1)

From-to	ALG	BAH	EGY	IRQ	JOR	KUW	LEB	LIB	MOR	OMA	WBG	QAT	KSA	SUD	SYR	TUN	UAE	YEM	GCCIA
ALG									0.59							0.96			
BAH																			0.011
EGY					0.07						0.114		0.03	0.92					
IRQ					0.98	0.77							0.09		0.62				
JOR			0.8	0							0.348		0.02		0.1				
KUW				0.2									0.01						
LEB															0.01				
LIB			1													0.97			
MOR	0.08																		
OMA													0.27				0.03		
WBG																			
QAT																			0.999
KSA			0.96	0.7	0.85	0.96				0.69								0.98	0.669
SUD			0																
SYR				0	0.33		0.84												
TUN																			
UAE										0.29									0.309
YEM													0						
GCCIA		0.89				0.99							0.14				0.23		

Interconnection Utilization

Low High

Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; GCCIA = Gulf Cooperation Council Interconnection Authority; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 35. Cross-Border Interconnection Utilization Rates (2035): Trading under International Gas Prices (Case 3)

From-to	ALG	BAH	EGY	IRQ	JOR	KUW	LEB	LIB	MOR	OMA	WBG	QAT	KSA	SUD	SYR	TUN	UAE	YEM	GCCIA
ALG									0.35							0.91			
BAH																			0.044
EGY					0.1						0.11		0.11	0.92					
IRQ					0.53	0.6							0.11		0.51				
JOR			0.62	0.4							0.16		0.1		0.04				
KUW				0.2									0.04						
LEB															0.01				
LIB			1													0.99			
MOR	0.22																		
OMA													0.32				0.56		
WBG																			
QAT																			0.23
KSA			0.79	0.5	0.73	0.91				0.26								0.91	0.865
SUD			0																
SYR				0.5	0.45		0.86												
TUN																			
UAE										0.14									0.317
YEM													0.01						
GCCIA		0.57				0.76						0.12	0.09				0.06		

Interconnection Utilization

Low High

Source: World Bank staff based on EPM output.
Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; GCCIA = Gulf Cooperation Council Interconnection Authority; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 36. Cross-Border Interconnection Utilization Rates in 2035, when Trading under International Gas Prices and Applying CO2 Emission Limits (Case 5)

From-to	ALG	BAH	EGY	IRQ	JOR	KUW	LEB	LIB	MOR	OMA	WBG	QAT	KSA	SUD	SYR	TUN	UAE	YEM	GCCIA
ALG									0.1							0.97			
BAH																			
EGY								0.98			0.009			1					
IRQ																			
JOR			0.99	1							0.836		0.07		1				
KUW				1															0.00
LEB															0.02				
LIB			0													0.13			
MOR	0.45																		
OMA																	0.01		
WBG																			
QAT																			0.00
KSA			1	1	0.77	1				1								0.9	1.00
SUD																			
SYR				1			0.14												
TUN	0.02							0.12											
UAE										0.98									0.98
YEM													0.01						
GCCIA		0.58				0.98						0.56					0.01		

Interconnection Utilization

Low High

Source: World Bank staff based on EPM output.

Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; GCCIA = Gulf Cooperation Council Interconnection Authority; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 37. Cross-Border Interconnection Utilization Rates in 2035, when Trading under International Gas Prices and Applying Demand-Side Measures (Case 6)

From-to	ALG	BAH	EGY	IRQ	JOR	KUW	LEB	LIB	MOR	OMA	WBG	QAT	KSA	SUD	SYR	TUN	UAE	YEM	GCCIA
ALG									0.37							0.24			
BAH																			0.082
EGY					0.9			0.55			0.553		0.32	0.74					
IRQ					0.05	0.1							0.08		0.07				
JOR				0.9							0.055		0.18		0.21				
KUW				0.7									0.04						
LEB															0.01				
LIB			0.32													0.96			
MOR	0.26																		
OMA													0.25				0.33		
WBG																			
QAT																			0.602
KSA			0.22	0.9	0.68	0.9				0.32								0.7	0.588
SUD			0																
SYR				0.9	0.28		0.84												
TUN	0.26																		
UAE										0.23									0.282
YEM													0.03						
GCCIA		0.42				0.94							0.14				0.14		

Interconnection Utilization

Low High

Source: World Bank staff based on EPM output.

Note: ALG = Algeria; BAH = Bahrain; EGY = Egypt; GCCIA = Gulf Cooperation Council Interconnection Authority; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; OMA = Oman; WBG = West Bank and Gaza; QAT = Qatar; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

8.3. TRANSMISSION INTERCONNECTION INVESTMENT COSTS

Ultimately, the analysis of economic benefits from selected interconnection projects discussed above must be complemented by suitable transmission cost information, with due consideration of the technological options available. Unit cost estimates such as the transmission line costs per kilometer (km) and the unit costs of the required terminal or transformer substation equipment are available from various consultants active in the MENA region (see appendix G for details).

Table 32. Summary Transmission Technical Characteristics and Estimated Project Costs (EPC), $ Million

	Reinforced Interconnections	Technical Characteristics	Distance (km)	EPC US$M
1	Algeria (Ghazaouet/Tlemcen) ⇆ Morocco (Oujda)[1]	Existing HVAC OHTL 2*220kV and 2*400kV	N/A	$0.0
2	Egypt (High Dam) ⇆ Sudan (Merow)	HVAC OHTL 500 kV plus 4 bays	730	$374.9
3	Egypt (El Arish) ⇆ Gaza Strip[2]	OHTL 200kV rated 950MVA	45	$250.0
4	Egypt (Taba) ⇆ Jordan (Aqaba)	Second line 400kV, HVAC Submarine Cable	13	$150.0
5	Jordan (Amman West) ⇆ West Bank	(JDECO-4) HVAC OHTL 400 kV	40	$39.4
6	Libya (Tobruk) ⇆ Egypt (Saloum-Sidi Krir PP) Stage 1	500kV line from Sidi Krir to Saloum HVDC BtB, 400KV to Tobruk	616	$493.4
7	Libya (Tobruk) ⇆ Egypt (Saloum) Stage 2	HVDC BtB/Trafos Upgraded to 1000MW	616	$196.0
8 9	Jordan (Amman North) ⇆ Syria (Dir Ali) Stage 1 Jordan (Amman North) ⇆ Syria (Dir Ali) Stage 2	HVAC OHTL 400 kV plus two bays each end	105	$53.4
10	Lebanon (Ksara) ⇆ Syria (Dimas)	HVAC OHTL 400 kV	42	$44.7
11	Saudi Arabia ⇆ GCCIA Interconnection System[3]	Third 600MVA BtB HVDC link 400 kV at Al-Fadhili	0	$0.0
12	Kuwait ⇆ GCCIA Interconnection System[3]	Third 650MVA Auto Trafo plus 4 L Trafo bays	0	$7.4
13	Qatar ⇆ GCCIA Interconnection System[3]	Existing 2*1900MVA 400kV connections	0	$18.0
14	UAE ⇆ GCCIA Interconnection System[3]	Existing 2*1400MVA GCC Grid Lines	0	$0.0
15	Bahrain ⇆ GCCIA Interconnection System[3]	Existing 2*750MVA 400 kV lines	0	$6.8
	Proposed New Interconnections	**Technical Characteristics**	**Distance (km)**	**EPC US$M**
16	Saudi Arabia (Medinah) ⇆ Egypt (Badr)	OHTL HVDC to Tabruk; 20km submarine cable over Gulf of Aqaba; HVAC OHTL 500kV to Badr City, Egypt in service 2024	1,500	$2,500.0
17	Saudi Arabia (Jazan) ⇆ Yemen (Saana/Tiaz/Aden)	Jazan 380kV via HVDC BtB OHTL 400 kV	581	$482.6
18	Tunisia (Bouchemma) ⇆ Libya (Melitia) Stage 1	HVAC OHTL 400kV plus switchbays	250	$125.1
19	Tunisia (Bouchemma) ⇆ Libya (Melitia) Stage 2		250	
20	Saudi Arabia (Qurayyat) ⇆ Jordan (Qatranah)	First Stage HVDC 3 Way Connect Saudi-Jordan-Iraq	165	$425.4
21	Saudi Arabia (Hail) ⇆ Iraq (Karbala)	Hail to Rafha to Arar, Saudi 380kV OHTL and HVDC Arar, Saudi to Karbala, Iraq	729	$683.8
22	Jordan (Amman East) ⇆ Iraq (Qa'im) via Azraq NPS	Second Stage HVDC 3 Way Connect Saudi-Jordan-Iraq	523	$390.0
23	Saudi Arabia (Ras Abu Gamys) ⇆ Oman (Ibri IPP)	HVDC line with Converters both ends	688	$633.5
24	Kuwait (Subiyah) ⇆ Iraq (Basra)	AC Double circuit OHTL 400kV	122	$66.3
25	Kuwait (Jahra) ⇆ Saudi Arabia (Qaisumah/Rafha)	380kV OHTL from Rafha to Qaisumah, Saudi; to 400kV HVDC BtB at border Saudi-Kuwait-Iraq	492	$611.8

Source: Based on WBG (2019e); Gökhan (2014); WBG Consultant, John R. Irving.
Note: JDECO = Jerusalem District Electricity Company

[1] Existing capacity of 1200 MVA is constrained by PPA between Morocco and Algeria. The nominal capacity of existing cross-border interconnections between Morocco and Algeria allows the maximum transfer capacity to be increased from 400MW to 1000MW at no extra cost.
[2] Lack of investment in its domestic transmission infrastructure limits Gaza's capability to import power. Increasing power imports from Egypt to Gaza is contingent on upgrading the existing 220kV network throughout the Sinai region, as well as building a 40km 220kV line from Rafah to Jabalia, Gaza. Cost estimate includes 2018 ESMAP estimation of $200m to strengthen Gaza grid to evacuate power supplied from Egypt.
[3] Costs of upgrades in the GCCIA system are for the additional transformer capacity required at the respective grid 400/220kV substations, assuming the capacity of the existing facilities has been installed in accordance with the CIGRE 2012 paper: "GCC Interconnection Grid: Operational Studies for the GCC Interconnection with United Arab Emirates (UAE)". The nominal capacities otherwise applied for the 2018 studies are based on PPA limitations set by the GCCIA that are currently being reviewed by their consultants. No provision is allocated for upgrading the respective 220kV national networks that supply the GCCIA Member Countries.

Based on an initial desk study (WBG 2019e), table 32 presents preliminary estimates of transmission investment costs for key potential interconnection projects. Following these cost estimations, the 15 selected interconnection reinforcement projects will require investments of about $1.6 billion and the proposed 10 new interconnection projects of almost $5.9 billion. In total, this amounts to $7.5 billion in cross-border transmission project investments for the region. Comparing the total cost estimates to the $35 billion of estimated economic benefits of adding these projects to the regional network (see table 26), indicates that investing $1 billion to expand regional cross-border trade saves $4.6 billion in system costs.

Appendix H details the technical characteristics and estimated project costs (EPC) for the interconnection options listed in table 32.

The growing role of high voltage direct current (HVDC) technology in transmission interconnections is an important trend. As the examples above indicate, HVDC is becoming a key element of power system integration in the MENA region (as well as worldwide)—largely due to its lower unit costs for long-distance transmission projects and its ability to tightly control power flows between independent synchronous systems. In addition, alternating current (AC) power grids are standardized for 50 Hz in some countries and 60 Hz in others and it is impossible to interconnect them. An HVDC link makes this possible by converting AC to direct current (DC) and back again either with a converter station or with two converters separated by an HVDC line.[27] Moreover, HVDC terminals could act like large batteries capable of mitigating intermittency of wind or solar generating plants. The successful operation of the Saudi GCC Grid in pioneering the use of HVDC in its various forms to integrate 50 Hz and 60 Hz high voltage alternating current (HVAC) power systems is a model for enabling economic trading of generation resources by neighboring countries (WBG 2019e).

HVDC and HVAC technologies complement each other quite well for best results in a power system economy. Due to the higher up-front costs of a DC terminal, the HVAC technology is more cost-effective over shorter distances and has its own advantages in transmission and distribution, as its voltages can be more easily stepped up and down. HVAC is the system of choice for all domestic transmission and distribution (T&D) networks. On the other hand, HVDC should be used for connections via (i) undersea cable > 40km; (ii) asynchronous systems (60Hz Vs 50hz) and (iii) long interconnections > 500km without intermediate substations. HVDC is also used to stabilize underlying HVAC systems and has advantages connecting intermittent generation to HVAC systems.[28]

[27] https://www.electricaleasy.com/2016/02/hvdc-vs-hvac.html.
[28] https://www.electricaltechnology.org/

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APPENDIX A. LITERATURE REVIEW

Electricity trade in the Pan-Arab region has been the subject of previous studies. A careful review of these studies has helped guide this report and helped ensure that it provides value through original insights and is based on the most recent data. This section provides an overview of the previous studies and highlights their main contributions.

Some broad points that the previous studies establish are that: gas trade is more favorable for bulk energy trade between countries due to its low cost and because desalination makes it more attractive to have power plants close to load (WBG 2009); interregional gas trading plans have not moved forward in part because of the perception that they would involve higher degrees of dependency and due to uncertainty in gas policies (El-Katiri 2011); and the benefits of electrical interconnections seem to arise because of: (i) differences in load patterns, (ii) differences in plant efficiencies due to age, (iii) expanding benefits for new capacity due to economics of scale/scope, (iv) bypassing implementation obstacles, (v) pooled resources for electricity generation and reserve provision, and (vi) increased capacity for renewables due to more geographical diversity (CESI 2014; El-Katiri 2011; WBG 2009, 2010, 2013).

Past reports also identify some of the obstacles to electricity trade (WBG 2010, 2013; CESI 2014; El-Katiri 2011). Current electricity trade is limited to a small subset of interconnections, with Egypt participating in some trade and the Gulf Cooperation Council (GCC) interconnection providing energy support through its unscheduled energy exchanges (for a total of 922,479 megawatt-hours [MWh] in 2014). Scaling up the existing trade is hindered by: (i) the absence of an independent body to act as a clearing house for trades; (ii) the use of different grid codes in the region; (iii) the different levels of grid reliability; (iv) the limited number of players currently participating in bilateral contracts at the national level; (v) a lack of transparency in the framework for issues such as net transfer capacity; and (vi) the GCC settlement scheme (the GCC unscheduled exchanges are settled in-kind "like for like" but the scheduled exchanges are scheduled at the "true" price, before any subsidy). Bottlenecks within national networks also present technical barriers (for example, voltage limits in Jordan might hinder trade between Egypt and Syria), as does the limited interconnection capacity, which limits the room for trade after reserving capacity for emergency support. Finally, there is limited gas trade due to the limited gas pipeline infrastructure and high liquefied natural gas (LNG) prices that favor exports out of the region.

Recommendations that are broadly endorsed by this body of studies include: (i) developing mechanisms that will make regional coordination easier and facilitate information sharing (CESI 2014); (ii) grid code alignment (WBG 2010); (iii) clear legal frameworks for transaction settlement; and (iv) establishing a clearing house on a regional level (CESI 2014). Actions that some of the reports cite as important for establishing a greater degree of coordination in the region include conducting a rigorous cost/benefit analysis with detailed models of transmission and distribution, price reforms, and the examination of alternative contract options.

The CESI (2014) feasibility study assessing the benefits of electricity trade is the only study that includes most Arab countries (18), provides estimates for benefits over the planning period 2012–30 (at approximately US$40 billion), and incorporates natural gas into the operational benefits (at approximately 86 percent of total benefits due to increased use of natural gas).

However, the CESI study has some important limitations. It does not incorporate renewable profiles at the operational level, it has limited information on reserve sharing and deliverability requirements, and it has limited transmission representation. Furthermore, the recent evolution of fuel prices and cost reductions achieved in renewable generation technology further establish the need for an updated analysis that more accurately reflects the operational benefits of trade while accounting for the latest technology improvements and cost figures.

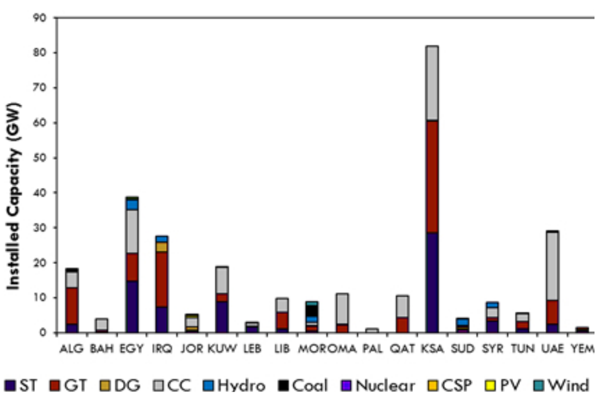
APPENDIX B. DETAILED INPUT ASSUMPTIONS FOR THE ELECTRICITY PLANNING MODEL (EPM)

This Appendix contains figures and charts that complement the information supplied in Section 6 describing the EPM inputs and assumptions.

B.1. INSTALLED CAPACITY AND PLANNED CAPACITY ADDITIONS

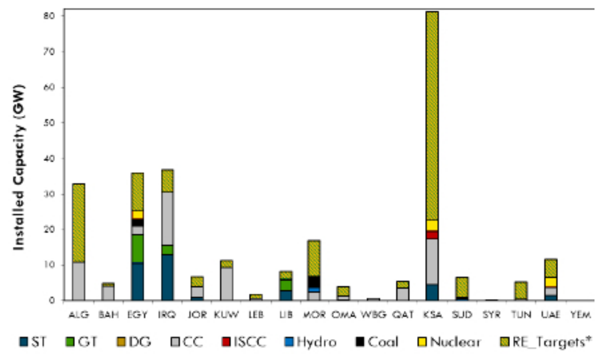
The information in this section was collected from publicly available annual electricity reports, communications with the power system offices of the ministries of energy of some countries and power plants databases such as PLATTS.

Figure 38. Existing Installed Capacity, by 2018, by Technology and Country, in GW



Source: PLATTS database; Electricity and Cogeneration Regulatory Authority (http://www.ecra.gov.sa/en-us); Arab Union of Electricity (http://www.auptde.org/PublicationsCat.aspx?lang=en&CID=284); Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment.
Note: ALG = Algeria; BAH = Bahrain; CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; EGY = Egypt; GT = gas turbine; GW = gigawatt; Hydro = hydroelectricity; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; MW = megawatt; OMA = Oman; WBG = West Bank and Gaza; PV = photovoltaic; QAT = Qatar; ST = steam turbine; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

Figure 39. Planned/Under Construction Capacity, by 2030, by Technology and Country, in GW



Source: Electricity and Cogeneration Regulatory Authority (http://www.ecra.gov.sa/en-us); Arab Union of Electricity (http://www.auptde.org/PublicationsCat.aspx?lang=en&CID=284); Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment
Note: ALG = Algeria; BAH = Bahrain; CC = combined cycle; CSP = concentrating solar power; DG = diesel generator; EGY = Egypt; GT = gas turbine; GW = gigawatt; Hydro = hydroelectricity; IRQ = Iraq; JOR = Jordan; KSA = Saudi Arabia; KUW = Kuwait; LEB = Lebanon; LIB = Libya; MOR = Morocco; MW = megawatt; OMA = Oman; WBG = West Bank and Gaza; PV = photovoltaic; QAT = Qatar; ST = steam turbine; SUD = Sudan; SYR = Syria; TUN = Tunisia; UAE = United Arab Emirates; YEM = Yemen.

B.2. ENERGY DEMAND AND PEAK POWER GROWTH RATES

Table 33 shows the energy and peak power demand average annual growth rates by country. The percentages in the table represent the average annual growth for the planning horizon analyzed (2018–35). For example, in the case of Algeria, a 5 percent energy growth refers to the annual increase in demand experienced every year starting in 2018 until 2035. The same estimation applies to the growth rates for the peak demand. The average energy demand growth rate for the region is 5.6 percent and the average peak power growth rate is 5.4 percent. The countries experiencing the highest average growth rate in energy and peak power demand are: Sudan (16.3 percent for energy and 15.9 percent for peak); Egypt (6.9 percent for energy and 6.7 percent for peak); and Oman (6.6 percent for energy and 6.3 percent for peak). The countries with the lowest average energy and peak demand growth are: Qatar (2.7 percent for energy and peak); Saudi Arabia (3.1 percent for energy and 3 percent for peak); and Lebanon (3.4 percent for energy and 3.3 percent for peak).

Table 33. Projected Average Annual Growth Rates for Energy and Peak Power Demand

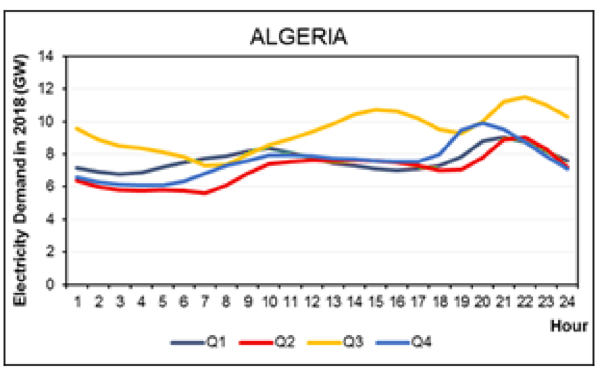
Country	Peak Demand (%)	Energy Demand (%)
Algeria	4.7	5.0
Bahrain	3.8	4.3
Egypt	6.7	6.9
Iraq	1.3	4.9
Jordan	5.3	5.5
Kuwait	4.5	5.0
Lebanon	3.3	3.4
Libya	4.2	4.6
Morocco	5.2	5.6
Oman	6.3	6.6
WB&G	5.5	5.9
Qatar	2.7	2.7
Saudi Arabia	3.0	3.1
Sudan	15.9	16.3
Syria	4.8	4.9
Tunisia	5.4	6.0
UAE	7.9	4.6
Yemen	5.9	6.0

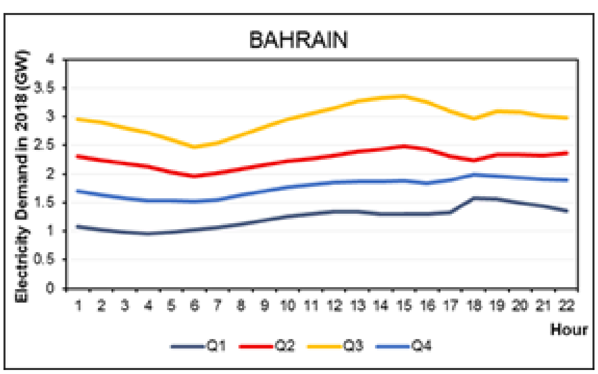
Source: Electricity and Cogeneration Regulatory Authority (http://www.ecra.gov.sa/en-us); Arab Union of Electricity (http://www.auptde.org/PublicationsCat.aspx?lang=en&CID=284); Qatar General Electricity & Water Corporation; Bahrain's Electricity and Water Authority; Oman Electricity Transmission Company; Egyptian Electricity Holding Company 2017; Iraq's Ministry of Energy; Jordan's National Electric Power Company; Electricity of Lebanon; and Moroccan Ministry of Energy, Mining, Water and Environment.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

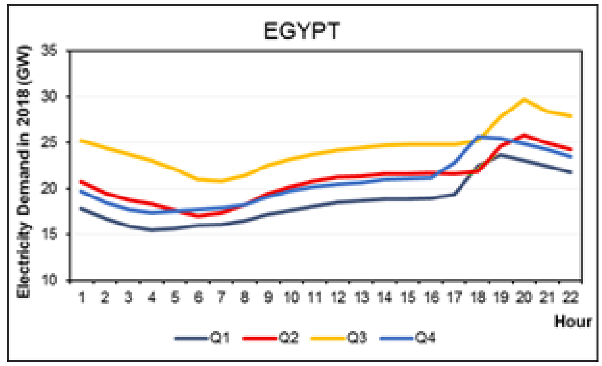
B.3. TYPICAL DEMAND PROFILE

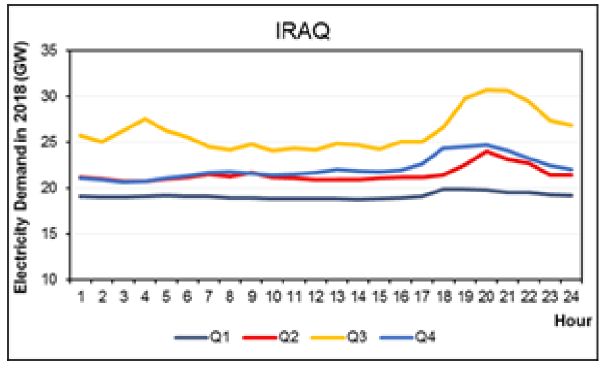
Figure 40 illustrates the hourly, seasonal load profile assumptions by country (CESI 2012), in alphabetical order.

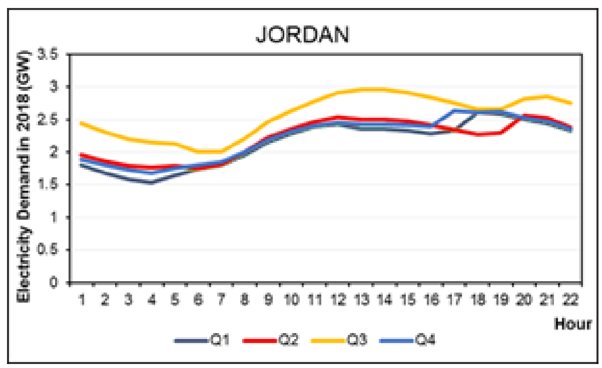
Figure 40. Hourly, Seasonal Load Profiles, in 2018, by Country

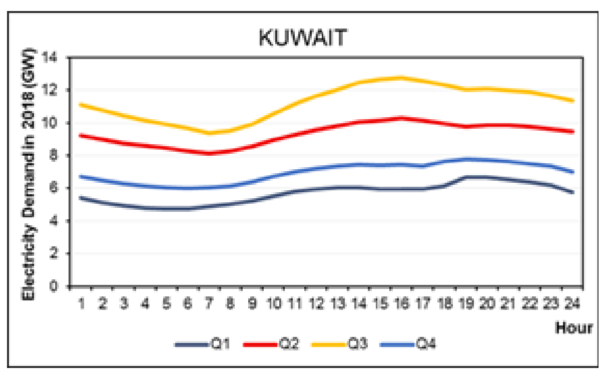


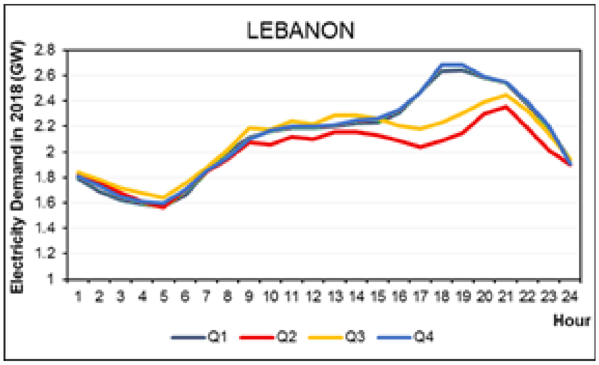


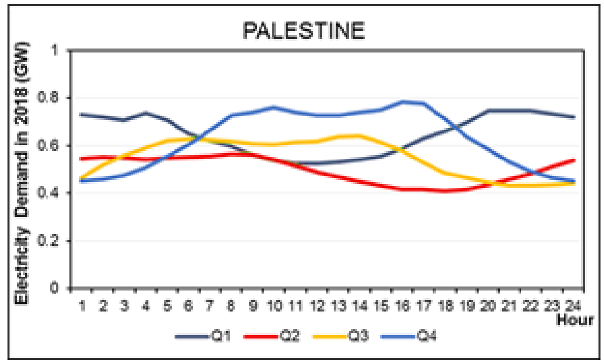


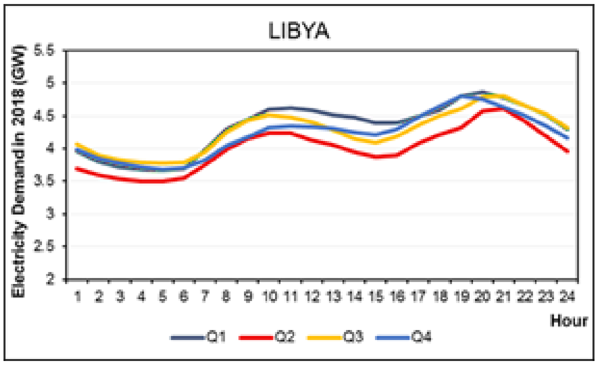


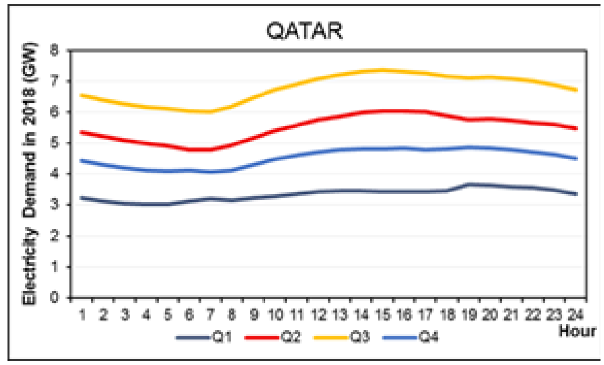


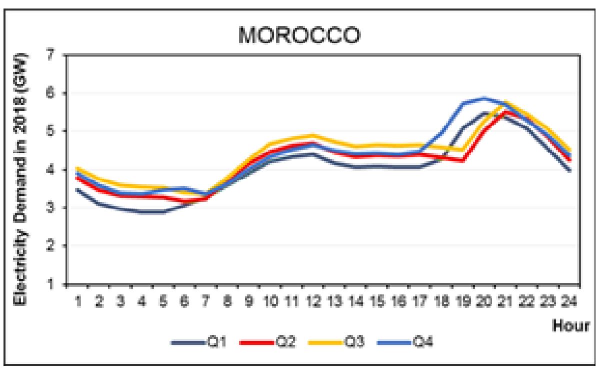


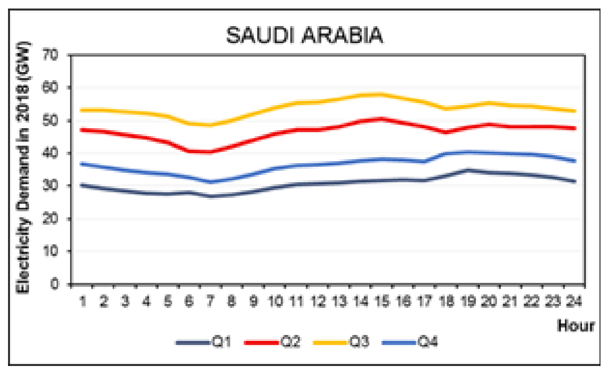

LEBANON
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4

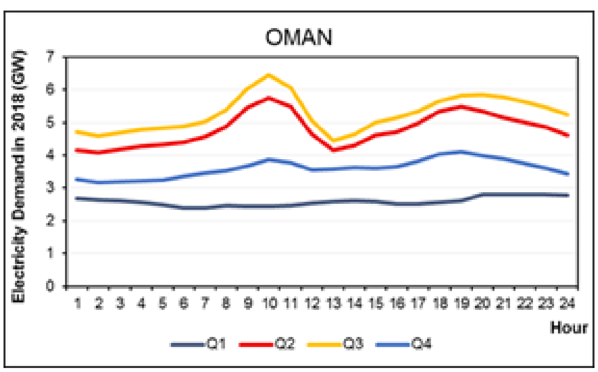

PALESTINE
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4

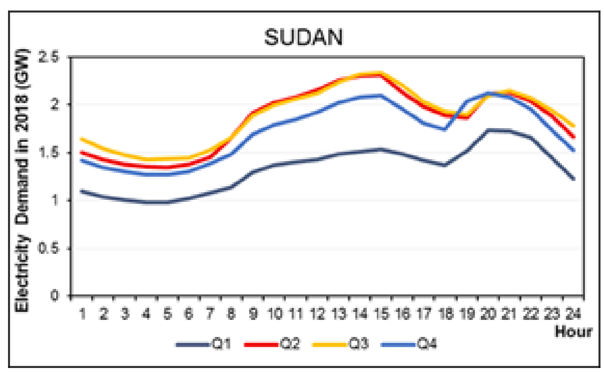

LIBYA
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4

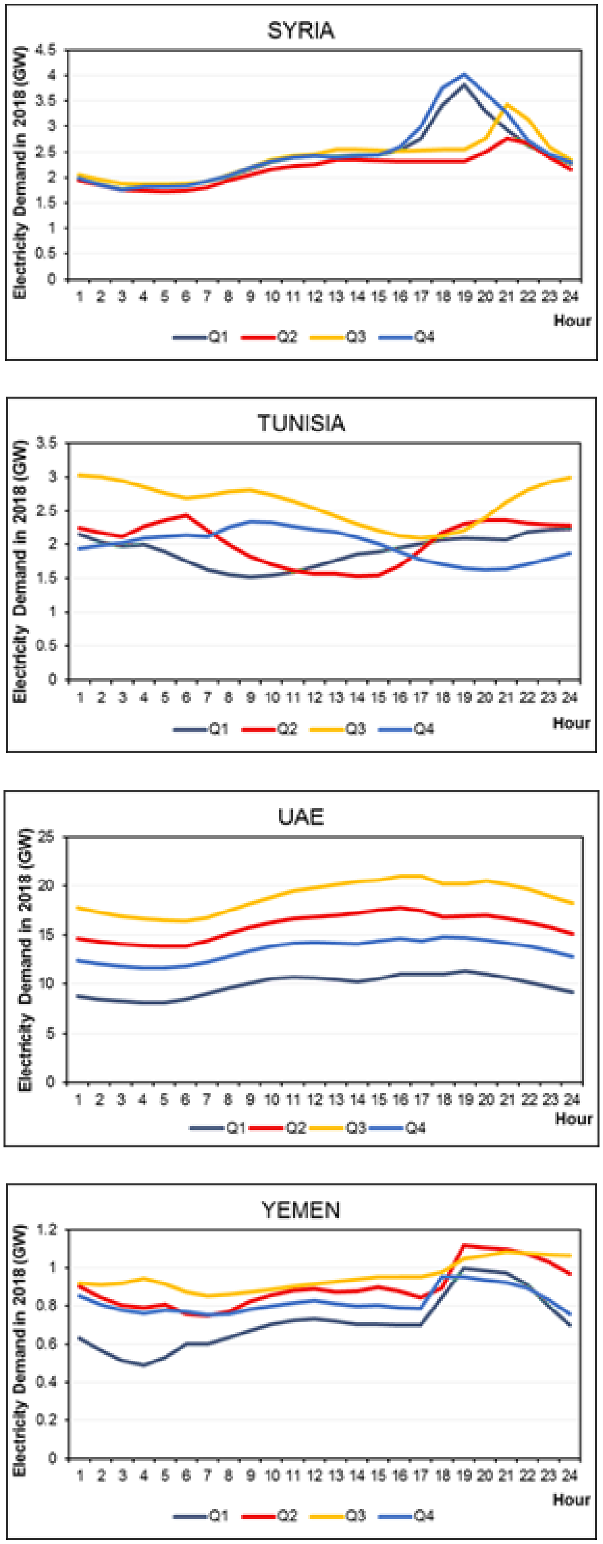

QATAR
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4


MOROCCO
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4


SAUDI ARABIA
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4


OMAN
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4


SUDAN
Electricity Demand in 2018 (GW)
Hour
Q1 Q2 Q3 Q4



Source: CESI 2012.
Note: GW = gigawatt; UAE = United Arab Emirates.

B.4. COSTS OF UNSERVED ENERGY AND UNMET RESERVES

This study employs two criteria to evaluate the power system reliability, cost of unserved energy and cost of unmet reserve capacity requirement. Cost of unserved energy (USE) is defined as the value (in $ per MWh) placed on a unit of electricity not supplied due to an unplanned interruption. Cost of unmet reserve (USR) is defined as the value placed on the inability of the system to meet operational reserves requirements, in terms of margin reserves (in $ per MW) and spinning reserves (in $ per MWh) which may lead to an unplanned interruption. USE and USR are used to provide an economic value to the cost of electricity interruptions to electricity customers and the economy as a whole. These values are used to inform several investment and refurbishment decisions on the electrical power system, with the aim of optimizing the reliability of the network.

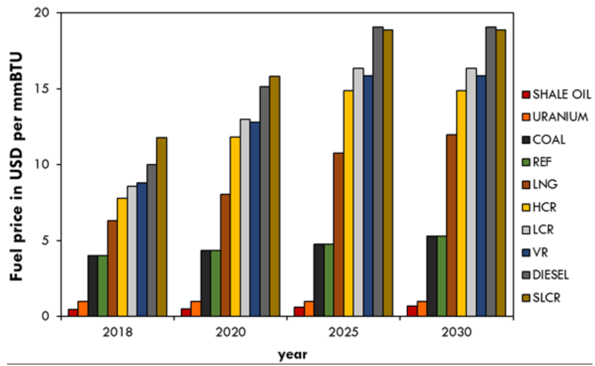
The USE is assessed through the value of lost load (VoLL) which is an exogenous assumption that significantly affects the total nonserved energy in the system and the investment decisions of peaking units. There is not a universally acceptable VoLL and different methods have been applied to estimate a reasonable value for the unserved energy. Typical values used in developed economies vary between US$4,000/MWh and US$40,000/MWh while in developing countries between US$1,000/MWh and US$10,000/MWh. Due to the large number of countries included in this study and the diversity of the reliability requirements on each power system, this study assumes a VoLL of US$500/MWh.

For USR, the capacity expansion model used in this study, EPM, considers two products that the system operator might require generators to provide during operation: (i) planning reserve margin and (ii) spinning reserves. In the first product, planning reserve margin (PRM), planners usually consider an extra capacity requirement (in percentage of projected peak) to account for forecasting error in demand projections. Typical values for the PRM vary between 8–15 percent. EPM considers that interconnections can be accounted for as reserve margin. Note that intermittent units do not contribute toward meeting the PRM requirements at their full capacity but at a fraction specified by the planner, typically as their capacity factor during a set of peak hours. EPM applies an economic penalty to the system when it does not meet the set PRM requirements, called reserve shortfall and the value is assumed to be US$5,000/MW.

The second product, spinning reserves, refers to the unloaded generation that is synchronized and ready to serve additional demand. Spinning reserves provide the capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages, and local area protection. The amount of spinning reserve required depends on several factors that the planner/operator considers such as the load level and the associated forecasting error, the forecasting error attached to the renewable generation, and the size of the largest unit committed on the system to be able to accommodate N-1 outages. In EPM spinning reserve can be provided by interconnections additionally to systemwide reserve requirements. Zonal requirements apply to accommodate for outages on transmission lines connecting adjacent regions/zones/nodes. Also, EPM applies an economic penalty to the system when it does not meet the spinning reserve requirements, called value of lost load of spinning reserve and the value is assumed to be US$1,000/MWh.

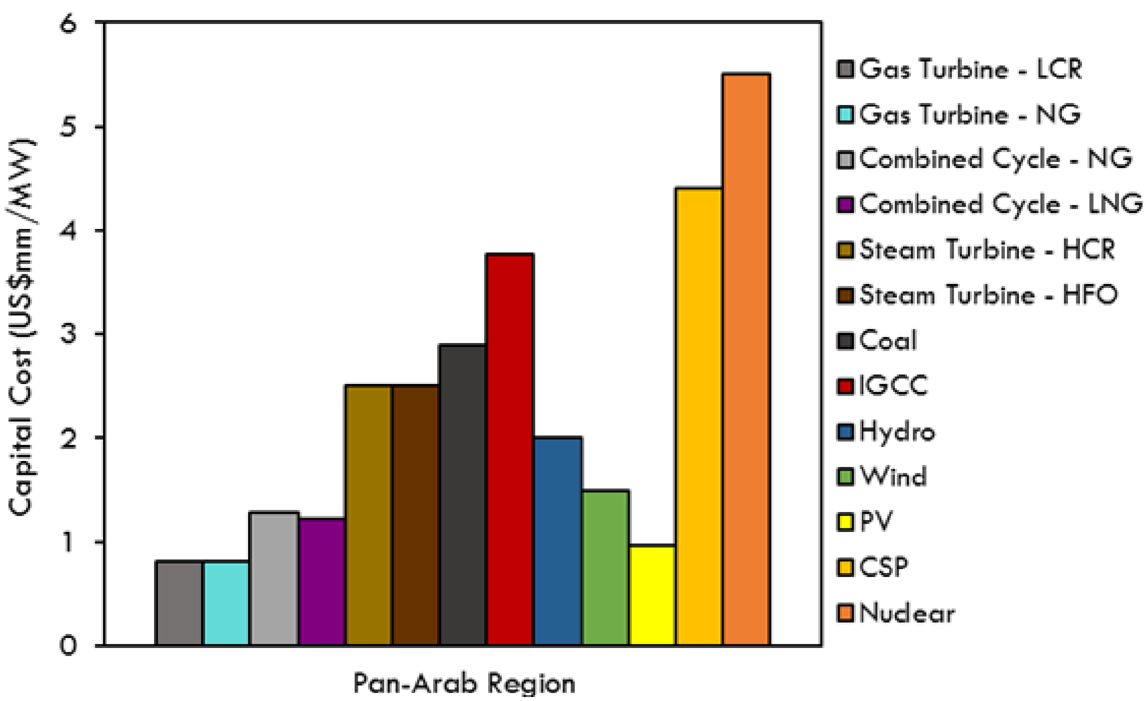
B.5. GENERATION TECHNOLOGIES CAPITAL COSTS AND FUEL PRICES

Figure 42. Regional Prices for Liquid and Solid Fuels ($/MMBTU)



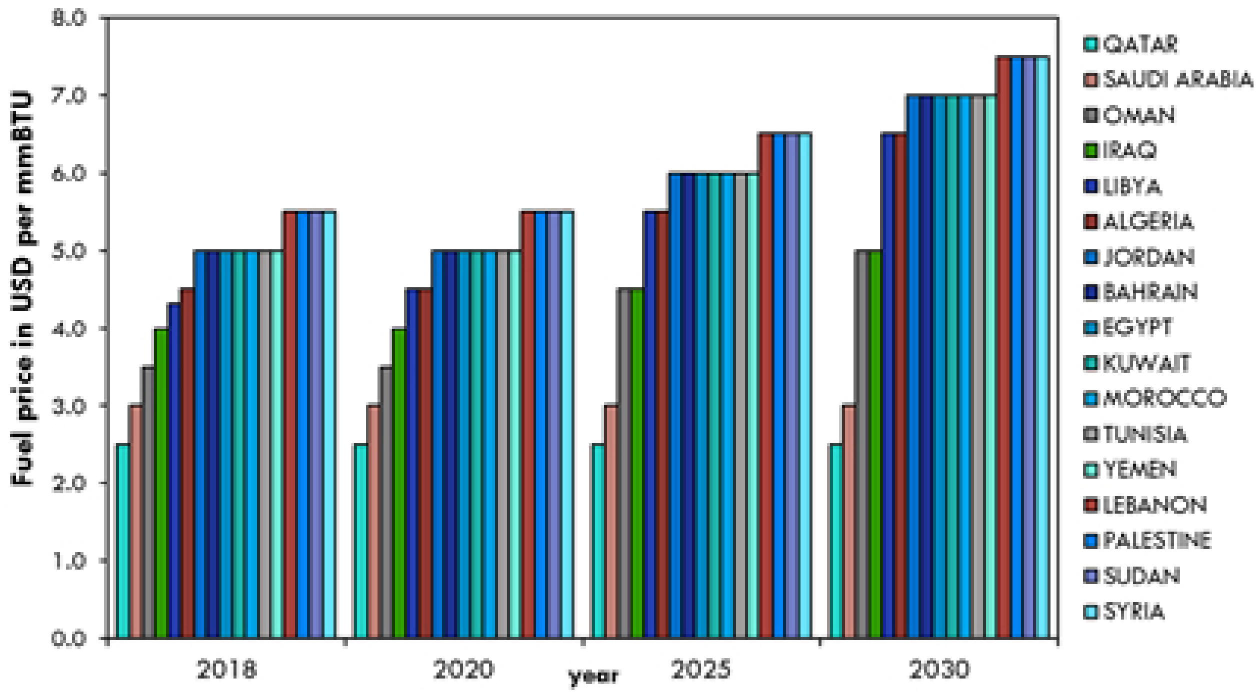
Source: World Bank Commodity Market Outlook, October 2016 (Coal and Crude Oil); U.S. Energy Information Administration, spot prices for fuel oil and other products: http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
Note: HCR = heavy crude oil; LCR = light crude oil; LNG = liquefied natural gas; MMBTU = million British thermal units; REF = refuse; SLCR = Arabian super light crude; VR = Vacuum Residual.

Figure 41. Technology Capital Cost ($ million/MW)



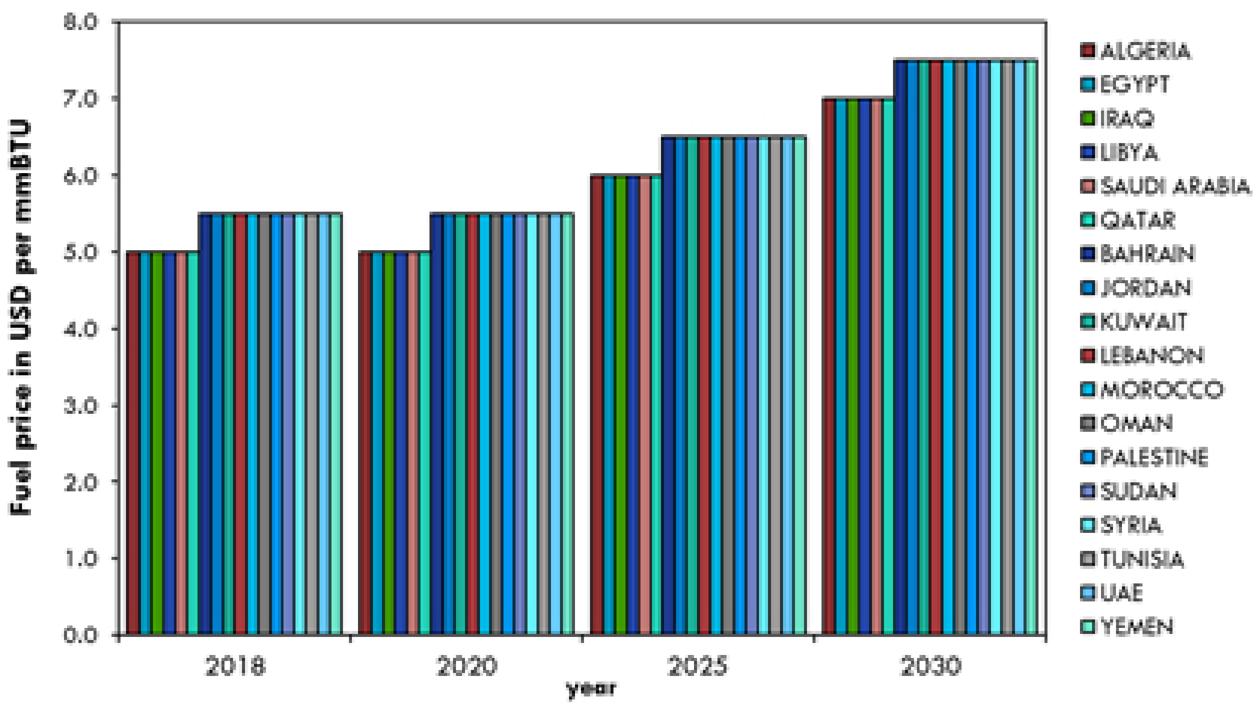
Source: Based on two previous planning studies performed by King Fahad University of Petroleum (KFUPM) in 2011, and the World Bank in 2009; IEA 2014.
Note: CSP = concentrating solar power; HCR = heavy crude oil; HFO = heavy fuel oil; IGCC = Integrated Gasification Combined Cycle; LCR = light crude oil; mm = million; MW = megawatt; NG = natural gas; PV = photovoltaic.

Figure 43. Current Natural Gas Price Projections, in $/MMBTU, by Country



Source: World Bank staff based on World Bank and Ramboll (2017b).
Note: MMBTU = million British thermal units.

Figure 44. International Natural Gas Price Assumptions, Based on EU Hub Prices, in $/MMBTU, by Country



Source: World Bank staff based on World Bank and Ramboll (2017b).
Note: UAE = United Arab Emirates; MMBTU = million British thermal units.

Table 34. Natural Gas Consumption Limit per Year, in Billion Cubic Meters (bcm)

Country	2020	2025	2030	2035
Algeria	100.0	104.0	94.0	94.0
Bahrain	27.0	25.0	24.0	24.0
Egypt	75.0	76.0	70.0	70.0
Iraq	45.0	55.0	58.0	58.0
Jordan	8.0	8.0	8.0	8.0
Kuwait	10.6	18.8	22.2	22.2
Lebanon	2.0	2.0	2.0	2.0
Libya	17.0	20.0	25.0	25.0
Morocco	1.0	5.0	5.0	5.0
Oman	38.0	38.0	34.0	34.0
WB&G	0.4	0.8	1.0	1.0
Qatar	209.0	259.0	259.0	259.0
Saudi Arabia	132.0	132.0	132.0	132.0
Sudan	0.1	0.1	0.1	0.1
Syria	3.0	11.0	11.0	11.0
Tunisia	6.0	6.0	6.0	5.0
UAE	90.0	76.0	76.0	64.0
Yemen[29]	0.4	2.9	2.9	6.3

Source: World Bank and Ramboll 2017a; CIA: https://www.cia.gov/library/publications/the-world-factbook/geos/jo.html.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

[29] Due to the ongoing conflict in Yemen, the natural gas and oil production have decreased dramatically and its LNG facility (production to export to Asian countries) has been put in stand by since. These values for gas limits are an estimation based on current gas production and construction and the outlook for the end of the conflict and the recovery process (CIA Factbook: https://www.cia.gov/library/publications/the-world-factbook/geos/ym.html; World Energy Council: https://www.worldenergy.org/data/resources/country/yemen/gas/; gas production chart: https://ycharts.com/indicators/yemen_natural_gas_production).

APPENDIX C. COUNTRY-SPECIFIC APPROACH TO ESTIMATE CURRENT AND INTERNATIONAL GAS PRICES

Communication Title: Gas price assumptions in Pan-Arab regional energy trade and investments plan modeling
Author: PAEM Modeling Team, World Bank
Date: October 25, 2018

CONTEXT

The PAEM consultations in Morocco (on September 2018) reopened the discussion on gas price assumptions for both the "Local Pricing" and "International Gas Price" scenarios. This note summarizes: (i) two key questions that are yet to be answered; (ii) current gas price assumptions in the model; and (iii) seeks suggestions from the PAEM study team leader to close the current data gap so that the modeling task can move forward with a view to finalizing the results around January 2019. We would like to note that there are other inputs that are being sought from the participating member countries that is already happening and is expected to be completed by mid-October. As such it would be greatly appreciated if revisions to gas prices could be finalized in October too.

C.1. KEY QUESTIONS

Our understanding: The principal concern leveled at the current gas price assumptions is that they are not reflective of true cost of production (as in the Local Pricing scenario), nor reflective of a sustainable energy future for the region because of their reliance on highly volatile international gas prices (as in the second scenario). The question therefore arises as to:

1. **Is there a way to include a new scenario better reflective of marginal cost of production in gas producing countries and apply a suitable approach for projecting it forward that is realistic and sustainable?**

Our understanding: The second issue relates to the details of the International Gas Price scenario which at present relies on the World Bank gas commodity price forecast reflective of a median gas price synonymous to the European gas prices. The debate in the consultations seem to suggest using U.S. gas price benchmark (which is significantly lower than what we are using at present) or Asian liquefied natural gas (LNG) prices (which may be substantially higher than our current set of assumptions). The second question therefore is:

2. **Which regional gas/LNG price should be tied to the International Gas Price scenario?**

There was no clear closure on either of these two issues in the consultations. As the Bank team noted during the discussion, there is no objection to the fundamental idea of using a cost-based estimate of gas. In fact, the Local Pricing scenario is premised precisely on that idea but getting an estimate of gas prices that requires for all gas fields in all relevant countries is a significant task. We had agreed to go back and take a closer look at our assumption that are based on the World Bank Gas Trade report (World Bank and Ramboll 2017b). As we have summarized in the next section, the report—which is by far the most recent authentic estimate of gas prices that we could find in the literature—indeed tries to estimate the marginal cost of gas. Second, we also expressed the opinion that a reliance on a U.S.-centric gas price is not advisable given it is a gas producing/export region that is not a good representative "opportunity cost" for the Middle East and North Africa (MENA) region. The Asian LNG price is indeed an option but may be on the high side for at least a good share of the gas.

C.2. SUMMARY OF PAEM MODEL GAS PRICE ASSUMPTIONS

1. The natural gas prices presented in table 35 were used as gas price assumptions for the World Bank's Electricity Planning Model. These prices were extracted from the above-mentioned report, in which they are described as economic gas prices that result from doing country-specific assumptions for gas prices under existing infrastructure.

2. The country-specific assumptions derived from a combination of using the marginal cost of production, as the economic price, for those countries that have existing infrastructure (that is, existing gas fields) and international gas price (from the EU Hub) +/- transportation costs (US$0.5/ million British thermal units [MMBTU]) for the other countries. Table 36 details the assumptions of this approach.

In the Gas Trade report there is a section (section 10, page 104) attempting to detail the valuation of gas and gas supply approach by country. As an example, figure 45 illustrates the estimated long-run marginal costs (LRMCs) of incremental production in Algeria and in Egypt, which indicates that economic gas prices rely on marginal cost estimates.

The methodology for assessing future marginal costs (to calculate the LRMC[30]) of domestic gas

Table 35. Economic Natural Gas Prices in the Arab Region, in $/MMBTU

Country	2018	2020	2025	2030
Algeria	4.5	4.5	5.5	6.5
Bahrain	5.0	5.0	6.0	7.0
Egypt	5.0	5.0	6.0	7.0
Iraq	4.0	4.0	4.5	5.0
Jordan	5.0	5.0	6	7.0
Kuwait	5.0	5.0	6.0	7.0
Lebanon	5.5	5.5	6.5	7.5
Libya	4.3	4.5	5.5	6.5
Morocco	5.0	5.0	6.0	7.0
Oman	3.5	3.5	4.5	5.0
WB&G	5.5	5.5	6.5	7.5
Qatar	2.5	2.5	2.5	2.5
Saudi Arabia	3.0	3.0	3.0	3.0
Sudan	5.5	5.5	6.5	7.5
Syria	5.5	5.5	6.5	7.5
Tunisia	5.0	5.0	6.0	7.0
UAE	5.0	5.0	5.0	5.0
Yemen	5.0	5.0	6.0	7.0

Source: World Bank and Ramboll 2017a: section 4, page 38, table 10.
Note: UAE = United Arab Emirates; MMBTU = million British thermal units; WB&G = West Bank and Gaza.

Table 36. Country-specific Assumptions for Natural Gas Pricing without New Infrastructure

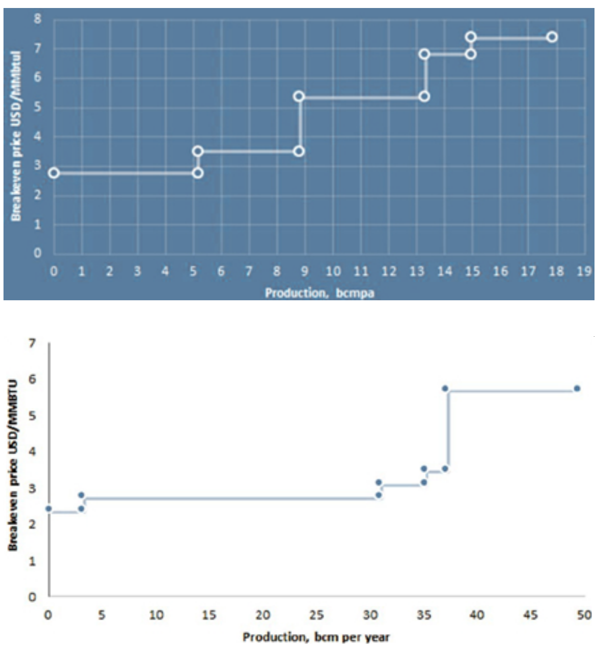
Country	Applied Pricing Assumption	Comment
Algeria	EU price minus transportation cost to the EU	Reference price in Algeria determined by pipeline and LNG connections to the EU prices.
Bahrain	Qatar + transport	Assuming connection to Qatar—close to the cost of developing the ultra-deep fields offshore.
Egypt	EU price	Egypt prices are the highest in the region. The EU price is chosen as a proxy.
Iraq	Marginal production costs	Not connected to the world market and has large reserves. Marginal cost of production drives the cost of gas to the power sector.
Jordan	Egypt + transportation	Assuming that the Arab Gas Pipeline is operational, the prices should be connected to Egypt.
Kuwait	Qatar + transport	Price in Qatar + cost of importing via LNG.
Libya	EU price minus transportation cost to the EU	EU price minus transportation cost to the EU Reference price in Libya determined by the pipeline and connection to the EU prices.
Morocco	Algeria + transportation	This price should not deviate too much from the Algerian prices. Thus, this will be driven by the European price.
Oman	Qatar + transport	Connected to Qatar via the Dolphin Pipeline.
WB&G	Egypt + transportation	Assuming that the Arab Gas Pipeline is operational, the prices should be connected to Egypt.
Qatar	Marginal production costs	Connected to the world market but no possibilities for additional LNG export. The North Field determining the marginal cost.
Saudi Arabia	Marginal production costs	Not connected to the world market and has large reserves. Marginal cost of production drives the cost of gas to the power sector.
Syria	Egypt + transportation	Assuming that the Arab Gas Pipeline is operational, the prices should be connected to Egypt.
Tunisia	Algeria + transportation	This price should not deviate too much from the Algerian prices. Thus, this will be driven by the European price.
UAE	Qatar + transport	Connected to Qatar via the Dolphin Pipeline.
Yemen	Export price Japan—shipping	Minor domestic market—most gas for export. Thus, the price must be LNG price in Japan minus the shipping and transportation costs.

Source: World Bank 2016: 8.
Note: EU = European Union; LNG = liquefied natural gas; UAE = United Arab Emirates.

[30] The breakeven price of gas field production (estimated using production level, reserves, CAPEX, and OPEX for each field) is used as reference for the LRMC, which is defined as the average change in projected operating and capital expenditure attributed to future increases in gas production levels.

supply examined, if possible, the development costs in terms of capital expenditure (CAPEX) and operating expenditure (OPEX) of the four to five largest new gas fields for each country. Data assumptions were retrieved from companies involved in the development of the fields, industry, and governments sources (reports, publications, interviews). When data were not available, estimations were based on previously sanctioned major gas and petroleum projects in MENA. A weighted average capital cost (WACC) of 10 percent was used. (For further details on each country see section 8, pages 77–86, of the report.)

Figure 45. LRMC Incremental Production for Gas Fields in Algeria (up) and Egypt (down), in $/MMBTU



Source: World Bank and Ramboll 2017b—Algeria: section 10, page 123, figure 59; Egypt: section 10, page 164, figure 93.
Note: bcmpa = billion cubic meters per annum; LRMC = long-run marginal cost; MMBTU = million British thermal units.

1. Although sections 8 and 10 of the World Bank and Ramboll (2017b) report offer details on gas valuation for each country, indicate a price range[31] for the value of gas, and provide marginal cost curves for specific countries, some data challenges with these detailed cost curves (figure 45, top) were found which prevented a direct match with the point estimates that appear in the economic gas prices provided in table 35. After detailed verification of the cost curves provided in the report in chapter 10, it is observed that inconsistencies with the data led to the final gas price estimates presented in the report.[32] Specifically, in figure 45, the cost curve for Algeria (up) gives gas prices between US$2.8–7.5/MMBTU to production values ranging 0–19 billion cubic meters per year (bcm/y). Additionally, the report documents that, currently, the gas production of Algeria is approximately 88 bcm/y,[33] which is outside of the range of the cost curve, implying a very high gas price, thus, explaining the assumption made for Algeria in table 36 (to use pipeline and LNG connections to the EU prices to determine the price for Algeria).

   In the case of Egypt, with an estimated gas production of 44 bcm/y, using the cost curve presented in figure 45 leads to a very high price of gas for Egypt (about US$6/MMBTU), resulting in the assumption stated in table 36 for Egypt's gas prices (Egypt prices are the highest in the region. The EU price is chosen as a proxy).

2. However, we are not aware of any better estimates being available having consulted internally and with our external gas pricing advisers.

[31] The lower bound of this range results from netback prices for the major current or future exporting countries, that is, the minimum price producers would be willing to sell gas. The upper bound is a product of how much a power producer would be willing to pay for gas if the alternative was heavy fuel oil (HFO) or coal (considering both new power plants and conversion of existing HFO to gas).

[32] World Bank and Ramboll 2017b: section 4, page 38, table 10.
[33] World Bank and Ramboll 2017b: section 4, page 46, table 11.

APPENDIX D. INTENDED NATIONALLY DETERMINED CONTRIBUTIONS (INDC) SUBMITTED BY SELECTED ARAB COUNTRIES

Country	Date	Summary INDC	Share of global GHG in 2012 (%)
Algeria	4/9/2015	4/9/2015 A 7–22% reduction in GHG emissions by 2030, compared to business-as-usual. The lower end is unconditional whereas the top end of ambition is dependent on provision of climate finance and access to technology.	0.34
Bahrain	24/11/2015	Sets out a number of policies and actions that will contribute to "low greenhouse gas emission development." It highlights its Economic Vision 2030, which seeks to diversify the country's economy and reduce its dependence on oil and gas.	0.06
Egypt	11/11/2015	To achieve "high CO2 mitigation levels" through measures including phasing out energy subsidies within 3–5 years and, potentially, a national carbon market. Also aims to use renewable and nuclear power sources. Requires international support of US$73 billion. Includes section on adaptation.	0.56
Iraq	12/11/2015	[INDC only available in Arabic]	0.30
Jordan	10/9/2015	A 14% reduction in emissions compared to business-as-usual levels by 2030, 1.5% of which is unconditional and 12.5% is conditional upon international support. The country will need around US$5 billion to fulfill the conditional side of its pledge. Lists specific projects that will be implemented to hit the target. Includes adaptation actions.	0.05
Kuwait	24/11/2015	To "move to a low carbon equivalent economy" and avoid an increase in emissions above business-as-usual projections, conditional on international support.	0.19
Lebanon	30/09/2015	An unconditional 15% emissions cut in 2030, compared to business-as-usual, or a conditional 30% reduction. Aims for 15% of power and heat energy to be renewable in 2030, or 20% with international support. Includes section on adaptation.	0.04
Libya		INDC not yet submitted	0.16
Morocco	5/6/2015	An unconditional 13% reduction on business-as-usual emissions by 2030, with a conditional 32% reduction if Morocco receives new sources of finance and enhanced support.	0.15
Oman	19/10/2015	An unconditional 2% emissions cut in 2030, relative to business-as-usual levels. This will be achieved through an unquantified "increase" in renewables and "reduction" in gas flaring. Will develop climate legislation. Includes short section on adaptation. Additional efforts would require international support.	0.12
Qatar	20/11/2015	Focuses on actions that will bring about economic diversification that will also bring down emissions, but does not set a reduction target.	0.20
Saudi Arabia	10/11/2015	An "ambitious" program of renewable energy investment and "economic diversification," along with energy efficiency and carbon capture and storage. Expects emissions savings of up to 130 million tons of CO_2 equivalent in 2030, relative to business-as-usual. Includes section on adaptation.	1.05
Sudan	10/11/2015	To reach 20% renewable share in the power mix by 2030. Includes detailed per-technology aims and targets for energy efficiency. Aims to raise forest area to 25% of Sudan by 2030. Includes section on adaptation. Pledge conditional on international support.	0.94
Syria		INDC not yet submitted	0.15
Tunisia	16/09/2015	A 41% reduction in carbon intensity by 2030, compared to 2010 levels. Specifically, in the energy sector, Tunisia will reduce carbon intensity by 46%. The first 13% of its target is unconditional; the remainder depends on international support. Together, the country's plans for mitigation and adaptation will cost US$20 billion.	0.08
UAE	22/10/2015	To "limit" emissions and increase the share of "clean energy" in the energy mix to 24% by 2021, up from 0.2% in 2014. Includes section on adaptation actions with mitigation co-benefits.	0.39
Yemen	23/11/2015	A 1% emissions cut by 2030 compared to business-as-usual projections, or a 14% cut conditional on international support. Conditional pledge would include 15% of power coming from renewables by 2025. Includes section on adaptation.	0.08

Source: UNFCCC synthesis report 2015, https://www4.unfccc.int/sites/submissions/indc/Submission%20Pages/submissions.aspx
Note: CO2 = carbon dioxide; GHG = greenhouse gas; INDC = Intended Nationally Determined Contribution; UAE = United Arab Emirates.

APPENDIX E. SHARED ECONOMIC BENEFITS AND VALUE OF COMMERCIAL TRADE IN ELECTRICITY IN US DOLLARS PER YEAR[34]

Table 37. Economic Benefit of Trade by Country (USD), Case 1: Current Gas Prices

Country	2020	2025	2030	2035	
Algeria	81,123,285	60,746,199	95,074,072	184,227,830	
Bahrain	39,962,613	92,503,816	134,957,159	151,746,614	
Egypt	140,119,195	676,203,387	798,741,103	2,414,275,560	
Iraq	91,831,806	57,696,977	194,315,781	197,118,420	
Jordan	245,555,365	78,237,407	203,061,523	256,508,633	
Kuwait	30,623,722	241,215,979	449,589,832	449,973,501	
Lebanon	83,972,497	172,890,692	68,304,239	89,201,115	
Libya	3,242,524	31,618,380	401,636,180	527,317,413	
Morocco	70,620,358	55,219,219	32,297,394	46,494,635	
Oman	38,016,799	18,919,008	97,304,485	123,016,362	
WB&G	130,486,420	4,425,108	1,205,838	7,800,796	
Qatar	121,738,397	269,662,876	276,141,804	275,971,673	
Saudi Arabia	118,901,376	517,701,622	955,106,484	1,186,520,684	
Sudan	81,527,373	446,108,715	459,172,223	1,881,493,569	
Syria	332,280,214	191,773,427	98,810,220	154,944,200	
Tunisia	13,414,084	30,457,058	449,591,135	610,630,304	
UAE	100,825,563	144,697,797	159,901,363	167,076,320	
Yemen	-	108,773,148	119,287,891	213,187,089	
Total	$1,724,241,590	$3,198,850,816	$4,994,498,728	$8,937,504,720	$72,809,529,346
Discounted, i=6%	$1,534,568,877	$2,127,418,490	$2,482,112,854	$3,319,071,244	$40,282,354,841

Source: World Bank staff based on EPM output.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 38. Economic Benefit of Trade by Country, Case 3: International Gas Prices

Country	2020	2025	2030	2035	
Algeria	81,071,582	41,117,870	9,485,518	155,564,532	
Bahrain	26,629,265	61,826,812	29,718,355	35,818,696	
Egypt	132,859,184	637,856,144	601,620,338	2,161,013,848	
Iraq	82,300,113	46,410,524	116,762,630	125,372,460	
Jordan	231,016,391	73,924,596	139,108,996	171,788,594	
Kuwait	15,870,089	68,112,099	159,427,011	150,509,832	
Lebanon	83,455,060	171,606,048	66,356,016	82,983,764	
Libya	2,991,882	33,228,893	467,413,270	506,186,444	
Morocco	68,409,090	35,575,810	23,245,778	32,586,897	
Oman	26,408,867	17,940,510	57,396,982	79,439,933	
WB&G	129,817,769	3,894,152	1,504,615	7,715,458	
Qatar	83,979,467	85,366,777	53,611,116	44,040,900	
Saudi Arabia	126,911,614	331,977,325	345,332,115	596,603,683	
Sudan	81,527,373	447,242,437	459,108,694	1,882,322,041	
Syria	316,380,387	178,933,156	108,301,660	150,313,459	
Tunisia	14,563,392	33,332,373	434,593,378	588,507,710	
UAE	108,525,447	125,662,063	112,671,022	117,570,592	
Yemen	-	67,049,499	75,796,890	164,340,746	
Total	$1,612,716,972	$2,461,057,088	$3,261,454,386	$7,052,679,587	$56,557,469,708
Discounted, i=6%	$1,435,312,364	$1,636,743,524	$1,620,842,911	$2,619,114,254	$32,157,666,104

Source: World Bank staff based on EPM output.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

[34] Total and Discounted Total values are calculated over the 2018 – 2035 period.

Table 39. Economic Benefit of Trade by Country, Case 5: International Gas Prices, Carbon Caps

Country	2020	2025	2030	2035	
Algeria	62,934,782	62,244,435	758,750,595	467,484,082	
Bahrain	160,202,534	378,557,889	910,255,766	1,238,924,771	
Egypt	366,785,514	630,041,975	6,829,349,656	5,031,126,784	
Iraq	161,113,550	2,141,156,596	3,651,404,953	3,541,928,282	
Jordan	570,885,550	1,531,662,104	3,838,331,061	3,262,880,341	
Kuwait	304,104,134	636,160,602	3,488,754,065	4,214,071,137	
Lebanon	25,440,601	218,931,485	(22,553,993)	(34,550,148)	
Libya	58,019,482	25,668,299	(221,443,621)	279,465,444	
Morocco	63,976,033	62,971,320	776,293,237	304,167,997	
Oman	83,054,216	18,400,778	704,608,849	1,600,555,457	
WB&G	88,023,981	17,228,397	74,629,301	185,495,565	
Qatar	501,685,594	195,375,633	875,619,506	1,177,333,312	
Saudi Arabia	326,771,179	1,955,565,795	10,322,107,813	10,218,001,307	
Sudan	(40,883,667)	309,957,753	(267,175,637)	1,207,123,652	
Syria	417,366,283	930,736,121	1,097,055,210	1,277,317,936	
Tunisia	22,013,143	(31,788,829)	(189,314,652)	227,479,275	
UAE	576,028,604	227,125,393	2,243,216,817	2,840,455,424	
Yemen	-	105,089,327	87,785,723	777,053,292	
Total	$3,847,521,511	$9,415,085,071	$34,957,674,647	$37,816,313,911	$301,121,356,982
Discounted, i=6%	$3,424,280,448	$6,261,569,302	$17,372,893,322	$14,043,633,429	$150,073,341,233

Source: World Bank staff based on EPM output.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 40. Commercial Value of Export Trade by Country, Case 1: Current Gas Prices

Country	2020	2025	2030	2035	
Algeria	222,768,531	380,219,029	459,952,031	581,141,811	
Bahrain	-	43,801,205	26,955,926	16,638,696	
Egypt	189,983,468	1,053,438,943	1,173,153,898	2,664,529,791	
Iraq	189,991,552	196,120,062	710,020,014	739,815,621	
Jordan	496,955,756	395,883,339	481,592,007	583,296,492	
Kuwait	7,812,451	-	74,761,806	104,568,460	
Lebanon	-	13,750,330	22,405,107	30,731,162	
Libya	24,021,059	434,235,454	962,316,367	1,425,195,513	
Morocco	10,597,911	13,143,724	33,140,105	45,571,265	
Oman	136,349,340	135,737,221	135,468,382	128,501,402	
WB&G	-	-	-	-	
Qatar	279,181,716	580,305,272	644,736,936	661,861,219	
Saudi Arabia	41,256,109	1,772,276,724	3,037,285,313	3,131,273,885	
Sudan	-	260,992	4,869,714	2,112,418	
Syria	332,286,308	592,609,445	573,012,571	740,047,965	
Tunisia	7,498,138	3,950,226	20,381,108	-	
UAE	307,913,045	244,901,740	351,397,850	347,687,798	
Yemen	-	-	-	292,535	
Total	$2,246,615,383	$5,860,633,707	$8,711,449,135	$11,203,266,034	$109,217,217,023
Discounted, i=6%	$1,999,479,693	$3,897,656,137	$4,329,323,333	$4,160,494,377	$59,471,721,243

Source: World Bank staff based on EPM output.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

[34] Total and Discounted Total values are calculated over the 2018 – 2035 period.

Table 41. Commercial Value of Export Trade by Country, Case 3: International Gas Prices

Country	2020	2025	2030	2035	
Algeria	242,783,016	283,062,415	273,616,723	473,689,918	
Bahrain	-	300,726,716	79,664,245	49,600,474	
Egypt	233,739,006	2,256,786,054	2,211,598,535	2,849,818,908	
Iraq	199,523,245	190,950,157	546,623,595	596,183,690	
Jordan	386,336,263	578,868,122	654,350,434	631,851,541	
Kuwait	53,130,327	607,466	144,928,883	149,963,156	
Lebanon	-	13,274,056	21,536,037	23,804,717	
Libya	16,806,958	389,561,909	1,084,908,659	1,465,053,414	
Morocco	11,127,281	40,984,395	146,714,153	116,572,392	
Oman	161,621,447	172,164,812	266,654,778	280,965,115	
WB&G	-	-	-	-	
Qatar	340,290,357	527,695,530	432,085,995	223,126,113	
Saudi Arabia	-	587,604,821	2,461,095,463	3,625,041,427	
Sudan	-	-	2,992,720	2,192,210	
Syria	331,789,091	644,736,246	748,631,863	862,752,259	
Tunisia	7,963,310	7,347,836	100,215,380	-	
UAE	403,912,733	284,314,879	354,982,566	396,619,775	
Yemen	-	-	805,928	2,060,415	
Total	$2,389,023,035	$6,278,685,414	$9,531,405,956	$11,749,295,524	$115,800,394,282
Discounted, i=6%	$2,126,221,996	$4,175,684,398	$4,736,816,752	$4,363,270,301	$62,895,476,371

Source: World Bank staff based on EPM output.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

Table 42. Commercial Value of Export Trade by Country, Case 5: International Gas Prices, Carbon Caps

Country	2020	2025	2030	2035	
Algeria	191,472,058	295,934,872	287,832,237	1,039,628,549	
Bahrain	179,873,506	851,203,261	281,166,821	2,326,739	
Egypt	428,362,856	2,221,443,770	6,574,733,042	6,389,782,642	
Iraq	4,743,367	6,401,350	-	-	
Jordan	886,317,131	2,275,130,596	5,285,463,448	4,757,711,483	
Kuwait	445,973,338	406,313,397	3,517,992,441	3,699,949,041	
Lebanon	-	86,854,012	90,913,679	88,572,936	
Libya	114,356,276	184,627,070	649,692,372	465,151,047	
Morocco	13,355,054	79,490,257	1,450,428,378	710,267,330	
Oman	78,924,290	90,623,396	284,748,761	18,352,804	
WB&G	-	-	-	-	
Qatar	840,205,400	389,001,039	292,096,623	4,869,345	
Saudi Arabia	213,464,388	3,394,780,614	14,612,097,257	14,751,616,022	
Sudan	-	2,529,597	107,061,146	-	
Syria	569,542,693	1,443,638,088	1,538,366,951	1,245,937,527	
Tunisia	45,502,351	122,999,084	136,977,031	410,347,671	
UAE	793,570,458	702,588,874	3,194,967,396	3,854,645,202	
Yemen	-	-	1,305,377	18,412,468	
Total	$4,805,663,167	$12,553,559,277	$38,305,842,961	$37,457,570,805	$330,562,594,952
Discounted, i=6%	$4,277,023,111	$8,348,833,898	$19,036,830,398	$13,910,409,004	$166,557,220,362

Source: World Bank staff based on EPM output.
Note: UAE = United Arab Emirates; WB&G = West Bank and Gaza.

[34] Total and Discounted Total values are calculated over the 2018 – 2035 period.

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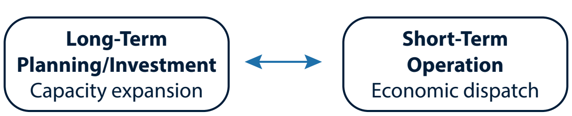
APPENDIX F. ELECTRICITY PLANNING MODEL (EPM) METHODOLOGY

The World Bank's Electricity Planning Model (EPM) is a long-term, multiyear, multizone capacity expansion model with economic dispatch. The objective of the model is to minimize at once the sum of fixed and variable generation costs (discounted for time) for all zones and all years considered, subject to the following properties and constraints:

- Demand equals the sum of generation and nonserved energy,
- Available capacity is existing capacity plus new capacity minus retired capacity,
- Generation does not exceed the max and min output limits of the units,
- Generation is constrained by ramping limits,
- Reserves are committed every hour to compensate forecasting errors,
- Renewable generation is constrained by wind and solar hourly availability,
- Excess energy can be stored in storage units to be released later or traded between the other zones, and
- Transmission network topology and transmission line thermal limits.

The model is an abstract representation of the real power systems with certain limitations described in more detail in section F.3.

Figure 46. Structure of the World Bank Electricity Planning Model



Multi-year multi-zone capacity expansion with economic dispatch

Source: World Bank staff.

INPUTS AND OUTPUTS OF THE MODEL

EPM requires a set of detailed input parameters that characterizes the power system of each of the countries analyzed in this study. These inputs are used to determine specific outputs that later are processed to assess the potential benefits of engaging in regional electricity trade. Table 43 summarizes the main inputs and outputs of the model. On the inputs side, hourly electric demand and renewable resources profiles are key to capture the seasonal variations that impact the performance of the power system. Also, generation technologies costs coupled with fuel prices and the amount of fuel available for generation would help determine the type of capacity additions. On the outputs side, changes in wholesale electricity costs, fuel consumption, and total CO_2 emissions, together with the volume of electricity traded, will be relevant to assess the potential gains from trade.

Table 43. EPM Main Inputs and Outputs

Inputs	Outputs
Wind resource historical hourly availability	Optimal generation investments
Solar resource historical hourly availability	Capacity utilization factor of individual technologies
Demand historical hourly data and growth expectation	Energy contribution of individual technologies
Fuel prices and fuel consumption limits	Fuel consumption
Topology and thermal limits of the transmission lines	Carbon dioxide emissions from the power sector
Fixed and variable cost of generating technologies	Wholesale electricity prices
Flexibility options available (hydro, storage, demand-side management, etc.)	Volume and value of electricity traded among zones/jurisdiction

Source: World Bank staff.
Note: EPM = Electricity Planning Model.

MODELING ASSUMPTIONS

The model is derived based on the following assumptions:

1. The market participants are not strategic, and they behave in a perfectly competitive manner, that is, the power plant owners submit their true costs as bids.

2. The projected demand is considered perfectly inelastic, which implies that the maximization of the social welfare can be replaced by minimization of the system cost.
3. The trade among regions is economically efficient (optimal), which translates to a single objective of minimization of cost for all regions. Please note that in practice, achievement of the economically optimal outcome will probably require the establishment of an independent system operator for the whole region.
4. The pricing is efficient and does not provide incentives to market participants to deviate from the optimal behavior.

WHAT CAN THE MODEL DO?

- Determine hourly cost of electricity with trade for different countries and zones, which is essential to value the energy traded.
- Determine the cost to the consumer.
- Determine where and by how much renewable resources should be deployed to maximize their value to the system—critical issue in current planning efforts.
- Determine the optimal capacity additions over time to complement renewable generation accounting for existing generating units, energy storage, demand-side response, and/or a carbon constraint.
- Determine the optimal retirement schedule of the existing units over time.
- Assess the utilization of the transmission lines (important to design trade contracts).
- Determine the impact of different market conditions (for example, fuel prices, fuel subsidies, carbon limits, etc.) and technology cost assumptions on the optimal capacity expansion plan and the optimal energy mix.
- Determine the cost of implementing specific environmental policies: renewable portfolio standards, cap on carbon emissions, tax on carbon emissions, and carbon emissions rate.

The power system planning model is described in detail in sections F.2–F.5.

F.1. NOTATION

INDICES AND SETS

$d \in D$	where D is the set of types of days or weeks
$f \in F$	where F is the set of fuels
$g \in G$	where G is the set of generators that can be built or the set of technology-specific types of aggregated generators
$q \in Q$	where Q is the set of seasons or quarters
$t \in T$	where T is the set of hours considered per day (usually 24)
$y \in Y$	where Y is the set of years considered in the planning model
$z, z2 \in Z$	where Z is the set of zones/regions modeled
$sc \in S$	where S is the set of flags and penalties used to include/exclude certain features of the model

Subsets considered	
$EG, NG \in G$	where EG and NG is a partition of set G and the former (EG) contains generators existing at the starting year of the planning horizon and the latter (NG) contains candidate generators[35]
$MD \in D$	where MD is a subset of days the planner expects the minimum load levels to be binding
$PT, OPT \in T$	where PT and OPT is a partition of set T that distincts hours in peak and off-peak hours
$RE \in F$	where RE is a subset of set F considered as renewable according to the regulator's criteria[36]
$RG \in G$	where MD is a subset of days the planner expects the minimum load levels to be binding
$map_{g,f}$	includes valid combinations of fuels and generators; subset of the set $G \times F$

[35] The generators already planned are included in any of the two sets depending on criteria such as their capacity, status of their construction process, etc.
[36]Type of resources considered as renewables might be different from country to country or state to state. For example, some states do not include hydropower towards their renewable targets (for example, California does not count large hydropower toward the renewable portfolio standards) while others such as Oregon do (DSIRE n.d.).

VARIABLES

Nonnegative decision variables	
$build_{g,y}$	Investment in MW
$cap_{g,y}$	Capacity available at year y in MW
$emissions_{z,y}$	Emissions of carbon dioxide in tons
$emissions\_Zo_{z,y}$	Emissions of carbon dioxide in tons per zone z
$fuel_{z,f,y}$	Fuel consumption in MMBTU
$gen_{g,f,q,d,t,y}$	Generator output in MW
$genCSP_{g,z,q,d,t,y}$	Power output of the solar panel in MW
$retire_{g,y}$	Capacity in MW retired
$reserve_{g,q,d,t,y}$	Spinning reserve requirement met in MW
$storage_{z,q,d,t,y}$	Level of energy in MWh stored at zone z
$storage\_inj_{z,q,d,t,y}$	Power level in MW at which the storage unit g is charged during hour (q,d,t)
$storage\_out_{z,q,d,t,y}$	Power level in MW at which the storage unit g is discharged during hour (q,d,t)
$storageCSP_{g,z,q,d,t,y}$	Level of energy in MWh stored in CSP unit at zone z
$storageCSPinj_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is charged during hour (q,d,t)
$storageCSPout_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is discharged during hour (q,d,t)
$trans_{z,z2,q,d,t,y}$	Active power in MW flowing from z to $z2$
$unmetDem_{z,q,d,t,y}$	Unmet demand in MW (or equivalently violation of the load balance constraint)
$unmetDem_{z,q,d,t,y}$	Unmet demand in MW (or equivalently violation of the load balance constraint)
$unmetRes_{z,y}$	Violation of the planning reserve constraint in MW
$unmetSResZo_{z,q,d,t,y}$	Violation of the zonal/regional spinning reserve constraint in MW
$unmetSResSY_{q,d,t,y}$	Violation of the system-level spinning reserve constraint in MW

Variables for modeling objective function	
$carboncost_{z,y}$	Carbon tax payments by generators
$fixedcost_{z,y}$	Fixed operation and maintenance cost along with capital payments in constant prices
$npvcost$	Net present value of power system cost over the whole planning horizon; objective function that optimization model tries to minimize
$reservecost_{z,y}$	Cost to procure spinning reserves
$totalcost_{z,y}$	Annual system cost in constant prices
$usecost_{z,y}$	Damage/economic loss in constant prices because of unmet demand
$usrcost_{z,y}$	Penalty in constant prices for unmet spinning reserve requirements
$variablecost_{z,y}$	Variable cost including fuel and variable operation and maintenance cost in constant prices

PARAMETERS

$Availability_{g,q}$	Availability of unit g to generate power in quarter q
$Annual\_built\_limit_y$	Maximum amount of MW allowed to be built per year
$CapCost_{NG,y}$	Capital cost in US$ or other monetary unit per MW
$Carbon\_emission_f$	Equivalent tons of CO_2 emitted per MMBTU of fuel consumed
$Carbon\_tax_y$	Carbon price in US$ per equivalent tons of CO_2
$Commission\_year_g$	Earliest commission year for generators
CRF_{NG}	Capital Recovery Factor[37]
$CSP\_storage$	CSP storage capacity in hours
$Demand_{z,q,d,t,y}$	Hourly load level in MW in hour t, day d, quarter q, and year y
$DRate_y$	Discount rate; real or nominal if cost parameters in real or nominal terms, respectively
$Duration_{q,d,t,y}$	Duration of each time slice (block) in hours
$FieldEfficiency_{CSP}$	Efficiency of the CSP solar field
$FixedOM_{g,y}$	Fixed operation and maintenance cost in US$ or other monetary unit per MW
$FuelPrice_{f,y,z}$	Fuel price in US$/MMBTU
$GenCost_{g,f,y}$	Generation variable cost (fuel and VOM) in US$ or other monetary unit per MWh
Gen_zone_g	Contains the zone index of the zone the generator belongs to
$HeatRate_{g,f}$	Heat Rate in BTU/MWh
$Life_{NG}$	Operating life for new generators
$LossFactor_{z,z2,y}$	"Linearized" loss factor in percentage of active power flowing on transmission line
$MaxCapital$	Maximum amount of annualized capital payments in US$ billions over the horizon
$MaxFuelOff_{f,y}$	Maximum amount of fuel f (in BTU) that can be consumed in year y
$MaxNewCap_{NG}$	Maximum capacity to be built over the horizon in MW
$MinCapFac_g$	Minimum capacity factor (to reflect minimum load requirements)
$OverLoadFactor_g$	Overload factor of generator g, as percentage of capacity
$PlantCap_{EG}$	Existing capacity at initial year in MW
PRM_z	Planning reserve margin per zone z
$RampDn_g$	Ramp-down capability of generator g, as percentage of capacity installed[38]
$RampUp_g$	Ramp-up capability of generator g, as percentage of capacity installed
$ResCost_g$	Cost to provide reserves in US$ or other monetary unit per MWh

[37] $CRF_{NG} = \frac{WACC}{1-\frac{1}{(1+WACC)^{Life_{NG}}}}$

[38] Note that ramping capabilities of generator are usually expressed in MW/min and then based on the minutes the operating reserve requirement is defined, we can estimate the capability in MW and subsequently express it in percentage of installed capacity. In the United States, 10 minutes is typical time for operating reserves and 5 minutes for regulation reserves.

$ResOffer_g$	Percentage of the generator's unit that qualifies as a reserve offer
$RESVoLL$	Violation penalty of planning reserve requirement in US$/other monetary unit per MW
$Retirement\_year_{EG}$	Latest retirement year for existing generators
$ReturnRate_y$	Discount factor at the starting year of stage ending at year y
$RPprofile_{g,RE,q,d,y,t}$	Renewable generation profile in percentage of installed (rated) capacity
$SolarMultipleCSP$	CSP output to solar field ratio
$SResSY_y$	System-level spinning reserve constraint in MW
$SResZo_{z,y}$	Zonal/regional spinning reserve constraint in MW
$StageDuration_y$	Duration of a stage represented by year y in years
$StartYear$	First year of the horizon
$Storage\_capacity_{z,y}$	Capacity of storage unit
$Storage\_efficiency_{z,y}$	Efficiency of storage (per charging cycle)
$Storage\_energy_{z,y}$	Energy capability of storage unit
$Sy\_emission\_cap_y$	Cap on CO_2 emissions within the system at year y in equivalent tons
$Topology_{z,z2}$	Network topology: contains 0 for nonexisting lines and 1 or -1 to define the direction of positive flow over the line
$TransLimit_{z,z2,q,y}$	Transmission limits by quarter q and year y
$TurbineEfficiency_{CSP}$	Efficiency of the CSP power block
$VarOM_{g,y}$	Variable operation and maintenance cost in US$ or other monetary unit per MWh
$VOLL$	Penalty/economic loss considered per MWh of unmet demand
$WACC$	Weighted average cost of capital
$WeightYear_y$	Weight on years
$Zo\_emission\_cap_{y,z}$	Cap on CO_2 emissions within zone z and year y in equivalent tons
$zone\_index_z$	Index of zone z, unique number assigned to zone z

F.2. MODEL FORMULATION

Objective Function and Its Components

$$npvcost = \sum_{z,y} ReturnRate_y * WeightYear_y * totalcost_{z,y} \tag{1}$$

$$totalcost_{z,y} = fixedcost_{z,y} + variablecost_{z,y} + reservecost_{z,y} + usecost_{z,y} + usrcost_{z,y} + carboncost_{z,y} \tag{2}$$

$$fixedcost_{z,y} = \sum_{g \in NG} CRF_{NG} * CapCost_{NG,y} * cap_{g,y} * + \sum_{g} FixedOM_{g,y} * cap_{g,y} \tag{3}$$

$$variablecost_{z,y} = \sum_{g \in Z,f,q,d,t} GenCost_{g,f,y} * Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \tag{4}$$

$$reservecost_{z,y} = \sum_{g \in Z,q,d,t} ResCost_g * Duration_{q,d,t,y} * reserve_{g,q,d,t,y} \tag{5}$$

$$usecost_{z,y} = \sum_{q,d,t} VOLL * Duration_{q,d,t,y} * unmetDem_{z,q,d,t,y} \tag{6}$$

$$\begin{aligned} usrcost_{z,y} = & \sum_{q,d,t} RESVoLL * unmetRes_{z,y} \\ & + \sum_{z,q,d,t,y} Duration_{q,d,t,y} * SRESVoLL * unmetSResZo_{z,q,d,t,y} \\ & + \sum_{q,d,t} Duration_{q,d,t,y} * SRESVoLL * unmetSResSY_{q,d,t,y} \end{aligned} \tag{7}$$

$$carboncost_{z,y} = \sum_{g \in Z,f,q,d,t} Duration_{q,d,t,y} * carbon_{tax_y} * HeatRate_{g,f} * carbon_{emission_f} * gen_{g,f,q,d,t,y} \tag{8}$$

Transmission Network Constraints

$$\begin{aligned} \sum_{g \in Z,f} gen_{g,f,q,d,t,y} - \sum_{z2} trans_{z,z2,q,d,t,y} + \sum_{z2} (1 - LossFactor_{z,z2,y}) * trans_{z2,z,q,d,t,y} + storage_{out_{z,q,d,t,y}} - storage_{inj_{z,q,d,t,y}} \\ + unmetDem_{z,q,d,t,y} = Demand_{z,q,d,t,y} \end{aligned} \tag{9}$$

$$trans_{z,z2,q,d,t,y} \leq TransLimit_{z,z2,q,y} \tag{10}$$

System Requirements

$$\sum_{g} reserve_{g,q,d,t,y} + unmetSResSY_{q,d,t,y} \geq SResSY_y \tag{11}$$

$$\sum_{g \in Z} reserve_{g,q,d,t,y} + unmetSResZo_{z,q,d,t,y} + \sum_{z2} (TransLimit_{z2,z,q,y} - trans_{z2,z,q,d,t,y}) \geq SResZo_{z,y} \quad \forall\, z, q, d, t, y \tag{12}$$

$$\sum_{g \in Z} cap_{g,y} + unmetRes_{z,y} + \sum_{z2} \sum_{q} TransLimit_{z2,z,q,y} \geq (1 + PRM_z) * \max_{q,d,t} Demand_{z,q,d,t,y} \quad \forall\, z, y \tag{13}$$

Generation Constraints

$$\sum_f gen_{g,f,q,d,t,y} + reserve_{g,q,d,t,y} \leq \left(1 + OverLoadFactor_g\right) * cap_{g,y} \tag{14}$$

$$reserve_{g,q,d,t,y} \leq cap_{g,y} * ResOffer_g \tag{15}$$

$$\sum_f gen_{g,f,q,d,t-1,y} - \sum_f gen_{g,f,q,d,t,y} \leq cap_{g,y} * RampDn_g \quad \forall\, t > 1 \tag{16}$$

$$\sum_f gen_{g,f,q,d,t,y} - \sum_f gen_{g,f,q,d,t-1,y} \leq cap_{g,y} * RampUp_g \quad \forall\, t > 1 \tag{17}$$

$$\sum_f gen_{g,f,q,d,t,y} \geq MinCapFac_g * cap_{g,y} \qquad \forall d \in M \tag{18}$$

$$\sum_{f,d,t} Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \leq Availability_{g,q} * \sum_{d,t} Duration_{q,d,t,y} * cap_{g,y} \tag{19}$$

Renewable Generation

$$gen_{g,f,q,d,t,y} \leq RPprofile_{g,RE,q,d,y,t} * cap_{g,y} \qquad \forall\, RE \notin CSP \tag{20}$$

Concentrated Solar Power (CSP) Generation

$$storageCSP_{g,z,q,d,t,y} \leq cap_{g,y} * CSP\_storage \qquad \forall\, map(g, CSP) \tag{21}$$

$$genCSP_{g,z,q,d,t,y} = RPprofile_{z,RE \in CSP,q,d,t} * cap_{g,y} * \frac{SolarMultipleCSP}{TurbineEfficiency_{CSP} * FieldEfficiency_{CSP}} \tag{22}$$

$$\sum_{f \in CSP} gen_{g,f,q,d,t,y} \leq cap_{g,y} \tag{23}$$

$$\sum_{f \in CSP} genCSP_{g,z,q,d,t,y} * FieldEfficiency_{CSP} - storageCSPinj_{g,z,q,d,t,y} + storageCSPout_{g,z,q,d,t,y} = \frac{gen_{g,f,q,d,t,y}}{TurbineEfficiency_{CSP}} \quad \forall\, g, z, q, d, t, y \tag{24}$$

$$storageCSP_{g,z,q,d,t,y} = storageCSP_{g,z,q,d,t-1,y} + storageCSPinj_{g,z,q,d,t,y} - storageCSPout_{g,z,q,d,t,y} \tag{25}$$

Time Consistency of Power System Additions and Retirements

$$cap_{g \in EG,y} = cap_{EG,y-1} + build_{EG,y} - retire_{EG,y} \qquad \forall\, ord(y) > 1 \tag{26}$$

$$cap_{g \in NG,y} = cap_{NG,y-1} + build_{NG,y} \qquad \forall\, ord(y) > 1 \tag{27}$$

$$cap_{g \in NG,y} = PlantCap_{EG} \qquad ord(y) = 1 \tag{28}$$

$$cap_{g,y} = 0 \quad \forall\, (y, g):\ (ord(y) - 1) * StageDuration_y + StartYear < Commission\_year_g \tag{29}$$

$$cap_{g,y} = 0 \quad \forall\, (y, g \in EG):\ (ord(y) - 1) * StageDuration_y + StartYear > Retirement\_year_{EG} \tag{30}$$

Storage Constraints	
$storage_{z,q,d=1,t=1,y} = 0$	(31)
$storage_{z,q,d,t>1,y} = storage_{z,q,d,t-1,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d,t-1,y} - storage\ out_{z,q,d,t-1,y}$	(32)
$storage_{z,q,d,t=1,y} = storage_{z,q,d-1,t=241,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d-1,t=24,y} - storage\ out_{z,q,d-1,t=24,y}$	(33)
$\sum_{t \in PT} storage\ out_{z,q,d,t,y} \leq Storage_{efficiency_{z,y}} * \sum_{t \in OPT} storage\_inj_{z,q,d,t,y}$	(34)
$storage\ inj_{z,q,d,t,y} \leq Storage\_capacity_{z,y}$	(35)
$storage\ out_{z,q,d,t,y} \leq Storage\_capacity_{z,y}$	(36)
$storage_{z,q,d,t,y} \leq Storage\ energy_{z,y}$	(37)
$storage\ out_{z,q,d,t,y} \leq storage_{z,q,d,t,y}$	(38)
$storage\ inj_{z,q,d,t,y} \leq Storage\ energy_{z,y} - storage_{z,q,d,t,y}$	(39)

Investment Constraints	
$\sum_{y} build_{g \in NG,y} \leq MaxNewCap_{NG}$	(40)
$build_{g \in NG,y} \leq Annual\ built\ limit_y * WeightYear_y$	(41)
$fuel_{z,f,y} \leq MaxFuelOff_{f,y}$	(42)
$fuel_{z,f,y} = \sum_{g \in Z,q,d,t} Duration_{q,d,t,y} * HeatRate_{g,f} * gen_{g,f,q,d,t,y}$	(43)
$\sum_{y,g \in NG} ReturnRate_y * pweight_y * CRF_{NG} * CapCost_{NG,y} * cap_{g,y} \leq MaxCapital$	(44)

Environmental Policy	
$emissions\_Zo_{z,y} = \sum_{g \in Z,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y}$	(45)
$emissions\_Zo_{z,y} \leq Zo\_emission\_cap_{y,z}$	(46)
$emissions_{z,y} = \sum_{g,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y}$	(47)
$emissions_{z,y} \leq Sy\_emission\_cap_y$	(48)

F.3. DESCRIPTION OF THE MODEL

INDICES AND SETS

All sets used in the formulation can be classified in two major categories: time and power system related. Four sets belong to the first category: *D, Q, T, Y* which represent different time scales considered in the model: days, quarters, hours, and years. Hour is the smallest unit of time used in this formulation and we could use the same formulation using just one set for time containing as many hours as the set $D \times Q \times T \times Y$. It is convenient though to keep all the four sets since they reveal some fundamental assumptions of the model: (i) days are used to reflect the chronological sequence of the time slices used for ramping and storage constraints as we will further explain in the constraints section; (ii) quarters are used to reflect seasonality in the load patterns, the availability of thermal power units, and the thermal limits of transmission lines; (iii) years are used to represent annual trends on demand growth and keep track of the lifetime of units; and finally (iv) hours are commonly used as the smallest time unit in long-term models since the day-ahead scheduling models schedule generation units on an hourly basis.

Three sets are power system related. Set *G* includes all generating units. Depending on the size of the system, we might decide to use set g to model individual units of the power system for a small system or aggregated units that represent multiple units of the same technology for a large system. We use the term technology to refer to different technologies or different fuels used: for example, coal steam turbines, natural gas combined cycle, natural gas combustion turbines, wind farms, solar photovoltaic panels, geothermal, hydropower, and diesel generators. Depending on the resources available in a country, some technologies might not be present. As the model stands now, elements of set G are mapped to sets *F* and *Z*, which stand for fuel and zones, respectively. Set *Z* is one of the major sets used in power systems since the power system is a network and physical laws (widely known as Kirchhoff's laws) govern the flow of power over the transmission lines. Given that, a set such as set *Z* which captures the spatial dimension of the system is necessary. At the finest granularity, set *Z* might contain buses of the power system but in case we model larger systems, set *Z* might contain zones of a power system or even countries. Note that the modeler usually decides on the spatial granularity based on the presence of common regulatory rules or pricing schemes in a zone or/and based on the congestion observed on transmission lines connecting adjacent regions. Finally, set *F* includes the different fuels used and we model it to keep track of the consumption of different fuels since for certain fuels domestic upper bounds on consumption might apply or/and issues of energy security might be involved in case of imported fuels. In addition, different types of fuels have different carbon content and lead to different emissions of carbon dioxide, which are important to track in case environmental policies exist.

OBJECTIVE FUNCTION

The objective function in this model minimizes the total system cost including violation/ penalty terms for constraints that are not met. All generation costs of the system are considered: (i) fixed costs including annualized capital cost payments for new generators[39] and fixed operation and maintenance costs, (ii) variable costs including the fuel costs and any variable operation and maintenance costs, (iii) cost to procure spinning reserves, (iv) carbon tax payments, and (v) penalties for unmet demand and unmet reserve requirements at the system or the zonal level.

LOAD APPROXIMATION

The model is usually employed to decide or explore optimal generation investment plans at the country or multi-country level. Thus, modeling all the 8,760 hours of a year does not seem a practical option. Moreover, the reader should bear in mind that we model future years for which we have forecasts on specific values for the power system such as energy consumption and highest amount of power demanded during the year (also known as peak power).

We use the forecasts provided along with historical detailed data on the chronological profiles of demand to generate future load time series. More details on the procedure followed to generate the projected load time series are provided in the section F.5. From the resulting load time series, a limited number of days, per quarter in the year, are selected to represent the hourly demand profile of a specific year. In the most recent iteration of the model we select three days per quarter in a year. The first day is the one (24 hours) that contains the maximum peak in the quarter. The second is the day that contains the minimum peak in the quarter. The third is the 24-hour day that contains the average per hour in the quarter. In total the load demand in a year is represented by 12 days (3 days x 4 quarters).

VALUE OF LOST LOAD

The Value of Lost Load (VoLL) is an exogenous assumption that significantly affects the total nonserved energy in the system and the investment decisions of peaking units. There is no universally acceptable VoLL and different

[39] Capital costs of existing generators are considered sunk costs and are not included in the objective function.

methods have been applied to estimate a reasonable value for the unserved energy. Typical values used in developed economies vary between US$4,000/MWh and US$40,000/MWh while in developing countries between US$1,000/MWh and US$10,000/MWh (Van Der Welle and Van Der Zwaan 2007). In addition, studies indicate that factors such as the timing of the interruption or the duration of a blackout might affect the VoLL (Van Der Welle and Van Der Zwaan 2007). "The intersection between the cost function of non-served energy and the cost function of the peaking technology determines the number of hours in a year for which it is cheaper to curtail demand rather than supply the full peak. If the maximum number of hours with non-served energy is fixed by the reliability criteria of choice, we can use the criterion to derive an analytical expression for the Value of Lost Load" (De Sisternes 2013):

$$VOLL = \frac{CapCost_{NG,y} * CRF_g + FOM_g}{HOURS\ (CRITERION)} + GenCost_{g,f,y} + carbon\_tax_y * carbon\ emission_f * HeatRate_{g,f}$$

"Alternatively, we can assume that some demand is sensitive to price, avoiding the price going above some certain threshold below the values presented above. In reality, this is achieved through contracts with special customer groups that are willing to reduce their demand during peak hours, or with grid elements that can supply electricity on an ad-hoc basis. Elements within this category are emergency generators located in critical infrastructures and public facilities such as hospitals, government, etc., used for back-up power in case of blackouts, staying idle when the system is operating normally. These generators could potentially be used to deliver electricity when prices are high, without jeopardizing their back-up generator functionality. Typically, back-up generators are fueled with expensive diesel, and if they are used in the mode just described, the system VOLL would take the value of the variable cost of these generators (~500 $/MWh)" (De Sisternes 2013).

TRANSMISSION NETWORK CONSTRAINTS

Kirchhoff's laws are physical laws governing the flows over transmission lines in a network. According to the first Kirchhoff law, also known as KCL (Kirchhoff's Current Law), the sum of injections in a node should equal zero. In our formulation, KCL corresponds to equation (9). There, we can see that the power provided by generators and storage should be equal to demand (minus the unmet demand) plus/min outflows/inflows from the node to adjacent nodes.

$$\sum_{g \in Z,f} gen_{g,f,q,d,t,y} - \sum_{z2} trans_{z,z2,q,d,t,y} + \sum_{z2} (1 - LossFactor_{z,z2,y}) * trans_{z2,z,q,d,t,y} + storage_{out_{z,q,d,t,y}} - storage_{inj_{z,q,d,t,y}} + unmetDem_{z,q,d,t,y} = Demand_{z,q,d,t,y} \quad (9)$$

Note that the second Kirchhoff Law (or widely known as KVL, Kirchhoff's Voltage Law) is valid for power systems but for reduced power systems, it might not apply depending on the method of network reduction followed. In this particular formulation, KVL is not considered.

Another important feature of our model relates to modeling of transmission losses. We model transmission losses as a percent reduction of the imported electricity at each node. In particular, term

$$\sum_{z2} (1 - LossFactor_{z,z2,y}) * trans_{z2,z,q,d,t,y}$$

at equation (9) models injections to node z and we can see how the loss factor reduces the amount of energy imported. On the contrary, the outflow is fully considered at the origin node of the network:

$$\sum_{z2} trans_{z,z2,q,d,t,y} .$$

Another common constraint for transmission networks refers to the capacity limits of transmission lines. In particular, as equation (10) implies, the flow over a specific line cannot exceed a certain limit, which is defined either by thermal limit of the line or upper bounds imposed by reliability considerations. Note that we model flows over a particular transmission line with two positive variables, one for each direction. Please observe that the transmission limit parameter might change per year to reflect planned upgrades or additions to the transmission network. Moreover, the transmission limit differs per season since ambient temperature affects the capacity available for power transfers.

$$trans_{z,z2,q,d,t,y} \leq TransLimit_{z,z2,q,y} \quad (10)$$

SYSTEM REQUIREMENTS

In our formulation, we model two products that the system operator might require generators to provide during operation: (i) energy and (ii) spinning reserves. As per the North American Electric Reliability Corporation's (NERC n.d.) definition, spinning reserves refers to "unloaded generation that is synchronized and ready to serve additional demand." Note that more products exist, especially in organized U.S. wholesale markets such as nonspinning reserves or flex ramp. Operating reserves (spinning and nonspinning reserves) provide the capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages, and local area protection (NERC n.d.). Moreover, under the spinning reserves different products might exist with respect to the response times required, etc.

The amount of spinning reserve required depends on several factors that the planner/operator considers such as the load level and the associated forecasting error, the forecasting error attached to the renewable generation, and the size of the largest unit committed on the system to be able to accommodate N-1 outages. Equation (12) indicates that spinning reserve can be provided by interconnections. On top of systemwide reserve requirements, zonal requirements apply to accommodate for outages on transmission lines connecting adjacent regions/zones/nodes.

$$\sum_{g} reserve_{g,q,d,t,y} + unmetSResSY_{q,d,t,y} \geq SResSY_{y} \quad (11)$$

$$\sum_{g \in Z} reserve_{g,q,d,t,y} + unmetSResZo_{z,q,d,t,y} + \sum_{z2} (TransLimit_{z2,z,q,y} - trans_{z2,z,q,d,t,y}) \geq SResZo_{z,y} \quad \forall z,q,d,t,y \quad (12)$$

Planners usually consider a planning reserve margin (PRM) to account for forecasting error in demand projections. Typical values for the PRM vary between 10–15 percent. Equation (13) indicates that interconnections can be accounted for as reserve margin. Note that intermittent units do not contribute towards the planning reserve constraint at their full capacity but at a fraction specified by the planner, for example, in the U.S. markets this fraction is calculated based on available historical data as the capacity factor during a set of peak hours (Hobbs and Bothwell 2016).[40]

$$\sum_{g \in Z} cap_{g,y} + unmetRes_{z,y} + \sum_{z2} \sum_{q} TransLimit_{z2,z,q,y} \geq (1 + PRM_{z}) * \max_{q,d,t} Demand_{z,q,d,t,y} \quad \forall z,y \quad (13)$$

GENERATION CONSTRAINTS

We decide to include spinning reserves since they will "consume" capacity that could be used for power generation.

$$\sum_{f} gen_{g,f,q,d,t,y} + reserve_{g,q,d,t,y} \leq (1 + OverLoadFactor_{g}) * cap_{g,y} \quad (14)$$

Equation (14) assures that the power generated by the unit along with the spinning reserves provided by the same unit do not exceed the unit's capacity.[41] Note that the capacity is augmented by an overload factor. This factor is typically 10 percent for those generators that can handle overload conditions for a short period of time, and zero for those generators that cannot handle such conditions.

Given that spinning reserve products are usually defined with respect to response time of generator to a certain dispatch signal, only a certain percentage of the generator's unit qualify as a reserve offer. We capture this characteristic in the model through equation (15).

$$reserve_{g,q,d,t,y} \leq cap_{g,y} * ResOffer_{g} \quad (15)$$

[40] For the first model runs, capacity credit was considered at full capacity. This will be modified in the next runs but it is not expected to change the model results significantly.
[41] Depending on the scope of the project, the dispatch constraint (14) might be slightly different. For example, the ReEDS model implemented by the National Renewable Energy Laboratory (NREL) (Short et al. 2011) treats quick start capacity service provided by a generator in the same way as spinning reserves under constraint (14) and on top of that, it accounts for planned and forced outages by considering average outage rates.

Ramping constraints acknowledge that the generation units have inertia in changing their outputs and differences in generation outputs between consecutive hours should be constrained by the ramping up and down capabilities of the unit.

$$\sum_f gen_{g,f,q,d,t-1,y} - \sum_f gen_{g,f,q,d,t,y} \leq cap_{g,y} * RampDn_g \quad \forall\, t > 1 \quad (16)$$

$$\sum_f gen_{g,f,q,d,t,y} - \sum_f gen_{g,f,q,d,t-1,y} \leq cap_{g,y} * RampUp_g \quad \forall\, t > 1 \quad (17)$$

Another important feature of generators is the minimum load. The minimum load can either be determined based on technical specifications provided by the manufacturer or be calculated as an "economic" minimum beyond which the unit can provide energy economically. The minimum load constraint is really important for unit commitment and requires the use of binaries variables that make sure the constraint is enforced when the unit is on. However, in the planning models operations are approximated through a simple dispatch model for representative hours of the year. In the same manner, an approximation of the minimum load constraint is applied for some thermal units the minimum load constraint is judged to be important. In this particular application, the modelers decided that the minimum load constraint is relevant only for a subset of the days modeled and the constraint is activated only for those days. Constraint (18) is forcing all units to generate power equal to at least their minimum loading levels for specific days in the year.

$$\sum_f gen_{g,f,q,d,t,y} \geq MinCapFac_g * cap_{g,y} \qquad \forall d \in M \quad (18)$$

Generating units require maintenance every year. Given that, we should consider the units as unavailable for certain periods during the year. In this particular application, we consider a uniform availability factor per quarter to account for maintenance.

$$\sum_{f,d,t} Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \leq Availability_{g,q} *$$

$$\sum_{d,t} Duration_{q,d,t,y} * cap_{g,y} \quad (19)$$

RENEWABLE GENERATION MODELING

Renewable generation differs from conventional units in that its output is, to a certain extent, uncontrollable and intermittent. The power generated by renewables such as wind or solar depends on wind velocity or solar irradiation. Collecting historical data that register weather information (such as wind speed, temperature, wind direction, etc.) or the power generation output by installed renewables at specific locations, analysts usually employ statistical methods such as k-means to reduce the amount of hours required to approximate the intermittent nature of renewables (Baringo and Conejo 2013). In this particular application, the generation profile for each renewable energy technology (such as wind or solar PV) is defined by the hourly capacity factor, in a year, of a generic power plant of each type, modeled at a specified location. Then, given this hourly profile for a year, we choose the amount of days modeled based on the days selected for the load approximation (see section F.4), that is, the renewable profile during the 12 days in the year selected, for load, is maintained.

$$gen_{g,f,q,d,t,y} \leq RPprofile_{g,RE,q,d,y,t} * cap_{g,y} \quad (20)$$

Note that the renewable profile is highly dependent on the region/location the resource is located. This formulation implicitly models that aspect since *g* might have different elements for the same generation technology at different locations.

CONCENTRATING SOLAR POWER (CSP) MODELING

CSP technology modeling differs from other renewable technologies due to the complexity derived by its storage capabilities. The CSP configuration considered in this model consists of two integrated subsystems: the thermal storage system and power cycle. Thermal storage is modeled using a simple energy balance approach that includes charging and discharging energy. The power cycle model provides a simple mechanism for modeling the conversion from the thermal energy output from the solar field, and thermal storage into electrical energy.

$$storageCSP_{g,z,q,d,t,y} \leq cap_{g,y} * CSP\_storage \quad \forall\, map(g, CSP) \quad (21)$$

Equation (21) indicate that at any time the CSP storage level cannot exceed its storage capability.

$$genCSP_{g,z,q,d,t,y} = RPprofile_{z,RE \in CSP,q,d,t} * cap_{g,y} * \frac{SolarMultipleCSP}{TurbineEfficiency_{CSP} * FieldEfficiency_{CSP}} \quad (22)$$

The power output of the solar panel is calculated by multiplying the nameplate capacity of the CSP power plant, the capacity factor of the system, and the solar multiple, then, dividing this by the turbine and solar field efficiencies (Equation (22)).

$$\sum_{f \in CSP} gen_{g,f,q,d,t,y} \leq cap_{g,y} \quad (23)$$

Equation (23) indicates that all the power output produced by CSP generators at any given zone, cannot exceed the nameplate capacity. Finally, Equations (24) and (25) detail the power balance formulations for the power cycle and thermal storage subsystems.

$$\sum_{f \in CSP} genCSP_{g,z,q,d,t,y} * FieldEfficiency_{CSP} - storageCSPinj_{g,z,q,d,t,y} + storageCSPout_{g,z,q,d,t,y} = \frac{gen_{g,f,q,d,t,y}}{TurbineEfficiency_{CSP}} \quad \forall\, g, z, q, d, t, y \quad (24)$$

$$storageCSP_{g,z,q,d,t,y} = storageCSP_{g,z,q,d,t-1,y} + storageCSPinj_{g,z,q,d,t,y} - storageCSPout_{g,z,q,d,t,y} \quad (25)$$

TIME CONSISTENCY OF POWER SYSTEM ADDITIONS AND RETIREMENTS

We use constraint (26) to track the capacity in consecutive years. In particular, generation capacity at year y equals capacity at previous year plus any investment minus any retirement at year y.

$$cap_{g \in EG,y} = cap_{EG,y-1} + build_{EG,y} - retire_{EG,y} \quad \forall\, ord(y) > 1 \quad (26)$$

Four more constraints are formulated to fix the capacity at prespecified levels in certain years.

- The first constraint states that the total capacity of a new generator equals the capacity of that new generator built the previous year plus the capacity to be built the current year:

$$cap_{g \in NG,y} = cap_{NG,y-1} + build_{NG,y} \quad \forall\, ord(y) > 1 \quad (27)$$

- The second constraint forces the capacity at the first year of the horizon to be equal to the known level:

$$cap_{g \in NG,y} = PlantCap_{EG} \qquad ord(y) = 1 \quad (28)$$

- Third constraint forces the capacity of planned and candidate units at zero for years preceding the commission year of the unit. In other words, this constraint takes into account construction times and makes sure that enough time is allowed for a unit to become operational.

$$cap_{g,y} = 0 \quad \forall\, (y, g){:}\ (ord(y) - 1) * StageDuration_y + StartYear < Commission\_year_g \quad (29)$$

- The fourth constraint forces the capacity of existing units at zero in case they exceeded their lifetime. Note that a similar constraint would apply for new units in case more than 20 years were modeled. Given that the lifetime of any new generator is at least 20 years, no new generator is foreseen to retire in the horizon we model.

$$cap_{g,y} = 0 \quad \forall\, (y, g \in EG){:}\ (ord(y) - 1) * StageDuration_y + StartYear > Retirement\_year_{EG} \quad (30)$$

STORAGE MODELING

Economically efficient storage in power systems has mainly been pumped hydro storage for a considerable amount of years. Nowadays, more storage technologies are being added on the power system. However, for the time being no investments in new storage technologies are considered. The existing pumped hydro storage units are aggregated at the zonal levels and represented as one unit with characteristics reflecting the ones provided by all units in the zone.

Storage is modeled differently compared to conventional units since it requires two more variables: (i) one to keep track of the storage level and (ii) one to model the charging of the unit. The generator output of conventional units corresponds to the output of the storage unit when it is discharged. Moreover, the chronological sequence of the time slices is important in order to make sure that the simulated operation is feasible, for example, we cannot discharge a storage unit if the charging of the unit has not preceded. Finally, storage of energy requires the conversion of electricity to another form of energy, for example, mechanical for flywheels or chemical for fuel cells and common batteries. The conversion of one form of energy to another involves losses that we should take into account in our models.

Three constraints are used to make sure that the operation of storage would be feasible taking into account the time sequence of load blocks. The time sequence in this particular application is relevant at the week level. As a result, we initialize the storage levels at the first hour of each week modeled and assume that zero storage level would be available at the beginning of one week because of storage operations during the previous week. Constraint (31) enforces this initialization:

$$storage_{z,q,d=1,t=1,y} = 0 \quad (31)$$

Then constraints (32) keeps track of the energy stored in the unit between consecutive hours of the same day: the energy stored in the unit at time slice t equals the energy stored in the unit at time slice t-1 plus any injection discounted by the efficiency minus any discharge at time t. Third, constraint (33) makes sure that the last time slice of the previous day plus any injection discounted by the efficiency minus any discharge at time t is equal to the energy stored in the unit at time slice t.[42]

$$storage_{z,q,d,t>1,y} = storage_{z,q,d,t-1,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d,t-1,y} - storage\ out_{z,q,d,t-1,y} \quad (32)$$

$$storage_{z,q,d,t=1,y} = storage_{z,q,d-1,t=241,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d-1,t=24,y} - storage\ out_{z,q,d-1,t=24,y} \quad (33)$$

Constraint (34) forces the storage unit to discharge all its energy during the day. Essentially, it assumes daily cycles for the storage units, where the unit is charged during off-peak hours and discharged during peak hours.

$$\sum_{t \in PT} storage\ out_{z,q,d,t,y} \leq Storage_{efficiency_{z,y}} * \sum_{t \in OPT} storage\_inj_{z,q,d,t,y} \quad (34)$$

Note that storage units can be charged or discharged at a rate, which cannot exceed a specific value. To model this behavior, we include constraints (35) and (36), respectively.

$$storage\ inj_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \quad (35)$$

$$storage\ out_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \quad (36)$$

Similarly, the energy stored in a storage unit cannot exceed its designed capability.

$$storage_{z,q,d,t,y} \leq Storage\ energy_{z,y} \quad (37)$$

Moreover, we include some constraints that represent the storage operations[43]:

First, the power provided by the storage unit at any time slice t should not exceed the energy stored at the unit at the beginning of the time slice t:

$$storage\ out_{z,q,d,t,y} \leq storage_{z,q,d,t,y} \quad (38)$$

Second, the energy stored in the unit cannot exceed a certain limit as indicated by constraint (37). In that case, the maximum amount of

[42] Note that the representation of storage in the model is a discrete approximation of the actual operation of storage. For example, in reality the storage level of a unit will change within an hour depending on the charging or the discharging.

[43] These constraints might be redundant, but the modelers decided to include them to make sure the storage operational schedule is feasible. However, if the model size challenges the computational power available to the planner, the planner might want to reconsider their (de)activation.

injection of power to the storage unit cannot exceed the energy differential between the storage level at the beginning of the period and the maximum amount of energy that can be stored in the unit:

$$storage\ inj_{z,q,d,t,y} \leq Storage\ energy_{z,y} - storage_{z,q,d,t,y} \quad (39)$$

INVESTMENT CONSTRAINTS

Planners consider several constraints when they decide on a generation investment plan. Common constraints refer to budget, land use, scheduling of new construction, and consumption of specific fuels for energy security considerations.

Constraint (40) usually reflects land use considerations, regulation that imposes an upper bound on capacity of specific technologies, or simply resource potential (for example, for wind there is a finite amount of locations where wind farms can provide the capacity factor modeled).

$$\sum_{y} build_{g\ \in NG\ ,y} \leq MaxNewCap_{NG} \quad (40)$$

Constraint (41) is usually employed to reflect practical limitations on construction and spread the construction of new units more uniformly over time. For example, it seems unrealistic that the whole system capacity can be built in one year.

$$build_{g\ \in NG\ ,y} \leq Annual\ built\ limit_{y} * WeightYear_{y} \quad (41)$$

Constraint (42) imposes an upper bound on fuel consumption. This upper bound might correspond to the fuel reserves a country might have at its disposal or the capacities of refinement units or importing units such as size of LNG terminals. Constraint (43) simply estimates the fuel consumption. Note that in case we want to reduce the number of variables in our model, we can get rid of the fuel variable since it is defined in terms of the generation variable.

$$fuel_{z,f,y} \leq MaxFuelOff_{f,y} \quad (42)$$

$$fuel_{z,f,y} = \sum_{g\ \in Z\ ,q,d,t} Duration_{q,d,t,y} * HeatRate_{g,f} * gen_{g,f,q,d,t,y} \quad (43)$$

Constraint (44) represents a budget constraint. It limits the capital expenses withdrawal to be lower than a prespecified amount. In this formulation, we assume that the MaxCapital parameter is similar to the maximum debt payments that a power system planner can do over the horizon.

$$\sum_{,g\ \in NG} ReturnRate_{y} * pweight_{y} * CRF_{NG} * CapCost_{NG,y} * cap_{g,y} \leq MaxCapital \quad (44)$$

An alternative constraint that addresses the same concern but relies on different information is expressed by constraint (49). In that case, the planner does not know the maximum amount of debt payments that the power plant owners might make but he has a good understanding of the maximum capital available to the system for investment. In that case, the sum of the overnight capital expenditure is not allowed to exceed this known budget.

$$\sum_{g\ \in NG,y} CapCost_{g,y} \leq MaxBudget \quad (49)$$

$$emissions\_Zo_{z,y} = \sum_{g\ \in Z,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y} \quad (45)$$

$$emissions\_Zo_{z,y} \leq Zo\_emission\_cap_{y,z} \quad (46)$$

$$emissions_{z,y} = \sum_{g\ ,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y} \quad (47)$$

$$emissions_{z,y} \leq Sy\_emission\_cap_{y} \quad (48)$$

Another policy mechanism related to carbon emissions is a carbon tax (less popular than the cap-and-trade system at present). We model the carbon tax as part of the objective function. Note that the carbon tax does not correspond to an actual cost for the society since it is a transfer payment for emitters to the government. It reflects an actual cost, though, only if it attempts to monetize the public health cost and the damage to the environment. However, it reflects an actual cost for the power system since generators would probably have to pay the tax to the government and that's why it is part of the objective function (8).

$$carboncost_{z,y} = \sum_{g \in Z,f,q,d,t} Duration_{q,d,t,y} * carbon_{tax_y} * HeatRate_{g,f} * \\ * carbon_{emission_f} * gen_{g,f,q,d,t,y} \quad (8)$$

LIMITATIONS OF THE MODEL

As any model, this model also has some limitations since it is an approximation of the real system. Two major limitations of the model are the following:

(i) Transmission network representation: We assume zero congestion within each zone modeled. Moreover, KVL is omitted and the expansion of transmission network is not part of the model.

(ii) The model is deterministic and no uncertainty with respect to assumed parameters, etc, is taken into account.

F.4. CUSTOMIZED CONFIGURATION OF THE MODEL

The model developed as part of this study is quite comprehensive, incorporating various constraints related to generation investments, operation of the power system, and policy. Depending on the scope of each study for which it is used, analysts can decide on the subset of constraints they would like to use for the intended analysis. Activation and deactivation of different sets of constraints is straightforward when "flags" are used. One flag can be associated with one or multiple constraints and depending on the value of the flag, the respective constraint might be included or excluded from the model formulation. Usually, when the flag has a positive value the constraint is included in the formulation but when the flag has a zero value, the constraint is not part of the formulation. In table 44, we list all the flags available to the analyst and explain the rationale for their use. Finally, in the last column of the table we report if the flag was active or not for the results provided as part of the study.

On top of the flags associated with constraints, we also include a flag that allows us to either load as input data test cases to test if the model behaves properly.

Please keep in mind that depending on the purpose of each study and the available data, different constraints might be identified as redundant. For example, in cases of limited knowledge of the transmission capabilities we might not be able to formulate constraint (10). Another example could be constraint (40) in cases where no limits on investment in certain technologies or regions apply.

F.5. PROJECTED DEMAND TIME SERIES

Planning models usually rely on an approximate representation of the demand through a discretized Load Duration Curve. The number or "steps" that a Load Duration Curve should have to efficiently allocate future capacity between different technologies and regions depends on a number of factors such as the number of candidate technologies in terms of different characteristics, the shape of the load curve, and the variability of intermittent resources. Number of "steps" or "representative hours" differs per study but it is usually around 10–30 discrete demand levels.

The objective of this study is the assessment of trade benefits that could be achieved through higher degree of coordination between 18 different countries. The number of the regions along with the importance of the best possible representation of the coincidence of net load conditions across the countries led us to the conclusion that a higher number of discrete demand levels would be required. So, the modeling team decided that four representative weeks with hourly granularity for load and renewable energy resources would be a good approximation of the conditions that the power system operators might face in practice.

Table 44. Constraints and Features of EPM

Flag	Constraints Associated	Rationale	Status for the Analysis
Mingen_constraints	(18)	Many planning models omit minimum load constraints since it is hard to approximate its binary nature with a linear constraint.	Inactive
Spinning_Reserve_constraints	(11), (12), (15)	High-level planning models might not consider spinning reserves because the relative comparison of generation units in terms of reserve costs is similar to the one based on energy costs and the approximate accuracy of the power forecast makes the consideration of reserves redundant. However, reserve consideration might be important if certain units cannot qualify as reserve providers or/and they have variable energy profiles.	Active
Planning_reserve_constraints	(13)	Margin reserves	Active
Ramp_constraints	(16), (17)	Ramp constraints are meaningful only when the time sequence of the time blocks is respected. Moreover, in case individual generation units are aggregated to form one aggregated unit, enforcement of the constraint might not be relevant because ramping capability will actually vary with the number of units that are online, and generating power.	Inactive
Fuel_constraints	(42)	Fuel constraints might not be relevant when access to high quantities of internationally traded fuels such as liquefied natural gas and oil is easy and facilities for fuel handling are bigger than the size of the fuel needs of the power system. Another reason that might render the fuel constraints redundant could be the enforcement of environmental policies. In that case, certain policies might implicitly require much lower fuel consumption than the consumption that would be possible based on capacity of fuel-handling facilities or available fuel reserves. Third, another set of constraints that might implicitly take into account fuel constraints is constraint (40). By limiting the capacity of new generators, an upper bound on consumption of certain fuels is implied.	Active
Capital_constraints	(44)	In economies where access to capital for power system investment financing is easy, constraint (44) might not be needed.	Inactive
CO_2path_constraints	(46)	Constraint (46) imposes CO_2 caps on zones of the system. Constraint (46) might be relevant in case different environmental targets/policies apply for the different zones, for example, when each zone is a different country or state. However, in case zones represent different buses of the power system of a region with single environmental targets, constraint (46) might not have a practical meaning.	Inactive
CO_2total_constraints	(48)	Constraint (48) represents a single environmental policy on carbon emissions, applicable for the whole system. Constraint (48) might not be relevant when the system consists of zones that correspond to countries with different environmental goals.	Inactive

Source: World Bank staff.
Note: CO_2 = carbon dioxide

Upon decision on granularity of load representation in the system, the modeling team faced two decisions: (i) we could rely on historical data to do a retrospective assessment of trade benefits that the region could have gained by coordinating their power systems more closely; or (ii) project the demand series in the future to estimate potential future benefits that region might gain by increasing the coordination of their power systems. We decided to follow the second approach since it might give more valuable insights to policy makers given that new challenges faced by the system will be taken into account and the higher value of those insights might compensate for the lower confidence associated with the projected load time series.

For all countries modeled, CESI has provided us with projections on future annual consumption and future peak power. For most of them, the projection was provided to CESI by the Arab Fund for Economic and Social Development.

Based on those input data, we followed a two-step procedure to estimate the 8,760-point series for future demand. First step aimed to estimate the future load duration curve and second step aimed to reorder the hourly load levels from the load duration curve to form a chronologically ordered load curve.

FUTURE LOAD DURATION CURVE ESTIMATION

Based on experience, modelers thought that an odd order polynomial described by the following formula: $a*(x+b)^k+c*x+d$ approximates the load duration curve with satisfying accuracy. Knowledge of four parameters is required to generate load data using this formula. To estimate the four different parameters, for a given order k each time, a system of four nonlinear equations is solved using Matlab. The four nonlinear equations are based on (i) projected peak power, (ii) projected minimum load, (iii) projected power at an interim hour, and (iv) projected energy.

Detailed description of the equations can be found below:

$$a * \left(\frac{1}{8760} + b\right)^k + c * \frac{1}{8760} + d = 1 \qquad (1.6a)$$

$$a * \left(\frac{h_{int}}{8760} + b\right)^k + c * \frac{h_{int}}{8760} + d = \frac{Power_{interim}}{Peak\ Power} \qquad (1.6b)$$

$$a * \left(\frac{8760}{8760} + b\right)^k + c * \frac{8760}{8760} + d = \frac{Power_{min}}{Peak\ Power} \qquad (1.6c)$$

$$a * \frac{\left(\frac{8760}{8760}+b\right)^{k+1}}{k+1} - a * \frac{(b)^{k+1}}{k+1} + c * \frac{1}{2} + d = \frac{Energy}{8760*Peak\ Power} \qquad (1.6d)$$

Different odd orders for the polynomial are tested from 5 to 17 and the algorithm chooses the odd order which has the lowest mean square error for the historical 8760-datapoints load duration curve.

As discussed earlier in this section, the Energy and Peak Power is available for all countries of the model. However, further assumptions are required for:

- The minimum and interim power for all countries.
- All four assumptions for the subregions we use to model Saudi Arabia because the projections provided apply to the whole system.

For the first requirement, we decided to project minimum power and interim power by keeping constant in the future the historical ratio of those quantities to energy. The interim hour selected was 1,000 (load sorted) hours of the year.

For most countries, historical data of hourly granularity were obtained from a feasibility study published in 2014 (CESI-Ramboll 2014). For nine countries, data are from 2010. Iraq's data are from 2009 and 2011 data are used for Algeria, Egypt, Oman, Qatar, and Tunisia. For three countries (Lebanon, West Bank and Gaza, Syria), limited historical information was available in the public domain and we describe in section F.5 approach followed to generate the synthetic historical time series.

For the second requirement, we assumed that the allocation of energy across the six zones used for Saudi Arabia will be in the future identical to the allocation observed in 2010. Moreover, we assumed that the ratio of the sum of the individual peaks of the system over the coincident peak will be constant at the 2010 levels for the future and then the relative relationship of the individual peaks between each other will remain the same. We describe the assumptions in mathematical form below:

$$\left.\frac{Energy_{SA,subsystem}}{Energy_{SA}}\right|_{FUTURE} = \left.\frac{Energy_{SA,subsystem}}{Energy_{SA}}\right|_{2010} \qquad (1.6e)$$

$$PeakSubsystem_{FUTURE} = \frac{PeakSubsystem_{2010}}{\Sigma_{SUBSYSTEMS} PeakSubsystem_{2010}} * \frac{\Sigma_{SUBSYSTEMS} PeakSubsystem_{2010}}{Peak_{system,2010}} * Peaksystem_{future} \qquad (1.6f)$$

REORDERING THE PROJECTED LOAD LEVELS TO FORM A CHRONOLOGICALLY ORDERED LOAD CURVE

For all systems included in the model, we have either actual or synthetic historical data. We assume that there is a one-to-one mapping between the order of an hour in the load duration curve (x) and the order of the hour in the chronological load curve (y=f(x)). Assuming that this one-to-one mapping will be valid in the future, we assign the load level corresponding to the x hour of the load duration curve to the f(x) hour of the future year.

Given that the weekly patterns of the chronological load curve are quite significant in most of the systems modeled (that is, load is significantly higher during workdays than the non-workdays), the "mapping" is slightly shifted. In case the first day of the future year is later in the week (assuming the first day is Sunday), we assign the first same-day in the historical year to the future year and shift the days from the first week of the historical year to the last week of the future year. The reverse assumption is followed when the future first day is an earlier day in the week.

It is important to note that the projections provided are in the local time zone and we shift the final loads selected by the week selector to a common time zone.

APPENDIX G. TRANSMISSION TECHNOLOGY AND COSTS

G.1. INCOMPATIBILITY OF NEIGHBORING SYSTEMS

Interconnection of power networks on the Arabian Peninsula is faced with complex issues relating to incompatible national power systems, damage by war, and political enmity. However, the successful operation of the Saudi GCC Grid in pioneering the use of high voltage direct current (HVDC) in its various forms to integrate 50 hertz (Hz) and 60 Hz high voltage alternating current (HVAC) power systems is a model for enabling economic trading of generation resources by neighboring countries. The continued deployment of both HVDC and 400 kilovolt (kV) HVAC transmission interconnections between Pan-Arab countries will facilitate staged restoration of power security in war-torn countries as well as providing technical advantages in managing the rapid growth of intermittent renewable power from solar and wind generation.

In this respect HVDC-HVAC terminals at each end of the HVDC line can provide stabilizing functions to enhance the security of the respective HVAC systems by enabling power to be switched on and off without the complications and delays involved in the procedures of re-synchronization of large neighboring power systems. Moreover, HVDC terminals can act like large batteries capable of mitigating intermittency of wind or solar generating plants. In this respect they can be used to earn additional revenue in a power market requiring ancillary services to maintain power system stability.

G.2. 400 KV HVAC TRANSMISSION LINES AND SUBSTATIONS

Preliminary cost estimates of 400 kV transmission lines and substations are based on data from regional projects that reflect the environmental conditions in the Pan-Arab region. The determination of HVAC transmission line “loadability” is a function of the voltage, conductor and bundling sizes, and the length of the line. For short 400 kV lines (that is, up to a 100 km) the most economic loadability will be about half the maximum thermal rating of the line—as determined by the aggregate bundled conductor cross-sectional area—typically about 1,200 MW. For longer 400 kV lines, the loadability is determined by the surge impedance loading (SIL) of the line—that is, about 500–700 MW as determined by tower structures and conductor spacings. For 400 kV lines longer than 400 km stability limits may determine the maximum allowable load that can be as low as 20 percent of the thermal rating.

Various consultants working in Arabia (Norconsult, PB Power, KEMA, and JICA [JERA-Nippon Koei]) have developed standard estimates of cost per kilometer for a typical double circuit 400 kV line, along with item cost rates for extra high voltage (EHV) switchgear, transformers, and reactive components. Their estimates are based on the designs already in use in Iraq (PB Power; figure 47, left) and Jordan (JICA; figure 47, center) and within the Saudi 50 Hz 400 kV GCC system. Figure 47 (right) shows a +-500 kV HVDC line in the United States.

G.3. HVDC INTERCONNECTIONS AND LINES

The use of HVDC technology is necessary to enable interconnection between neighboring asynchronous power systems. It is also possible a new type of technology using Variable Frequency Transformers (VFT) may be applicable in some

Figure 47. Transmission Line Towers

circumstances, especially when the power transfer levels are less than about 300 MW (CIGRE 2006). Thus, when a 50 Hz and a 60 Hz power system meet at a common border, an HVDC back-to-back (BtB) converter facility is necessary for power transfer from one side to the other. However, having been thus forced to invest in an HVAC-HVDC-HVAC facility, consideration should be given to the technical and economic advantages of using the HVDC transmission interconnection between two terminal HVAC-HVDC converters. In this respect the construction cost of a HVDC transmission line is typically about half the cost of an equivalent capacity double-circuit HVAC transmission line.

A typical 500–600 kV HVDC transmission line (as used in Saudi Arabia) comprises two circuits (one positive, one negative) together with a ground return circuit for use when any one circuit suffers line short circuits or insulation failure. When both HVDC circuits are in full operation there will be a potential difference of 1,200 kV between them and no current flows through the ground circuit. However, each circuit is capable of 50 percent of the rating using the ground return if the other circuit fails. The capability of the HVDC can be built in stages to match transfer requirement—for example, by operating initially in the monopole mode then later upgrading to the double pole mode with backup earth return.

G.4. ASSUMPTIONS FOR ECONOMIC STUDIES

The cost estimates provided herein should be considered as base costs that exclude land cost and physical contingencies due to uncertainties related to (i) substation foundations, (ii) terrain and foundations, (iii) contracting, (iv) financing, etc. HVAC lines are expected to be double circuit 400 kV towers built to standards well established in the region. HVDC lines will be expected to follow the practice used in the Saudi Arabian 600 kV line, technical details of which are not available at this time.

For estimating the investment costs of selected transmission interconnection projects discussed in this report, the following unit costs were used:

Table 45. Cost Summary of Transmission Equipment

Summary of Unit costs	Rating	Unit	Length	$Thous/unit
400 kV D/C lines	3*560mm SIL 600 MW n-1	km	>200 km	423
400 kV S/C lines	3*560mm SIL 600 MW n	km	>200 km	264
400 kV D/C lines	3*560mm SIL 400 MW n-1	km	>200 km	395
500 kV HVDC	Dbl cct Bipole	km		372
400 kV T/L Bay	1,000 MW CB, meters, bus	Bay		2,000
380 kV T/L Bay	400 MW CB, meters, bus	Bay		1,340
400 kV Reactor	CB, Fixed reactor	kVA		20
HVDC BtB	500 MVA Converter	MVA		0.336
HVDC Converter	500 MVA Converter	MVA		0.16
Transformer	CB, 400/161 kV	kVA		10.58
Auto Transformer	CB, 400/161 kV	kVA		8.46

Source: WBG 2019e
Note: BtB = back-to- back; CB = Circuit Breaker; D/C = Double Circuit; HVDC = high voltage direct current; km = kilometer; kV = kilovolt; kVA = kilo volt-ampere; mm = millimeter; MVA = Mega Volt-Ampere; MW = megawatt; S/C = Single Circuit; SIL = Surge impedance loading; T/L = Transmission Line.

These costs should be used in the economic analysis by applying at least a 15 percent physical and 10 percent price contingencies. For construction of a conventional 400 kV transmission a three-to-four year construction should be used with annual disbursement of 20 percent, 30 percent, 30 percent, 20 percent; likewise, for substations and HVDC: 10 percent, 50 percent, 30 percent, 10 percent.

APPENDIX H. TECHNICAL CHARACTERISTICS AND ESTIMATED PROJECT COST OF THE PROPOSED CROSS-BORDER TRANSMISSION LINES

H.1. SUMMARY TABLE OF TRANSMISSION OPTIONS

Summary of Pan Arab Power Trade Options (PTO) and Estimated Project Costs (EPC) for Selected Projects						
PTO #	Reinforced Interconnection	Technical Characteristics	Distance (km)	EPC US$M	Increased Capacity (MW)[/1/]	Commission Year
1	Algeria (Ghazaouet/Tlemcen) – Morocco (Oujda)	Existing HVAC OHTL 2*220kV and 2*400kV	0	$0.0	600	2025
2	Egypt (High Dam) – Sudan (Merow)	HVAC OHTL 500 kV plus 4 bays	730	$374.9	1,000	2025
3	Egypt (El Arish) – Gaza Strip	OHTL 200kV rated 950MVA	45	$250.0	175	2025
4	Egypt (Taba) – Jordan (Aqaba)	Second line 400kV, HVAC Submarine cable	13	$150.0	650	2022
5	Jordan (Amman West) – West Bank	(JDECO-4) HVAC OHTL 400 kV	40	$39.4	160	2025
6	Libya (Tobruk) – Egypt (Saloum – Sidi Krir PP)	500kV line from Sidi Krir to Saloum HVDC BtB, 400kV to Tobruk	616	$493.4	370	2025
7	Libya (Tobruk) – Egypt (Saloum)	HVDC BtB/Trafos Upgraded to 1000MW	616	$196.0	450	2030
8	Second circuit of Jordan (Amman North) – Syria (Dir Ali)	HVAC OHTL 400 kV plus two bays each end	105	$53.4	450	2025
9	Third circuit of Jordan (Amman North) – Syria (Dir Ali)				200	2030
10	Lebanon (Ksara) – Syria (Dimas)	HVAC OHTL 400 kV	42	$44.7	730	2024
11	Saudi Arabia – GCCIA Interconnection System	Third 600MVA BtB HVDC link 400 kV at Al-Fadhili	0	$0.0	600	2025
12	Kuwait – GCCIA Interconnection System	Third 650MVA Auto Trafo plus 4 L Trafo bays	0	$7.4	600	2025
13	Qatar – GCCIA Interconnection System	Existing 2*1900MVA 400kV connections	0	$18.0	1050	2025
14	UAE – GCCIA Interconnection System	Existing 2*1400MVA GCC Grid Lines	0	$0.0	900	2025
15	Bahrain – GCCIA Interconnection System	Existing 2*750MVA 400kV lines	0	$6.8	600	2025
PTO #	Proposed New Interconnection	Technical Characteristics	Distance (km)	EPC US$M	Capacity (MW)	Commission Year
16	Saudi Arabia (Medinah) – Egypt (Badr)	OHTL HVDC to Tabuk; 20km submarine cable over Gulf of Aqaba; HVAC OHTL 500kV to Badr City, Egypt in service 2024	1,500	$2,500.0	3,000	2023
17	Saudi Arabia (Jazan) – Yemen (Saana/Tiaz/Aden)	Jazan 380kV via HVDC BtB OHTL 400 kV	581	$482.6	500	2025
18	Tunisia (Bouchemma) – Libya (Melitia)	HVAC OHTL 400kV plus switchbays	250	$125.1	500	2023
19	Second Circuit of Tunisia (Bouchemma) – Libya (Melitia)				500	2027
20	Saudi Arabia (Qurayyat) – Jordan (Qatranah)	First Stage HVDC 3 Way Connect Saudi-Jordan-Iraq	165	$425.4	1,000	2027
21	Saudi Arabia (Hail) – Iraq (Karbala)	Hail to Rafha to Arar, Saudi, 380kV OHTL and HVDC Arar, Saudi to Karbala, Iraq	729	$683.8	1,000	2027
22	Jordan (Amman East) – Iraq (Qa'im) via Azraq NPS	Second Stage HVDC 3 Way Connect Saudi-Jordan-Iraq	523	$390.0	500	2025
23	Saudi Arabia (Ras Abu Gamys) – Oman (Ibri IPP)	HVDC line with Converters both ends	688	$633.5	1,000	2027
24	Kuwait (Subiyah) – Iraq (Basra)	AC Double circuit OHTL 400kV	122	$66.3	1,000	2027
25	Kuwait (Jahra) – Saudi Arabia (Qaisumah/Rafha)	380kV OHTL from Rafha to Qaisumah, Saudi; to 400kV HVDC BtB at border Saudi-Kuwait-Iraq	492	$611.8	1,000	2027

Note [/1/]: The capacity in MW corresponds to additional capacity for reinforcement projects and total capacity for new interconnection projects.

The WB modeling team investigated the power trading options based on the use of existing transmission links, transmission lines under construction or transmission interconnections planned for implementation before 2030. The table provides a cross reference to power trade options (PTO) estimated costs of the interconnection projects outlined in this report.

H.2. KSA-NORTHERN REGION PAN-ARAB COUNTRIES

Even though the Algerian interconnections with Morocco are well developed, two 220kV lines in operation in 1988 and one 400kV line in operation in 2010, their use for cross-border electricity trade has been limited to mutual aid and annual trade contracts. For the Algeria-Morocco project (PTO #1), the nominal capacity of existing cross-border interconnections between Morocco and Algeria allows the maximum transfer capacity to be increased from 400MW to 1000MW at no extra cost.

For the Egypt and KSA projects (PTOs #2 and #16), the costs are based on existing plans by the respective power companies. For the project #2, the proposed 500kV line between Aswan (Egypt) and Sudan is expected to reinforce supplies to existing 500/230kV substations en-route to Khartoum (Sudan): (i) at Wadi Halfa (Sudan), and (ii) Merow (Sudan), where two existing 500kV lines terminate, before going on to Kabushiya and Khartoum (Sudan). There are large hydro stations at Atbara and Merowe (Sudan) which would be used to complement power supplies to and from Aswan (Egypt). For the project #16, although it was proposed to build a HVDC line from Yanbu (KSA) to Aswan (Egypt), the option of continuing with an HVDC line from Aswan to Khartoum was not considered. The HVDC line that is under construction from Medinah (KSA) to Badr City (Egypt) was estimated in 2010 to cost $1.6 billion, but the current estimates to complete it are between $2.1 and 2.5 billion: https://www.utilities-me.com/news/13049-saudi-egypt-electric-grid-link-reaches-implementation-phase.

Information relating to Egypt-Gaza Project (PTO #3) is taken from a 2018 ESMAP report (https://www.esmap.org/node/158108) on the status of the existing link between Egypt and Gaza, which quotes, "Interconnection line between Egypt and Gaza is a 220 kV double circuit OHTL with 952 MVA thermal capacity in total and transfer is limited to 150 MW". This report indicates that a new backbone 220kV line would be needed throughout the length of Gaza to interconnect the

Figure 48. Coastal Interconnections

Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.

four main load centers and that an increase in power imports about 200km from Egypt to Gaza is contingent on upgrading the existing 220kV network throughout the Sinai region, as well as building a 40km 220kV line from Rafah (Egypt) to Jabalia (Gaza).

For the Egypt-Jordan project (PTO #4), the information was retrieved from the MED-TSO project (https://www.med-tso.com/publications/pub3/11_EYJO_Detailed_Project_Description.pdf). The PTO #4 consists of a second interconnection between Jordan and Egypt to be realized through a 13 km 400 kV, AC submarine cable. It is expected to increase the current transfer capacity between the two countries to reach 1100 MW, aiming to mitigate possible overloads in the path of the interconnection.

H.3. KSA-EGYPT MEDITERRANEAN COASTAL INTERCONNECTIONS

Power trade opportunities are proposed between Egypt and its Mediterranean neighbors Libya and Tunisia. In the western region of North Africa there are seven countries that plan to synchronously interconnect their power systems including: Algeria, Egypt, Libya, Morocco, Sudan, Tunisia, and Western Sahara. Morocco is connected to Spain and thus Algeria and Tunisia are now synchronized with the European high-voltage transmission network. Although Tunisia and Libya were interconnected in 2002, the link is currently not operational because of stability issues that are still under study. Moreover, it is likely that, because of the long distance involved, a HVDC or VFT interconnection will be required at one or more locations to separate the Egyptian based 50Hz region from the Moroccan based 50Hz region.

The Egyptian system will be linked to KSA via the multi-terminal ±500kV HVDC project capable of two-way 3000 MW power trading via 1250 km of DC line and 16 km of HVDC cable under the Gulf of Aqaba. The HVDC line terminates at two 1500MW converters in Badr City in Egypt and via a 750MW intermediate converter at Tabuk in KSA, and at a two 1500MW converters at El-Madinah and El Munawara in KSA. Two transition/switching stations (Nabq in Egypt and one on the eastern shore of the Gulf of Aqaba in KSA) will also be constructed for connecting the overhead lines and subsea cable. Other key projects in planning include the 30-km-long, 500 kV Giza North power interconnection; the 28-km-long, 500 kV Samallout–Suez Gulf–Jebel al-Zayt interconnection; and the 500-km-long, 500

Project EM#1a: Saloum 500kV S/S - Tubruk 400 S/S (built in two stages 500MW)								
Terminal and Intermediate Substaions				Estimated route km			Rate	Total
From	To	via	MVA/Cct	Egypt	Libya	Total	$Thous/km	US$M
Sidi Krir PP HVDC Term	Marsa Matruh HVDC Term	Egypt	1000	273		273	$372	$101.56
Marsa Matruh HVDC Term	Tobruk HVDC Term	Egypt/Libya	1000	223	120	343	$372	$127.60
Marsa Matruh HVDC Term	Marsa Matyru 220kV SS	Egypt	500	28		28	$250	$7.00
	Subtotal Transmission	HVDC	1000	496	120	616	$444	$236.15
Sidi Krir PP HVDC Term	Converter (2*500MVA)	500MVA	1000	2		2	$0.160	$160.00
Marsa Matruh HVDC Term	Converter (500MVA)		500		1	1	$0.160	$80.00
Marsa Matyru 220kV SS	2 220kV bays		500	2			$1,100	$2.20
Tobruk HVDC Term	Converter (2*500MVA)		1000		2	2	$0.160	$160.00
Total Route Jordan-Palestine Bilateral Connection								$638.35

Project EM#1: Saloum 500kV S/S - Tubruk 400 S/S with HVDC BtB at Saloum								
Terminal and Intermediate Substaions				Estimated route km			Rate	Total
From	To	via	MVA/Cct	Egypt	Libya	Total	$Thous/km	US$M
Sidi Krir PP 500kV	Saloum HVDC btB		1000	466		466	$444	$206.97
Saloum HVDC btB	Tobruk 400kV		1000		150	150	$423	$63.45
HVDC BtB SS	4*500MVA converters		1000			2	$0.336	$336.00
Sidi Krir PP 500kV	2*500kV bays					2	$2,000	$4.00
Existing Saloum 220kV SS	2*500kV bays					2	$2,000	$4.00
Tobruk 400kV	2*400kV bays					2	$2,000	$4.00
Soloum 400/220kV trafo	100MVA trafo and 440/220kV bays					2	$4,158	$8.32
								$626.74

Project EM#2: Militah, Libiya 400kV S/S - Bouchemma, Tunisia 400 S/S									
Terminal and Intermediate Substaions			MVA/Cct	Estimated route km			Rate	Total
From	To	via		Libya	Tunisia	Total	$Thous/km	US$M
Meltah 400kV susbstation	Bouchema 400kV	Coast	1000	75	175	250	$423	$105.75
Meltah 400kV susbstation	2*400kV bays					2	$2,000	$4.00
Bouchema 400kV	2*400kV bays					2	$2,000	$4.00
								$113.75

Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.

kV Sidi Krir–El Salloum transmission line including a new 500kV interconnection with Libya in order to upgrade the existing 230kV interconnection with the Arab Maghreb countries.

The estimated cost of providing a 1000MW connection between Egypt and Libya (PTO #6 and #7) is based on the EETC proposal to build a 500kV line from the 750 MW Sidi Krir Combined Cycle Power plant switchyard inland following the inland road parallel to the 220kV line along the coast. Because of the difficulties in synchronizing with the western states, it is assumed that this project will include a 100MW HVDC BtB station built at El-Salloum (Egypt) to interconnect with a 400kV line connected to Tobruk (Libya). An alternative project could be based on the use of a HVDC connection all the way to Tobruk with an intermediate terminal at Marsa Matru (Egypt) as the need arises to supply the local 220kV system. With the intermediate station, the costs would be comparable with the 500kB BtB solution.

The 400 kV and 220 kV transmission lines in Libya connect the main centers of Tripoli and Benghazi regions with loop designed transmission networks. The project to upgrade the existing 220kV line to El-Salloum will form part of the ELTAM transmission interconnector which connects the power markets of Egypt, Libya, Tunisia, Algeria and Mali. It will involve the reinforcement of the Libya part of the 210 km / 400 kV Libya to Tunisia (PTO #18 and #19) section from Abou Kamach (Libya) to the Tunisia border.

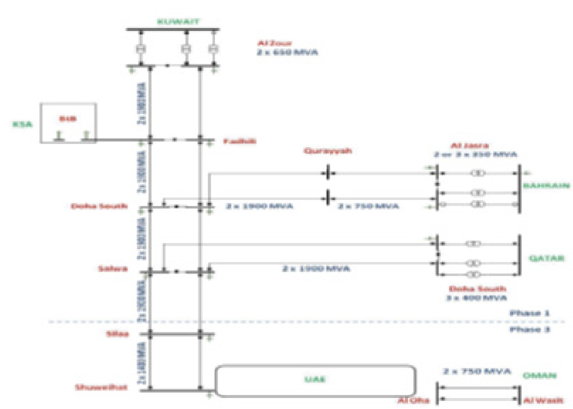
H.4. INCREASING GCCIA POWER TRADE CAPABILITY

The GCC interconnection (PTO #11 – #15) comprises seven 400 kV substations connecting five countries through approximately 900 km 400 kV OHTL double circuit backbone line rated at 1900 MVA connecting the substations of Al-Zour (Kuwait) in the North to the substation of Silaa (UAE) in the South. Bahrain is connected to the 400 kV backbone through two

Geographical structure of the GCCIA system

Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.

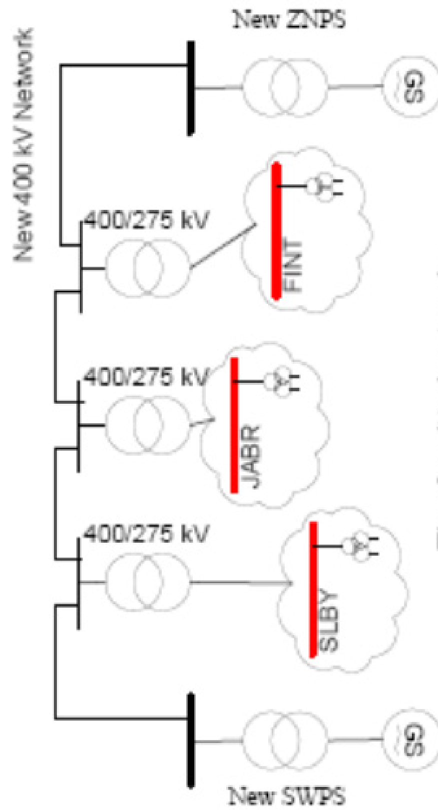
Topological structure of the GCCIA system



submarine cables rated each at 715 MVA. Kuwait, Bahrain and Qatar interconnect to the GCCIA system through, respectively, 3x650 MVA, 3x325 MVA and 3x400 MVA transformers. Saudi Arabia is connected through BtB HVDC converters rated at 3x600 MW at the 400 kV substation of Al-Fadhili. The HVDC station, in addition to being designed for economic power exchanges, also enables Dynamic Reserve Power Sharing (DRPS) between the 60 Hz and 50 Hz systems that has been to date activated on several occasions following severe active power imbalances for mutual support between the 50 Hz and the 60 Hz systems.

Kuwait's transmission network is connected with that of Saudi Arabia's via a 900km-long double-circuit 400 kV AC line through the Gulf Cooperation Council (GCC) interconnection project at Al-Fadhili. Kuwait is currently connected to the GCC grid at the Al Zour 400kV substation via three 275kV lines feeding back to the main load centers as shown on the diagram on the next page. However, Kuwait is reportedly building a new 400kV ring through the city area with three substations in Sulaibiya, Fintas, and Jabriya, all of which are rated 275/400kV as shown in the picture on the right-hand side below. A logical point for KSA to connect to this ring would be in the center of the ring at JBAR substation located near the Sulaibiya, Al-Jahra.

For PTOs #21, #24 and #25, the proposal for KSA to increase its renewable exports from Hail/ Rafha/ Qaisumah directly to Kuwait could be achieved by extending KSA's 380kV lines from Rafha to Qaisumah and thence to a proposed HVDC BtB facility at the location where the three borders (KSA, Iraq, and Kuwait) meet. The associated 400kV substation would provide a supply to a 400kV line to the new 400/275KV Sulaibiya substation enabling KSA power to be evacuated directly to



The proposed power system

the city or to north and south through the new 400kV grid. Although the project could also be used to facilitate a 400kV line to be built from the BtB facility to Nasirayah in Iraq, this is not included in the cost estimate below.

GCC interactions with Oman are in effect wheeled through the UAE 400kV transmission network and across the border from Sweihan (UAE) to Mahda in northern Oman. The existing Oman 220kV transmission system extends across the whole of northern Oman and interconnects bulk consumers and generators of electricity.

Project EM#5: Kuwait (Jahra) to HVDC BtB at Bdr ISAK– 380kV to Saudi Arabia (Qaisumah/Rafna)								
Terminal and Intermediate Substaions				Estimated route km			Rate	Total
From	To	via	MVA/Cct	KSA	Kuwait	Total	$Thous/km	US$M
Rafha PP	Qaisumah PP	KSA	1000	278		278	$423	$117.59
Qaisumah PP	Border HVDC BtB/400kV	KSA	1000	99		99	$423	$41.88
Border HVDC BtB/400kV	Jahra 400kV Kuwait	Kuwait	1000		115	115	$423	$48.65
	Subtotal Transmission	HVDC	1000	377	115	492	$444	$208.12
Rafha PP	2*380kV bays		1000	2		2	$1,340	$2.68
Qaisumah PP	4*380kV bays		1000	4		4	$1,340	$5.36
Jahra 400kV Kuwait	2400kV bays		1000	2			$2,000	$4.00
Border HVDC BtB/400kV	2*500MW HVDC BtB-(380/400kV)		1000		2	2	$0.336	$336.00
Total Route Jordan-Palestine Bilateral Connection								$556.16

KUWAIT

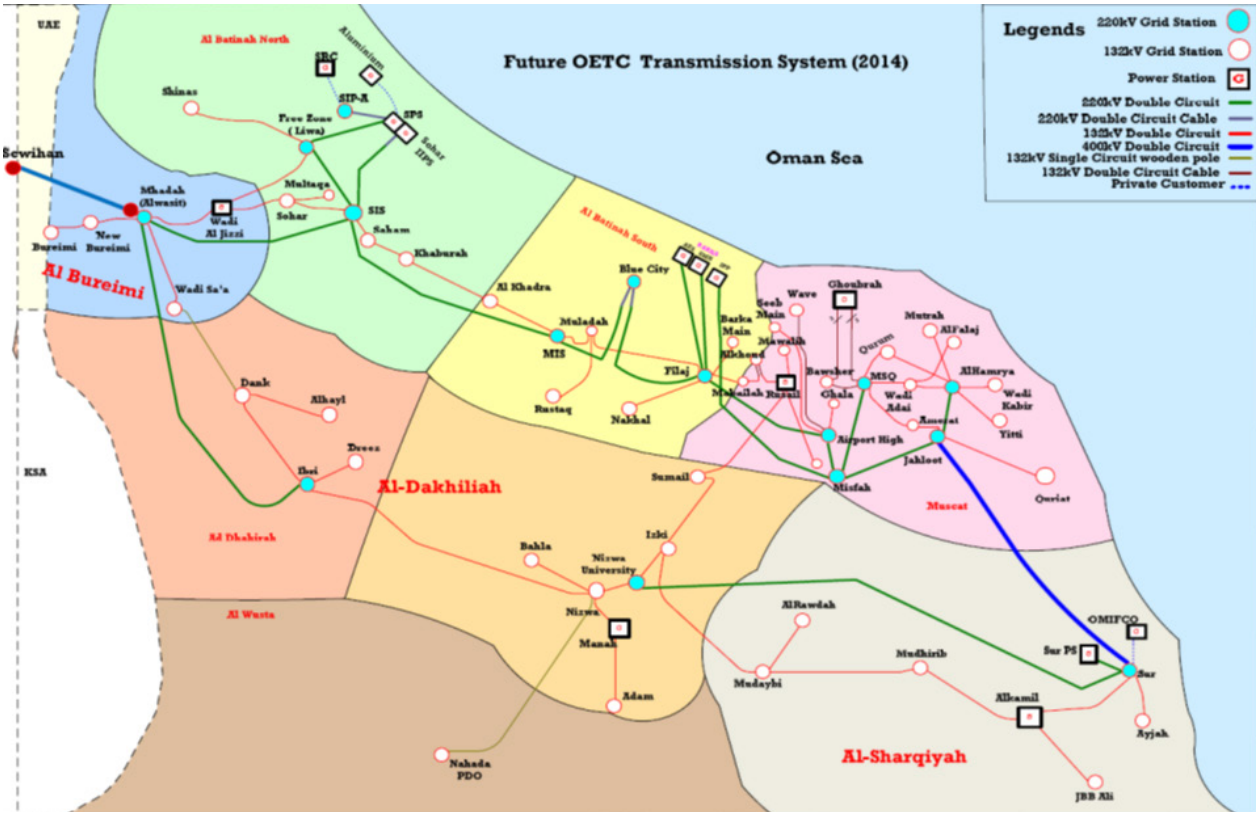
Note: All maps in this document are for illustration purposes of cross-border projects only and not intended to reflect any political boundaries.

Currently the Ibri independent power project (IPP) is a 1,509MW gas-fired power plant being developed in the Ad-Dhahirah region of northern Oman. The project includes the construction of a 400/220kV grid station to facilitate the transmission of power generated by the Ibri power plant to the national grid. The grid station will include three 500MVA transformers (400/220kV), 19 400kV gas-insulated switchgears (GIS), ten 220kV GIS, and two 4.3km-long LILO of 220kV Ibri – Mahdah overhead line.

It is difficult to get up-to-date connection details of the GCC interconnections with the member countries. While it is possible that more 400/230kV transformers could be added to the designated off-taking substations, the respective power companies would probably look for more diversification – e.g., by extending the 400kV lines to other substations in their domestic systems. The way in which they decide to evacuate the power within their system is beyond the scope of this type of cost estimation. As KSA and its Pan-Arab neighbors are increasingly intertwined with transmission interconnections, a more complex situation will arise requiring extensive load flow studies to determine the impact on adjacent transmission lines.

For PTO #23, by injecting power into the GCC 400kV backbone at its ends (Kuwait and Oman), KSA should be able to inject/wheel more power through Al-Fadhili. The extent to which this can be done can only be determined by load flow calculations that are beyond the scope of this analysis. If KSA injects more power at Al-Fadhili, GCC would probably have to build another 400kV line in parallel with the existing one.

Oman Transmission System in 2014 (with GCC 400kV interconnection)



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