Optimized Integration of Renewable Energy Technologies into Egypt's Power Plant Portfolio

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by

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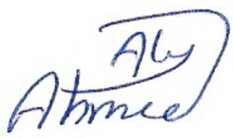
Eidesstattliche Erklärung

Hiermit erkläre ich, dass ich die vorliegende Arbeit selbständig sowie ohne unerlaubte fremde Hilfe und ausschließlich unter Verwendung der aufgeführten Quelle und Hilfsmittel angefertigt habe.

Stuttgart, 22. Dezember 2014



Ahmed Aly

*To the **One** who blossomed light into my heart*
*to find my way **Home***

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Thank you all ...

Abstract

In developed world, the three main criteria that characterize the energy supply of the future are: sustainability, security, and competitiveness. Hence expanding the share of renewables into the energy mix is highly regarded. Recently, some developing countries realized their potential for generating electricity from renewables, yet still have concerns regarding reliability and economic feasibility of such unconventional technologies.

Throughout this study, the electricity sector of the Arab Republic of Egypt has been analysed, the most promising location of technology-specific renewable energy technologies has been identified, and a capacity expansion master plan (with planning horizon until 2032) has been suggested in order to optimally integrate renewables into Egypt's existing power plant portfolio.

In the core of the followed methodology comes the capacity expansion and unit commitment optimization model REMix-CEM that has been developed by the German Aerospace Center (DLR) in order to support MENA countries in integrating renewables efficiently into their current fossil-fuel dominated power systems. REMix-CEM optimizes the capacity expansion of conventional and renewable technologies through minimizing the total generation cost of the entire system while maintaining continuity of supply.

The study concluded that nuclear option and introducing imported coal to Egypt's fossil fuel portfolio are both economically unfavourable. The capital cost of Concentrated Solar Power (CSP) technology need to be reduced to foster its earlier integration. One of the most remarkable findings is that not integrating further renewable energy technologies will lead to higher average system cost in the future.

Contents

List of Abbreviations

BUS	Backup System
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine Power Plant
CSP	Concentrating Solar Power
DLR	German Aerospace Centre
DNI	Direct Normal Irradiation
EEA	Egyptian Electricity Authority
EETC	Egyptian Electricity Transmission Company
ESMAP	Energy Sector Management Assistance Program
FLH	Full Load Hours
GAMS	General Algebraic Modelling System
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiation
GIS	Geographic Information System
GT	Open-cycle Gas Turbine Power Plant
HFO	Heavy Fuel Oil
HS	Hot Spot
HVDC	High Voltage Direct Current
INSEL	Integrated Simulation Environment Language
ISCC	Integrated Solar Combined Cycle Power Plant
LCOE	Levelized Cost of Electricity

LEAP	Long-range Energy Alternatives Planning System
LFO	Light Fuel Oil
MENA	Middle East and North Africa
MILP	Mixed Integer Linear Programming
NREA	New and Renewable Energy Authority
OPEX	Operational Expenditure
PB	Power Block
PV	Photovoltaics
RE	Renewable Energy
REMix-CEM	Renewable Energy Mix - Capacity Expansion Model
SEI	Stockholm Environment Institute
SF	Solar Field
SIL	Surge Impedance Loading
SM	Solar Multiple
SOLEMI	Solar Energy Mining
ST	Steam Turbine Power Plant
TES	Thermal Energy Storage System
WACC	Weighted Average Cost of Capital

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1 Introduction

As the first chapter of the thesis, the introduction chapter starts with brief background, followed by the motivation behind conducting this research. The research question and purpose are also tackled through this chapter.

1.1 Background

For the most of human history, our energy needs were modest. Our ancestors relied mostly on the sun, it was their source of light and heat. The horses' muscle and the wind power in our sails were their means of transportation. Animals were used to do jobs that they cannot do, and they used wind and water to drive simple machines to pump water and grind grain. This was the case until very recently on the planet earth's calendar when the industrial revolution emerged.

With the industrial revolution, came the evolution of the steam engine during the 17^{th} and 18^{th} centuries when a single steam engine, fired by coal, was capable of doing the work of dozens of horses. By the late 1800s, a new form of fossil fuel was emerging: petroleum. By the turn of the century, oil -processed into gasoline- was firing internal combustion engines. This opened the door for the massive development of automotive industry. Since then the modern society's life style has been dependent upon massive energy use, thanks to the low-cost automobile and the spread of electricity. Consequently, power plants became larger and larger, and transmission lines extended hundreds of kilometres. After the use of the nuclear power during the Second World War, the idea of using nuclear power for electricity generation had come true. The oil crisis of 1970s was the triggering moment behind the real research and development on renewable energies.

It is important to realize that on planet Earth there are three intrinsic energy sources: the sun, the planetary motion, and the geothermal energy. All energy resources on Earth are originated from one of the aforementioned energy sources. It is worth mentioning that the energy resources with renewable energy fluxes (the so called renewable energy) have lower energy density compared to the energy reserves (the so called fossil fuels).

It is interesting to mention that the first solar thermal power plant has been built in Maadi, Egypt back in 1913, designed by Frank Shuman. The first solar thermal power plant used parabolic trough solar field to power ca. 50 kW engine which was used to pump ca. 22,000 litres/minutes of water from the Nile River to adjacent cotton fields. Frank Shuman was a U.S. inventor who invented a demonstration solar engine in 1897 which made use of the reflected solar energy onto square boxes filled with ether working fluid to power a steam engine. In 1916 the media quoted Shuman promoting the utilization of solar energy, as he said We have proved the commercial profit of sun power in the tropics and have more particularly proved that after our stores of oil and coal are exhausted the human race can receive unlimited power from the rays of the sun Frank Shuman, New York Times, July 2, 1916.

1.2 Research Motivation

The power plant portfolio of Egypt is dominated by fossil fuel fired plants. Currently more than 90% of the generated electricity generated is from fossil fuel fired plants, the fossil fuel consumption increased from 23.6 Mtoe in 2008 to about 30 Mtoe in 2012. Although Egypt possess oil and gas fields, its production does not grow proportionally to cover its ever increasing consumption (see figure 1.1 and figure 1.2).

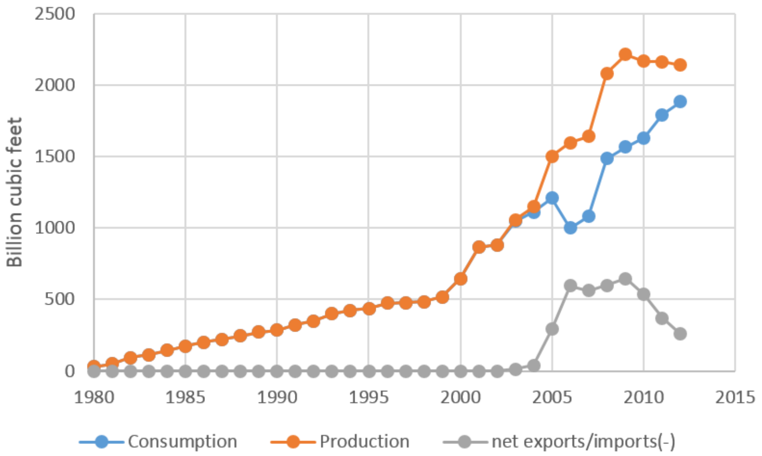

Figure 1.1: Production and consumption of natural gas in Egypt
Source: U.S. Energy Information Administration [5]

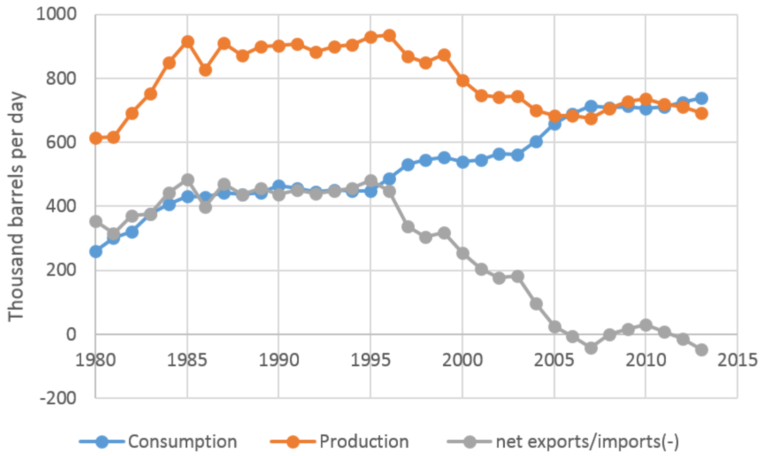

Figure 1.2: Production and consumption of fuel oil in Egypt
Source: U.S. Energy Information Administration [5]

It is worth mentioning that natural gas represented more than 84% of the total amount of the fuel used in 2012, and during the summer months the natural gas amount directed to the power generation sector is not sufficient to cover the electricity demand, so Egypt usually imports fuel oil and diesel to cover the natural gas shortage. To make matters worse, during the last four years, Egypt's gas production has been declining while its demand grows with an annual rate of 10%, this means that shortly Egypt would not be able to export gas anymore and it will have no other option than importing expensive gas from abroad.

The key motivation behind this study is to assess the role of renewable energy technologies in securing sustainable electric supply for Egypt which is characterized by achieving least totals system cost while ensuring reliable system design.

1.3 Research Question and Purpose

The key research question is: **How can Egypt optimally integrate RE technologies into its existing power plant portfolio?**

The answer of this key question involves the investigation of the below sub-questions:

- What are the available RE sources in Egypt? (i.e. where is its outstanding potential?)
- What are the economic consideration of each RE technology in Egypt? (i.e. what is the optimum capacity to integrate of each RE technology and when to integrate each plant to avoid significant tariff increase?)
- How to integrate RE in the power plant portfolio without compromising the minimum required firm power generation capacity?
- Where to integrate the new RE plants to minimize the additional required investment in the transmission network to link the supply with the demand?

So the objective of this research is to reach a clear plan (starting from the power system of 2012, with planning horizon of 20 years until year 2032) which identify recommended power generation capacity (both conventional and renewable) that should be added throughout this time span to ensure the security of supply, besides the integration of the economically feasible capacity of RE.

In general, there is an obvious lack of the strategic planning in Egypt (especially during the last 4 years, due to the severe political turmoil) and the strategic energy planning is not an exception. As a direct consequence -in recent years- most of the residential buildings in Egypt are facing frequent (daily) blackouts as the available power generation capacity could not cover the steadily increasing demand. Another reason for the frequent blackouts is that the government cannot provide all the required amount of the -heavily subsidized- fossil fuel to run the power plants. So, the recent governments have realized that the energy subsides have to be reduced (as the state will no longer be economically capable of maintaining such massive fossil fuel subsides).

1.4 Thesis Outline

This MSc thesis consists of five chapters, starting with Introduction chapter and ends with Conclusions chapter.

The introduction chapter starts with brief background, followed by the motivation behind conducting this research. The research question and purpose are also tackled in this chapter.

The Literature Review chapter gives an overview of the Egyptian electricity sector, and discuss the official future power system expansion plans. A relevant study conducted by Egyptian-German Joint Committee on Renewable Energy, Energy Efficiency and Environmental Protection (JCEE) has been also investigated.

The Methodology chapter describes the scientific methodology followed during the research. This chapter is divided into two main topics; the identification of the renewable energies technology-specific hot spots and the use of the REMix-CEM Optimization Model.

The Results and Discussion chapter elaborates on the different investigated scenarios and their considered assumptions. The detailed results of the two most important scenarios would be discussed thoroughly, besides a reflection upon all the five investigated scenarios.

Finally, the research conclusions and future recommendations are presented in the Conclusions chapter.

2 Literature Review

This chapter gives an overview of the Egyptian electricity sector, and discuss the official future power system expansion plans. A relevant study conducted by Egyptian-German Joint Committee on Renewable Energy, Energy Efficiency and Environmental Protection (JCEE) has been investigated as well.

2.1 Overview of the Electricity Sector

2.1.1 Electricity sector structure

The Egyptian Electricity Authority (EEA) was founded in 1976 as public monopoly that has the exclusive right to generate, transmit, and distribute electric power throughout Egypt [13]. In 1983, a new authority called Public Sector Authority for Electric Power Distribution was established under the direct jurisdiction of the Ministry of Electricity and Energy (MOEE) to handle electric power distribution [13]. The monopoly of the power generation by EEA ended in 1984, and energy purchase contracts with private operators was allowed. In 1986, the New and Renewable Energy Authority (NREA) was established to introduce renewable energy technologies to Egypt on a commercial scale, and it was entrusted to plan and implement renewable energy programs and projects in cooperation with other concerned national and international entities [3].

In 1996, the law was modified to allow the private sector to Build, Own, Operate, and Transfer (BOOT) electricity generation plants. Through

BOOT contract the private developer sells the electricity to the EEA for twenty years and then -by the end of the contract period- the private developer transfers the plant's assets to EEA. In 1998, the law was modified again and EEA's seven geographic generation zones were vertically merged with the eight distribution companies for creating seven companies responsible for both generation and distribution. At this point, the EEA was still directly responsible for transmission, dispatching, and planning of new generation and transmission projects, besides purchasing the electricity generated by the BOOT projects and sometime purchasing electricity from industrial plants' self-generation units - known as Independent Power Producers (IPPs).

In 2000, a new law was issued to change the Egyptian Electricity Authority (EEA) into an Egyptian joint stock (holding) company under the name of the Egyptian Electricity Holding Company (EEHC). Since 2001, a series of restructuring reforms took place aiming for unbundling of the generation, transmission and distribution activities. Now EEHC manage sixteen affiliated companies, six production companies, nine distribution companies, and the Egyptian Electricity Transmission Company (EETC) as shown in figure 2.1. It is clear that Egypt's electricity market is a single-buyer captive market. The government (represented by EEHC) holds a near-monopoly over generation, transmission and distribution. The EETC acts as the single electricity buyer and consequently the electricity prices for all sectors are determined by the government [23].

Table 2.1 shows the latest statistics by the EEHC disclosed in the 2011/2012 annual report [2]. It is worth mentioning that the power purchased from industrial self-generation plants (IPPs) represented less than 0.02% of the total generated electricity in 2012. There was 238 MW installed capacity of isolated power plants (represents 0.82% of the total installed capacity in 2012) which are located in remote areas and connected to the distribution networks of such areas. The 34 isolated power plants are mostly diesel engines and gas turbines, in addition to only one 5 MW Wind farm in Hurghada. The net energy generated from

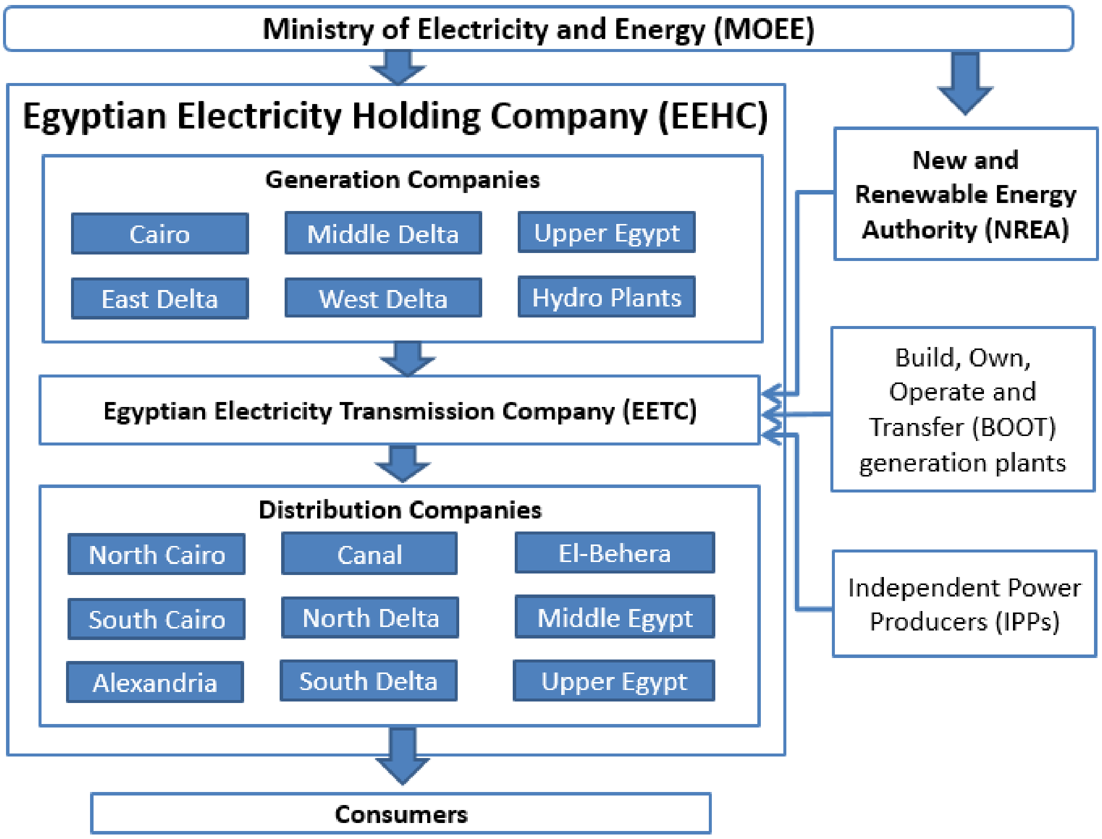

Figure 2.1: Egypt's electricity sector structure

all the isolated power plants reached about 220 GWh, which represented about 0.14% of the total generated electricity in 2012.

2.1.2 Electricity generation

During the last three decades the electricity consumption in Egypt has been increased drastically, hence the electricity generation has been increased from about 20 TWh in 1980 to about 150 TWh in 2011 (see figure 2.2), and during the same period the total installed capacity has been increased from 5 GW to 28 GW (see figure 2.3). Fossil fuel fired plants (i.e. conventional thermal plants) dominates Egypt's power plant portfolio, figure 2.4 shows the installed capacity's percentage of each technology.

Currently more than 90% of the generated electricity is from fossil fuel fired plants, the fossil fuel consumption increased from 23.6 Mtoe in 2008

Table 2.1: Overview of the latest statistics by the EEHC
Data source: EEHC 2011/2012 annual report [2]

Description	**Value** (in 2012)	**Compared to previous year**
Total installed capacity	**29 GW**	Increased by 7.5%
Peak load	**25.7 GW**	Increased by 9.5 %
Generated electricity	**157 TWh**	Increased by 7.2 %
Net electricity exchange with interconnected countries	**1.6 TWh**	Increased by 9.2 %
Total fuel consumption Heavy Fuel Oil (HFO) consumption Light Fuel Oil (LFO) consumption Special LFO consumption Natural Gas (NG) consumption Natural Gas ratio to total used fuel	**29,728 ktoe** **4,605 ktons** **4.5 ktons** **59.2 ktons** **29.2 billion m^3** **84.3%**	Increased by 8.4 % Decreased by 13.1 % Increased by 6.1 % Decreased by 27.5 % Increased by 12.8 % Increased by 4.9 %
Transmission lines and cables	**43.6 thousand km**	Increased by 3.3 %
Distribution MV and LV lines and cables	**405 thousand km**	Increased by 2 %
Average efficiency of thermal power plants	**42%**	
Average availability of power plants	**85 %**	

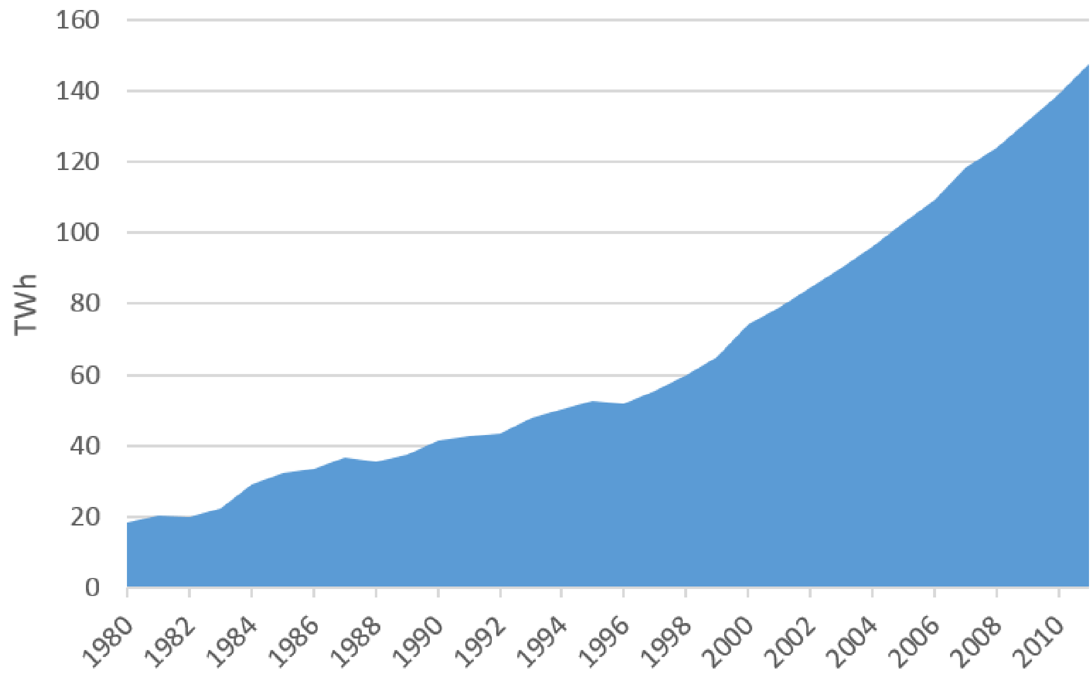

Figure 2.2: Development of electricity net generation
Data source: U.S. Energy Information Administration [5]

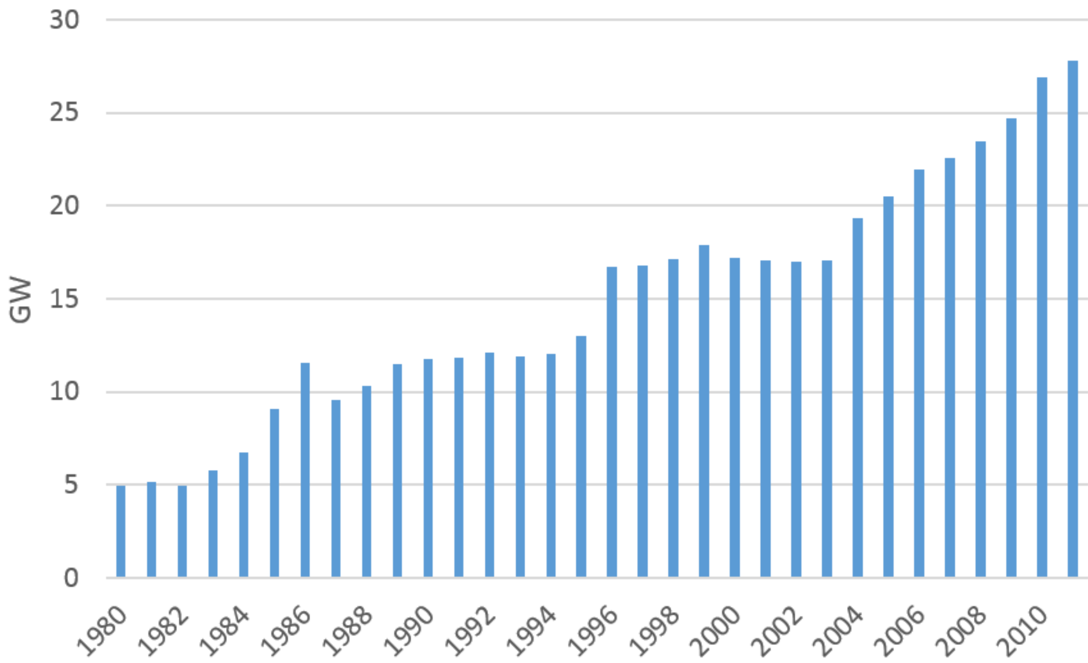

Figure 2.3: Development of installed capacity
Data source: U.S. Energy Information Administration [5]

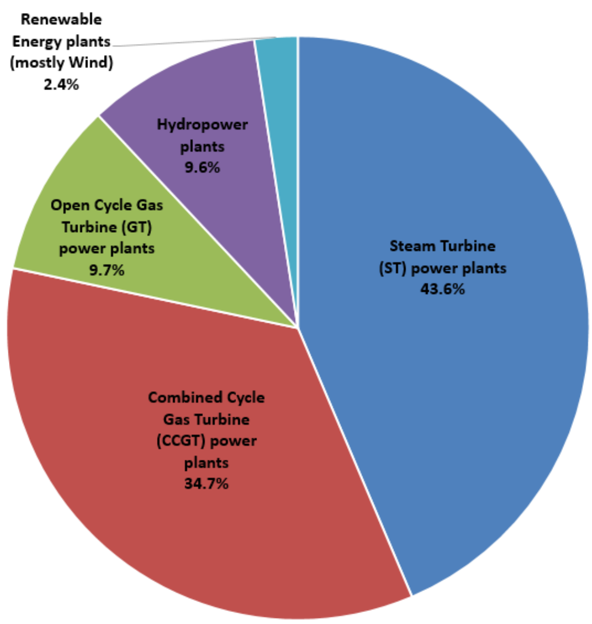

Figure 2.4: Installed capacity by technology
Data source: EEHC 2011/2012 annual report [2]

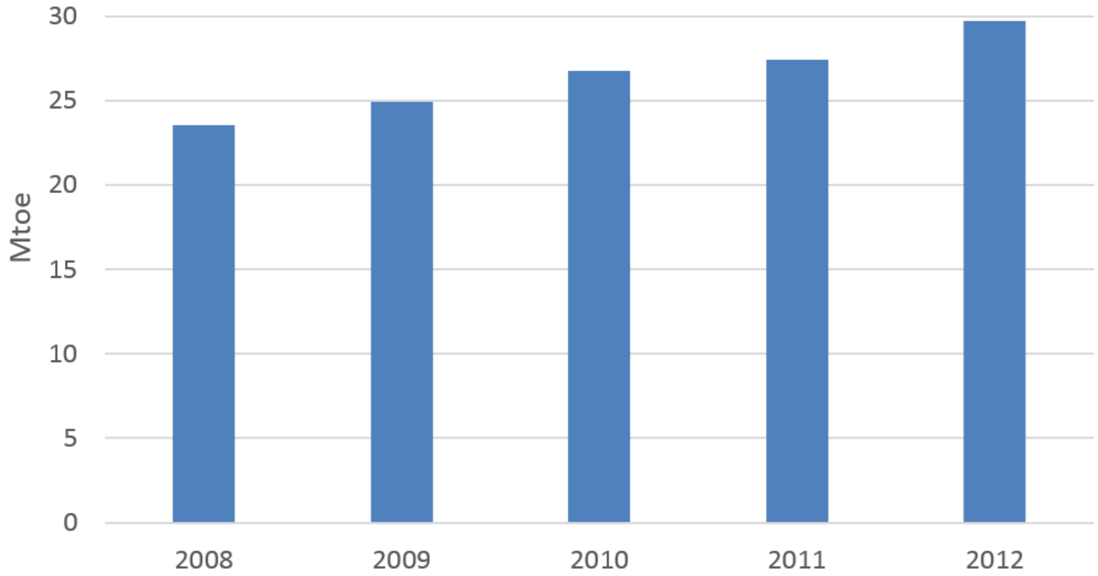

Figure 2.5: Development of fossil fuel consumption
Data source: EEHC 2011/2012 annual report [2]

to about 30 Mtoe in 2012 (see figure 2.5). The electricity generated in Egypt in year 2011/2012 is 157 TWh, 90.5% generated from thermal power plants fired by fossil fuel, while 9.5% generated from renewables (8.2% from hydropower and 1.3% from other renewables; predominantly wind power).

The power generation from hydropower resources started in 1960, with the construction of the 280 MW Aswan 1 hydropower plant. In 1967, the 2,100 MW High Dam hydropower plant was installed. In 1985, the 270 MW Aswan 2 hydropower plant was installed. Recently only two run-of-river hydropower plants were installed namely Isna plant (86 MW) in 1993, and Naga-Hamadi plant (64 MW) in 2008. In 2012, Egypt generated 13.2 TWh of hydroelectricity, meaning that hydropower is Egypt's third-largest energy source after natural gas and oil. It is worth mentioning that most of the Nile River's hydropower potential has already been exploited.

After the hydropower, wind power is the most mature renewable technology in Egypt. The first wind farm installed in 1993 is Hurghada wind farm (5 MW) with turbines ranges between 100 and 300 kW, the farm's electricity generation reached 5 GWh in 2013. The main and biggest wind park in Egypt is Zafarana wind park with total installed capacity of 545 MW, the park was installed through several stages/projects since 2001, the farm currently includes 700 turbines (with installed capacity of 600 kW, 660 kW, and 850 kW), the farm's electricity generation reached 1.3 TWh in 2013. Zafarana wind Farm was financed in cooperation with development banks from Germany, Denmark, Spain, and Japan.

In 2011, the first Integrated Solar Combined Cycle (ISCC) power plant was installed in Kuriemat (south of Cairo), the plant's total installed capacity is 140 MW. The combined cycle power plant is fired by natural gas, and is integrated with 20 MW parabolic trough solar field. The World Bank and the Japan International Cooperation Agency helped to finance the construction of the aforementioned ISCC plant.

2.1.3 Electricity transmission

Egypt has a national unified electricity grid (50 Hz system), the main High Voltage (HV) transmission lines, especially the 500 kV voltage levels, were constructed to transmit the electricity generated from Upper Egypt (through hydropower plants) to the demand centres near Cairo. Today more than 40% of the electricity generation is located in Upper Egypt and East Delta, and transmitted through the utility grid to the demand centres. Figure 2.6 2.6 shows the national unified electricity grid.

There is a transnational interconnection between Egypt and Libya on a side, and between Egypt and Jordan on another side. The Jordanian grid is connected to the Syrian grid which is connected to the Lebanese grid, hence Egypt can trade electricity with Libya, Jordan, Syria, and Lebanon. Table 2.2 shows some technical data related to such transnational interconnection.

Egypt has an ambitious goal to be a hub for electricity interconnection in the region (see figure 2.7) through two main interconnection axes; the Arab interconnection axis and the African interconnection axis. The Arab interconnection axis, Egypt is already connected to Arab Mashreq

Figure 2.6: The national unified electricity grid
Courtesy of the Arab Union of Electricity

Table 2.2: Egypt transnational interconnection
Data source: EEHC 2011/2012 annual report [2] and RCREEE [24]

Description	Egypt/Libya	Egypt/Jordan		
Interconnection voltage (kV)	220	400		
Interconnected Country	Libya	Jordan	Syria	Lebanon
Capacity (MW)	240	550	350	100
Exported electricity in 2012 (GWh)	100	1,277	220	82
Imported electricity in 2012 (GWh)	64	36	2	---

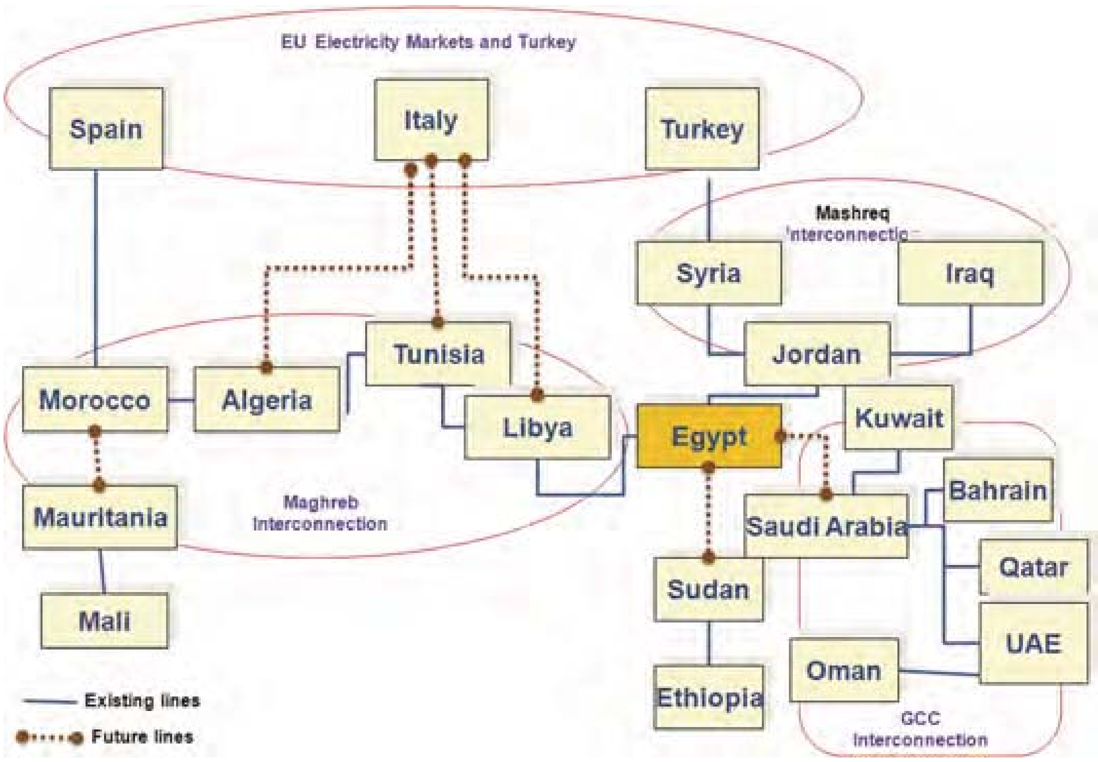

Figure 2.7: Egypt's position for becoming a regional energy hub
Source: Africa Development Bank [35]

countries (Jordan, Syria, and Lebanon), and regarding the interconnection of the Arab Maghreb countries (Libya, Tunisia, Algeria, and Morocco) the operational arrangements are under preparation for the interconnection line between Libya and Tunisia. The interconnection with the Gulf countries shall be through Kingdom of Saudi Arabia, a techno-economic feasibility study for such interconnection has been completed and it concluded the feasibility of power exchange up to 3 GW between the two countries [2].

The African interconnection axis aims to link the North African countries with some other African countries. A techno-economic feasibility study was conducted to investigate the interconnection with Inga Dam in Democratic Republic of Congo (DRC) to enable transmitting 40 GW of hydro power generated from Inga to North Africa and Europe (passing through Central Africa and Sudan). Another techno-economic feasibility study for interconnecting Egypt with Sudan and Ethiopia was conducted in 2008, which concluded the feasibility of exporting 2 GW from Ethiopia to Egypt passing through Sudan [2]. Egypt also aims to interconnect directly with Europe through Greece, hence Egypt is currently investigating the feasibility of establishing 2000 km High Voltage Direct Current (HVDC) transmission line (of which about 800 km would be through submarine cable) [2].

2.1.4 Electricity consumption

According to the Central Agency for Public Mobilization and Statistics (CAPMAS), Egypt's population has been doubled from 40 million in 1980 to about 80 million in 2011, during the same period according to the World Bank - the Gross Domestic Product (GDP) per capita (current USD) increased from USD 550 to USD 2,930. As a consequence of the rapid population and economic growth, the electricity consumption has been increased from about 18 TWh in 1980 to about 130 TWh in 2011 (see figure 2.8). Currently there are nine electricity distribution companies under the umbrella of EEHC, each covers specific geographical

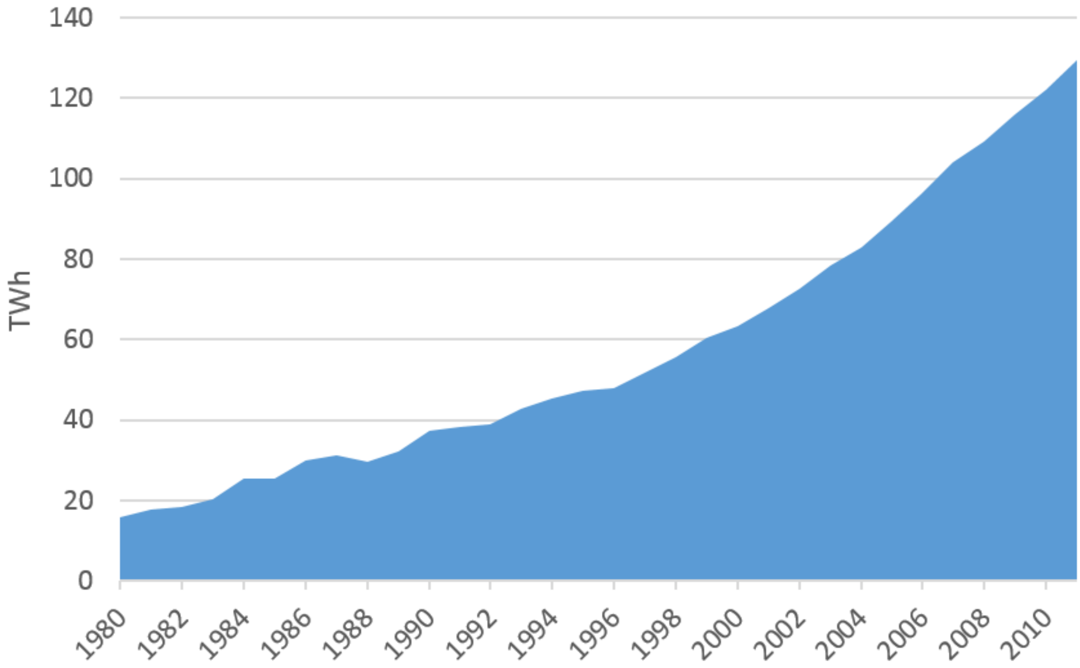

Figure 2.8: Development of net electricity consumption
Data source: U.S. Energy Information Administration [5]

zones and mostly named after that zone. Those companies possess the exclusive right to distribute electricity on medium and low voltage levels to all sectors, while EETC possess the exclusive right to sell electricity to energy intensive industries on the higher voltage levels (i.e. 500 kV, 220 kV, 132 kV, and 66 KV) [4]. It is worth mentioning that about 42% of the electricity generated in 2012 was consumed by the residential sector, compared to about 31% consumed by the industrial sector (see figure 2.9).

2.1.5 Energy subsidy and electricity tariff

Electricity generation in Egypt is dominantly fuelled by natural gas, in 2012 natural gas accounted for more than 84% of the total fuel consumption in power generation [2]. It is obvious that gas prices in Arab markets are way below the world market price; they are even less than the opportunity values [22]. Figure 2.10 shows that gas prices in almost all Arab countries are indeed below the marginal cost of new supply, which is estimated to be in the range of USD 3-6/MMBtu.

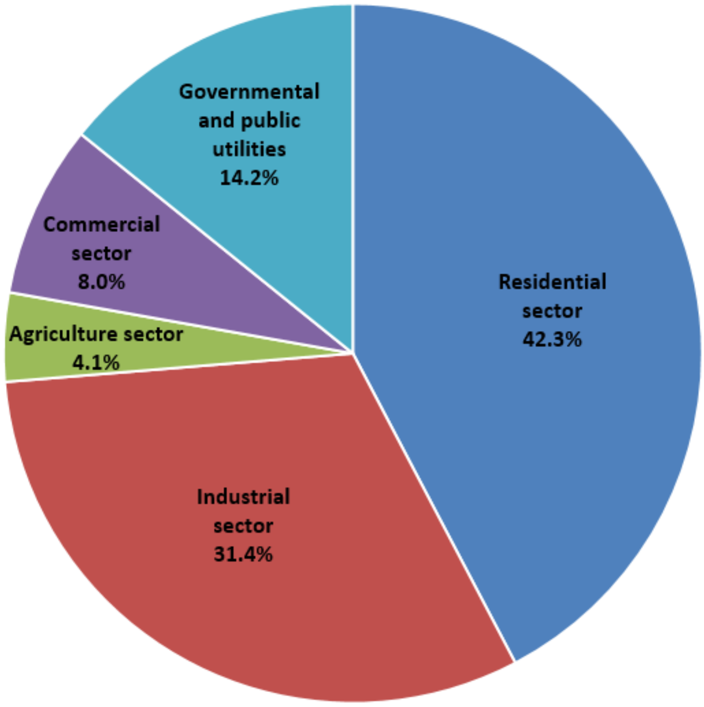

Figure 2.9: Electricity consumed by usage purpose
Data source: EEHC 2011/2012 annual report [2]

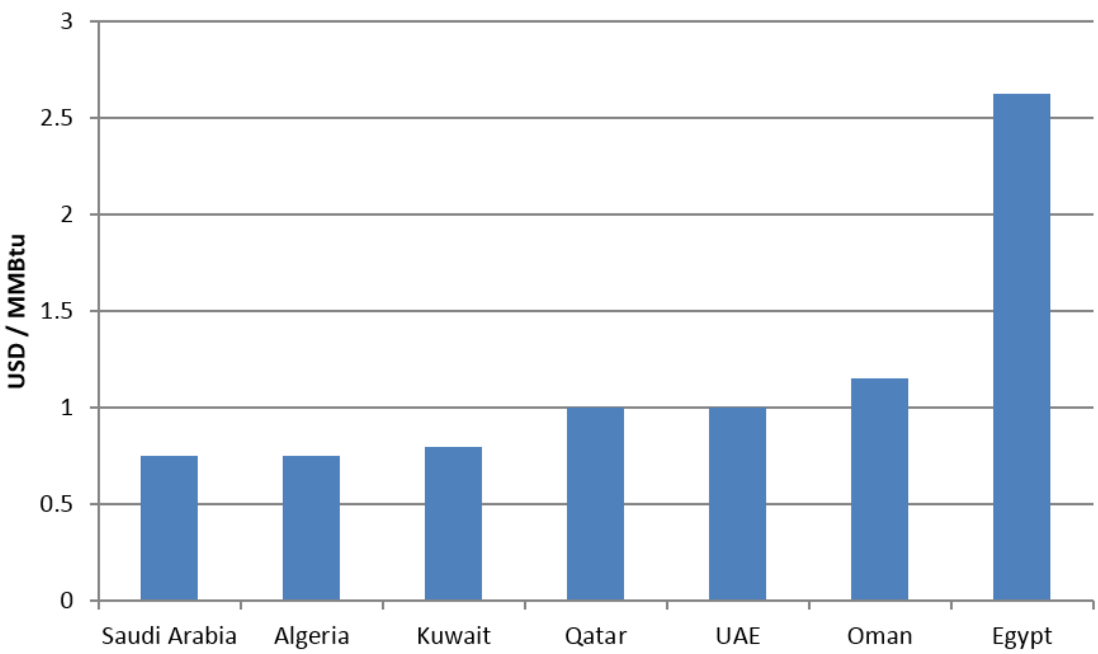

Figure 2.10: Gas prices in Arab markets
Data source: Darbouche, 2013 [22]

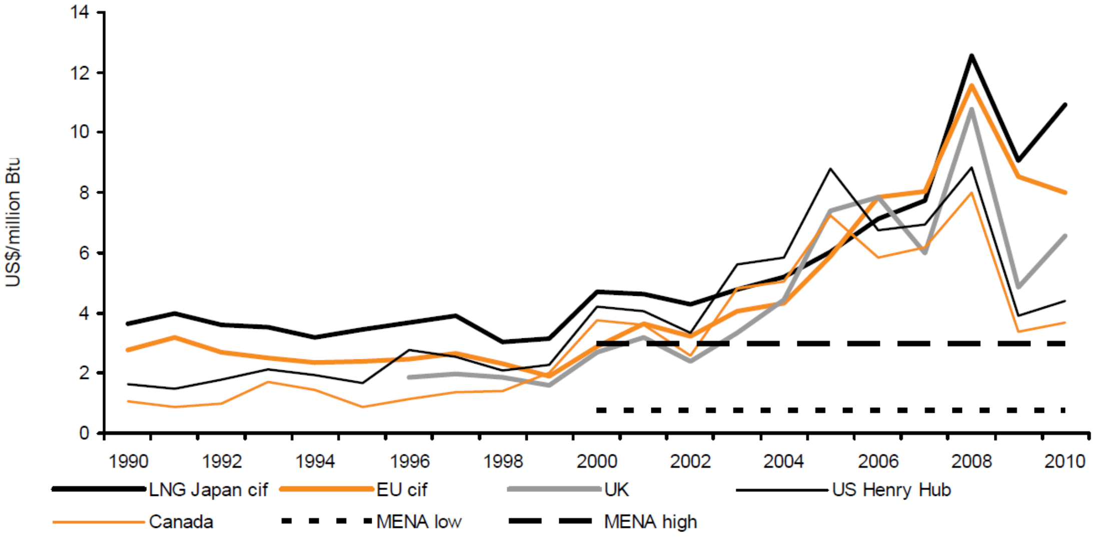

Figure 2.11: Regional gas pricing in a global perspective
Data source: BP and Rasmala [46]

The gas pricing in different markets is continuously fluctuating, from the global perspective it is clear that the current gas prices are quite low. Figure 2.11 shows that since year 2000, most of the international gas market prices (e.g. US, Canada, Europe, UK, and Japan) were changing rapidly, while the gas prices in most of Middle East and North Africa (MENA) countries were somehow maintained at relatively low values.

Recently, it was clear that most gas-short Arab countries recognized that unless they overcome political differences in order to secure gas supplies from neighbouring countries, they will have to pay the international gas price. During the last four years, Egypt's gas production has been declining while its demand grows with an annual rate of 10%, this means that shortly Egypt would not be able to export gas anymore and it will have no other option than importing expensive gas from abroad [22].

Electricity tariff in Egypt is designed based on the supply voltage level and the purpose of consumption. The tariff is calculated by adding share of the grid investments, operation, and losses to the main generation cost paid to the generation companies, this resulting in increased tariff of the lower voltage levels. The tariff also varies according to the purpose of consumption (industrial, residential, commercial, agriculture ...etc.), tariff structure applied to residential and a commercial sector is based on ascending blocks, the higher the consumption the higher the tariff, i.e. monthly electricity bill is calculated by dividing the total consumption over the tariff blocks.

Since 2012 Egypt experiences frequent blackouts, according to government officials the reasons include rising demand, natural gas supply shortages, ageing infrastructure, and inadequate generation and transmission capacity. It is obvious that ongoing political turmoil and social unrest hindered the power generation expansion plan, hence electricity consumption is increasing much faster than capacity expansions. During the summer months the natural gas amount directed to the power generation sector is not sufficient to cover the electricity demand, so Egypt usually imports fuel oil and diesel to cover the natural gas shortage [5].

It is clear that Egypt has one of the lowest electrify tariff in the world, and this is due to the fact that the fossil fuels are significantly subsidized (energy subsidy accounted for 73% of the total subsidies in 2010) [20]. The share of fuel subsidy in Egypt's budget increased from 9% in 2002 to 22% in 2013, and when electricity subsidies (for both inputs and end-user prices) are included, this share is well above 30%. The expenditure on fuel subsidies is growing at compound annual growth rate of 26% between 2002 and 2013 [21]. In other words, the share of the expenditure on fuel subsidies in the Egyptian GDP has been increased from 3% in 2002 to 7% in 2013.

Recently, the Egyptian government realized that it could not maintain the energy subsidies at such high level anymore, as the fiscal deficit reached 14% of the GDP in 2013. Hence the government intended to reduce the energy subsidy. In July 2014, sweeping measures to increase fuel prices have been introduced, and the government stated that this is just a first step towards reaching the international market price for most of the fuels in the near future (no precise roadmap has been announced), table 2.3 elaborates on the price increase of the fuels used for electricity generation. Correspondingly the electricity tariff also increased, table 2.4 shows the corresponding increase in electricity tariff for energy intensive

Table 2.3: Price increase of the fuels used for electricity generation as of July 2014
Data source: IISD-GSI [21]

Fuel used for electricity generation	Previously	As of July 2014	Percentage of increase
Natural Gas [USD/million BTU]	1.77	3.00	70 %
Diesel [LE/litre]	1.10	1.80	64 %
Heavy Fuel Oil [LE/ton]	2,300	2,300	0.0 %

* 1 Egyptian Pound (LE) = 0.11 EUR

consumers (dominated by industrial sector), while table 2.5 shows the corresponding increase in electricity tariff for residential, commercial and other sectors fed on the low voltage level.

2.2 Future Expansion Plans and Scenarios

2.2.1 Official future expansion plan

The EEHC set five-year expansion plans to show the future goals to increase the installed capacity of the Egyptian power plant portfolio. Before discussing the current expansion plan (2012 - 2017), shedding light on the previous expansion plan (2007 - 2012) is important to realize to which extend the EEHC could accomplish its plans. The last expansion plan (2007 - 2012) stated adding 7 GW installed capacity, consisting of 3 GW from combined cycle power plants and 4 GW from steam power plants. By the end date of the expansion plan, only 4.4 GW was achieved. As EEHC cannot achieve the planned expansion capacity, it had to consider adding 2.6 GW open gas turbine power plants through fast track projects [2].

The current five-year expansion plan (2012 - 2017) stated adding 11.1 GW of thermal generation capacity (6.9 GW by EEHC, while 4.2 GW to be built, owned and operated by private sector). The total estimated

Table 2.4: Electricity tariff for energy intensive consumers
Data source: IISD-GSI [21]

Sector and Purpose	Previously		As of July 2014	
	Demand Charge (LE/kW-month)	Tariff (pt/kWh)	Demand Charge (LE/kW-month)	Tariff (pt/kWh)
Electricity sold on Extra High Voltage (500 kV and 220 kV)				
Kima company	---	4.7	---	4.7
Metro Ramsis (Line 2)	---	6.8	---	14.5
Fertilisers, petrochemicals, steel , cement, aluminium, and SUMED company	12.1	27.7 – 41.5*	10	34.1 – 51.1*
Other consumers	11.1	15.4	10	22.6
Electricity sold on High Voltage (132 kV and 66 kV)				
Metro Toura (Line 1)	---	11.3	---	16.3
Fertilisers, petrochemicals, steel , cement, aluminium, and SUMED company	12.1	30.0 – 45.0*	20	35.8 – 53.7*
Other consumers	11.1	18.6	20	27.5
Electricity sold on Medium Voltage (22 kV and 11 kV)				
Fertilisers, petrochemicals, steel , cement, aluminium, and SUMED company	12.1	35.8 – 53.7*	30	38.3 – 57.5*
Glass, ceramic, and porcelain	11.6	32.7	30	41.5
Other consumers	11.1	25.5	30	36.5

* Price during off-peak (first value) – price during peak (second value)

** 1 Egyptian Pound (LE) = 100 piasters (pt) = 0.11 EUR

Table 2.5: Electricity tariff for residential, commercial and other sectors fed on low voltage level

Data source: IISD-GSI [21]

Purpose / Consumption Tiers	Previous Tariff (pt/kWh)	Tariff as of July 2014 (pt/kWh)
Electricity sold to residential sector		
First 50 kWh	5.0	7.5
51 kWh to 100 kWh	12.0	14.5
1011 kWh to 200 kWh	12.0	16.0
201 kWh to 350 kWh	19.0	24.0
351 kWh to 650 kWh	29.0	34.0
651 kWh to 1000 kWh	53.0	60.0
More than 1000 kWh	67.0	74.0
Electricity sold to commercial sector		
First 100 kWh	27.0	30.0
101 kWh to 250 kWh	41.0	44.0
251 kWh to 600 kWh	53.0	59.0
601 kWh to 1000 kWh	67.0	78.0
More than 1000 kWh	72.0	83.0
Electricity sold for specific purposes		
Irrigation	11.2	17.0
Public lighting	29.0	36.6
Other consumers	47.5	56.6

* 1 Egyptian Pound (LE) = 100 piasters (pt) = 0.11 EUR

Table 2.6: Egypt's official generation expansion plan (2012-2017)
Data source: Ministry of Electricity and Energy[10]

Type	Planned plant	Planned installed capacity (MW)				
		12/13	13/14	14/15	15/16	16/17
Renewables	Wind		360	850	1100	540
	CSP				100	
	PV				20	20
	Mini & Small Hydro Units			30		
Added Renewables Capacity (MW)		---	360	880	1220	560
Share of total installed capacity		0 %	10 %	37%	32 %	10 %
Conventional	Abu Kir 2 - ST	1300				
	Ain Sokhna - ST		1300			
	Suez - ST				650	
	Helwan South - ST					1950
	Bani Suif - ST					650
	Qena - ST				650	650
	Damanhur - ST					650
	Cairo West - ST					650
	Assuit - ST					650
	Banha - CCGT	250	500			
	Giza North - CCGT	500	1250	500		
	Dairout BOO - CCGT			1000	1250	
	Damitta west - GT	500				
Added Conventional Capacity (MW)		2250	3050	1500	2550	5200
Share of total installed capacity		100 %	89 %	63 %	68 %	90 %
Total added Capacity MW		2550	3410	2380	3770	5760

investments for this generation expansion plan is about EGP 77 billion; EGP 43 billion to be financed by EEHC and its affiliated companies, while EGP 34 billion to be financed by private sector [2]. Table 2.6 shows the current official generation expansion plan [10], and it is worth mentioning that most of the newly built thermal power plants are supporting dual firing (natural gas and oil) due to the uncertainty regarding the availability natural gas to fuel the whole thermal power plant portfolio in the future [25].

NREA announced its goal to increase renewable energy share to reach 20% of the total generated energy by 2020 as 12% wind, 6% Hydro and 2% solar. NREA aims that such renewable energy projects shall be implemented through two parallel paths as follows [4]:

Table 2.7: Planned wind power projects
Data source: NREA [4]

Project	Capacity (MW)	Expected Operation	Notes
Governmental projects with total capacity of 1,340 MW EETC will be committed to purchase all generated electricity			
Gulf of Zayt (1)	**200**	**2014**	In cooperation with KfW, European Investment Bank (EIB), and European Commission (finance 340 M EUR)
Gulf of Zayt (2)	**220**	**2016**	In cooperation with Japanese government (estimated cost 308M EUR)
Gulf of Zayt (3)	**120**	**2016**	In cooperation with Spanish government (estimated cost 168M EUR)
Gulf of Suez (1)	**200**	**2017**	In cooperation with European partners (estimated cost 280M EUR)
Gulf of Suez (2)	**200**	**2018**	In cooperation with Masder company (UAE government) (estimated cost 280M EUR)
Gulf of Suez (3)	**200**	**2018**	In cooperation with European partners (estimated cost 280M EUR)
West of Nile (1)	**200**	**2018**	In cooperation with Japanese government (estimated cost 280M EUR)
Competitive bidding projects with total capacity of 750 MW EETC will be committed to purchase all generated electricity			
Gulf of Suez (BOO-1)	**250**	**2016**	10 developers were shot listed in 2009 Offers will be submitted in 2014
Gulf of Suez (BOO-2)	**500**	**2018**	EETC and NREA are preparing to issue the tender through two phases (2x250 MW)
IPP with total capacity of 720 MW Investors shall sell generated electricity to his own customers or to feed his own load			
Gulf of Suez (IPP-1)	**120**	**2016**	Italgen company will install this wind farm to feed cement factories owned by Suez Cement Company
Gulf of Suez (IPP-2)	**600**	**2017**	NREA announced 6 pieces of land each is 15 km^2 (100 MW), and it received 7 offers which are currently under evaluation

- projects led by the government (i.e. 33% of the plan's total installed capacities)
- projects led by the private sector (i.e. 67% of the plan's total installed capacities)

In this context the government allocated vast areas of land for wind power projects as as follows [4]:

- about 1,420 sq. km in the West Coast of the Gulf of Suez between Gabal El Zayt and Ras Gharib (near the Red Sea coast)
- about 6,420 sq. km in east and west of the Nile river (Beni Suef, Minya, and Assiut Governorates)

Table 2.8: Planned solar power projects
Data source: NREA [4]

Project	Capacity (MW)	Expected Operation	Notes
Kom-Ombo - CSP	**100**	**2017**	With 4 hours storage capacity (estimated cost 628M EUR)
Kom-Ombo - PV	**20**	**2017**	By NREA, and in cooperation with French Development Agency (FDA)
Hurghada - PV	**20**	**2016**	By NREA, and in cooperation with Japan International Cooperation Agency (JICA)
Kom-Ombo - PV (BOO)	**200**	**2018**	10 PV plants each 20 MW (NREA's allocated land in Kom-Ombo). Private investor shall BOO the PV plants and EETC will be committed to purchase all generated electricity for 20 years.

With the goal to achieve 2% from solar power by 2020. In July 2012, the Cabinet approved the Egyptian Solar Plan in 2012 targeting to install about 3.5 GW by 2027. In this context the government allocated some land for solar power projects as as follows [4]:

- about 15 sq. km in Faries village and Kom-Ombo in Aswan (for PV plant)
- about 250 sq. km in Marsa Alam, Red Sea Governorate (for solar power plant; without specifying the intended technology)

Through personal communication with the EEHC, Elsobki (currently the head of NREA) managed to estimate the evolution of annual capacity expansion and electricity generation until 2022 [25], refer to figure 2.12 and figure 2.13.

It is worth mentioning that natural gas represented more than 84% of the total amount of the fuel used in 2012. Elsobki calculated the annual required fuel by multiplying the annual electricity generation by the specific fuel consumption of each plant [25], and the result is shown in figure 2.14. It is clear that Elsobki expected that until 2022 the most of the required fuel will be directed to the steam power plants then the combined cycle power plants, while a few percentage will be directed to the open cycle gas turbine plants that are expected to be in operation only during peak hours.

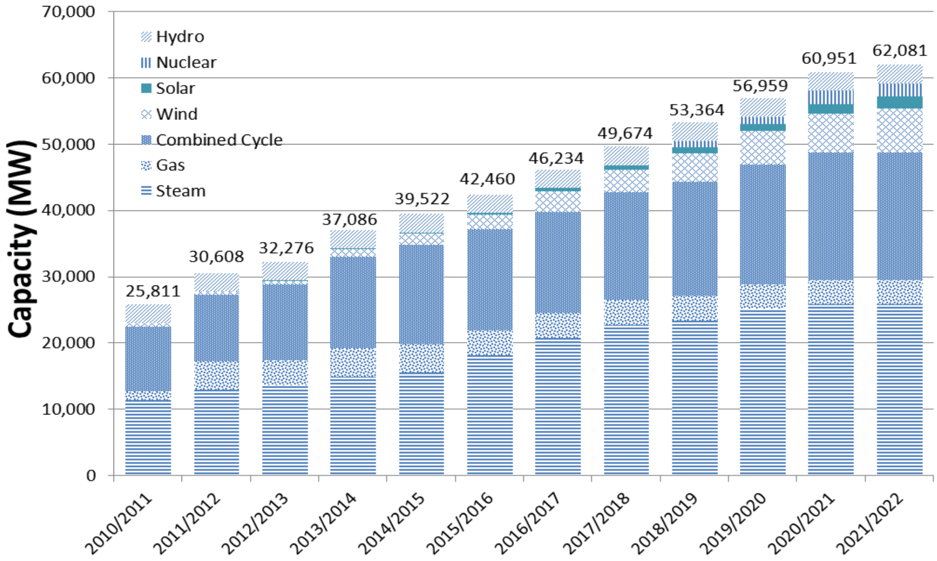

Figure 2.12: Expected annual capacity expansion until 2022
Data source: Elsobki, 2013 [25]

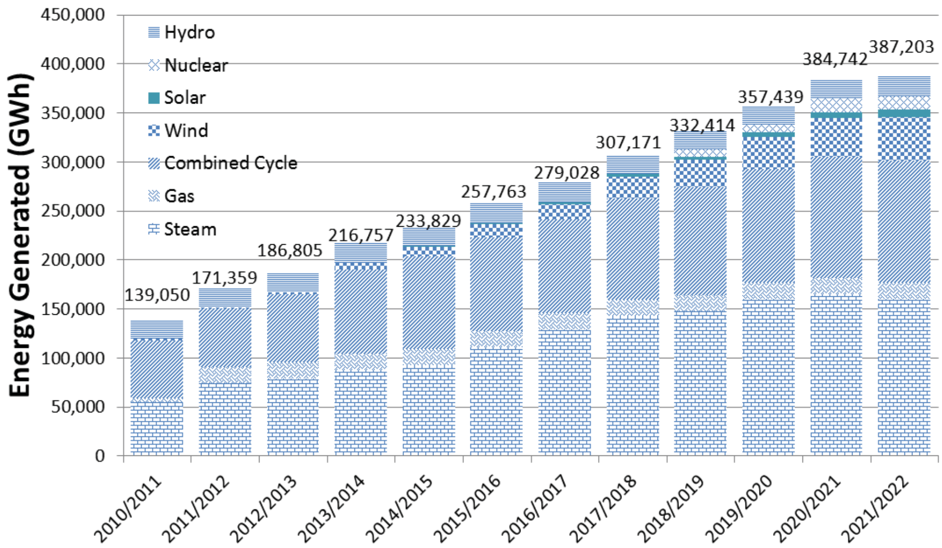

Figure 2.13: Expected annual electricity generation until 2022
Data source: Elsobki, 2013 [25]

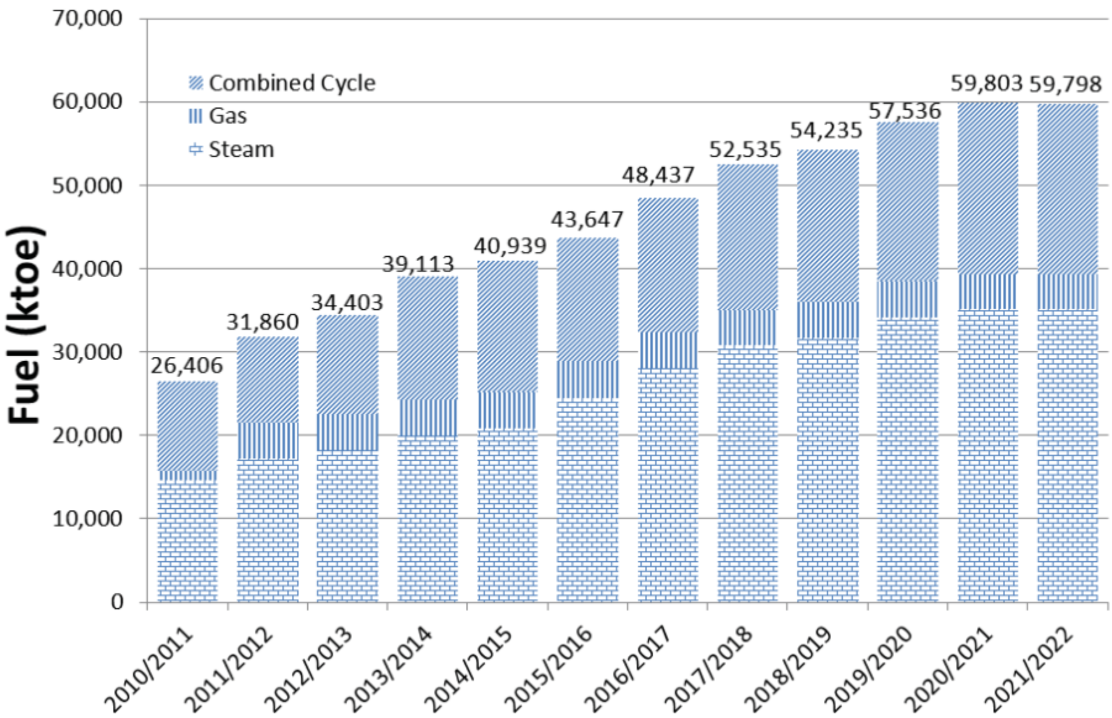

Figure 2.14: Expected annual fossil fuel consumption until 2022
Data source: Elsobki, 2013 [25]

The utility owned generation companies used a total of 24.5 Mtoe in 2011, Elsobki assumed that the fuel supply required for the electricity sector is increasing by an annual rate of 7% and accordingly he estimated the gap between the electricity sector fuel demand and the fuel supplied by the ministry of petroleum, figure 2.15 shows the additional required fuel annually until 2022.

Elsobki argued that -given the current energy situation in Egypt- 7% growth rate of fuel supply to the electricity sector most probably- would not be maintained by the ministry of petroleum, so he developed two other scenarios (more realistic scenario with 4% growth rate and extremely optimistic scenario with 10% growth rate). Figure 2.16 shows the additional fuel needed through each of the three scenarios until 2022. It is worth mentioning that the required amount of fossil fuel is expected to increase rapidly and even in the most optimistic scenario (with an annual increase of 10% in fuel supply) a fossil fuel supply shortage is expected to occur until 2020, referring to the more realistic scenario (with an annual increase of 4% in fuel supply) expensive fossil fuel imports

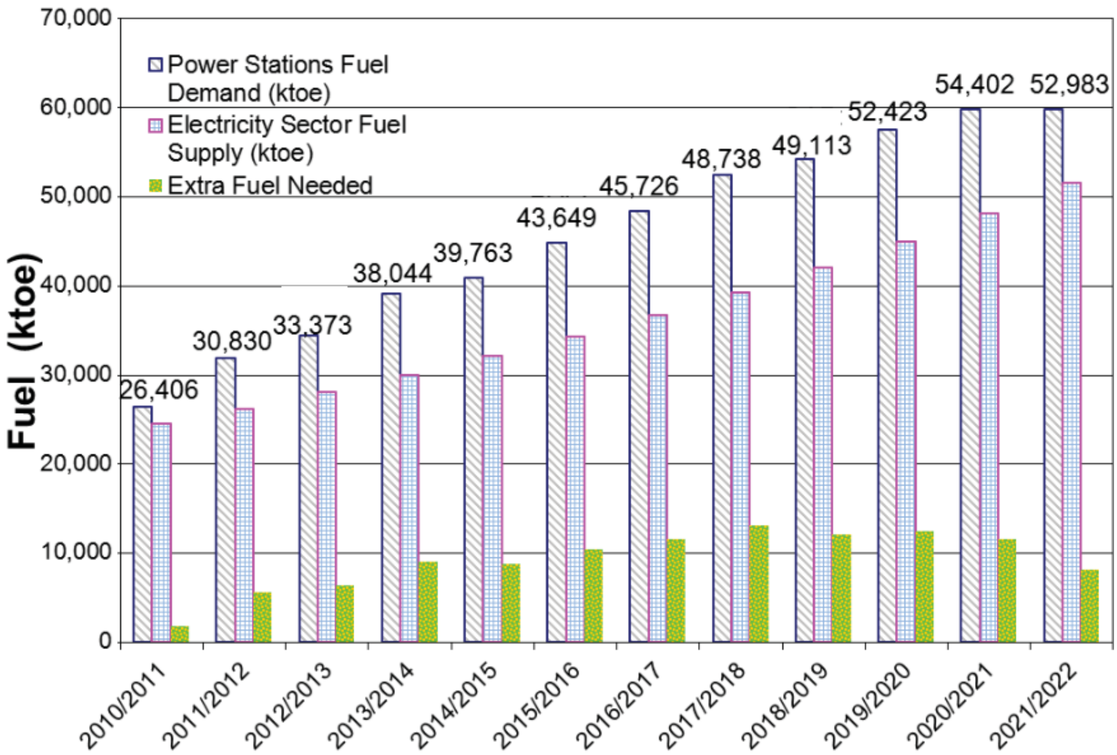

Figure 2.15: Expected annual additional required fuel until 2022
Data source: Elsobki, 2013 [25]

is highly expected unless a reasonable amount of electricity could be generated from other renewable energy resources.

2.2.2 JCEE future expansion scenarios

In 2010, the Egyptian-German Joint Committee on Renewable Energy, Energy Efficiency and Environmental Protection (JCEE) conducted a study on the future expansion of the installed capacity and expected development of electricity generation of Egypt's power sector, including expected fuel consumption development until 2030 [29]. The study followed straightforward quantitative model called Long-range Energy Alternatives Planning System (LEAP), developed by Stockholm Environment Institute (SEI). Additionally some specific simulation and optimization models have been used in a partial context and have been integrated with the aforementioned general model.

The study investigated three scenarios, which their main assumptions

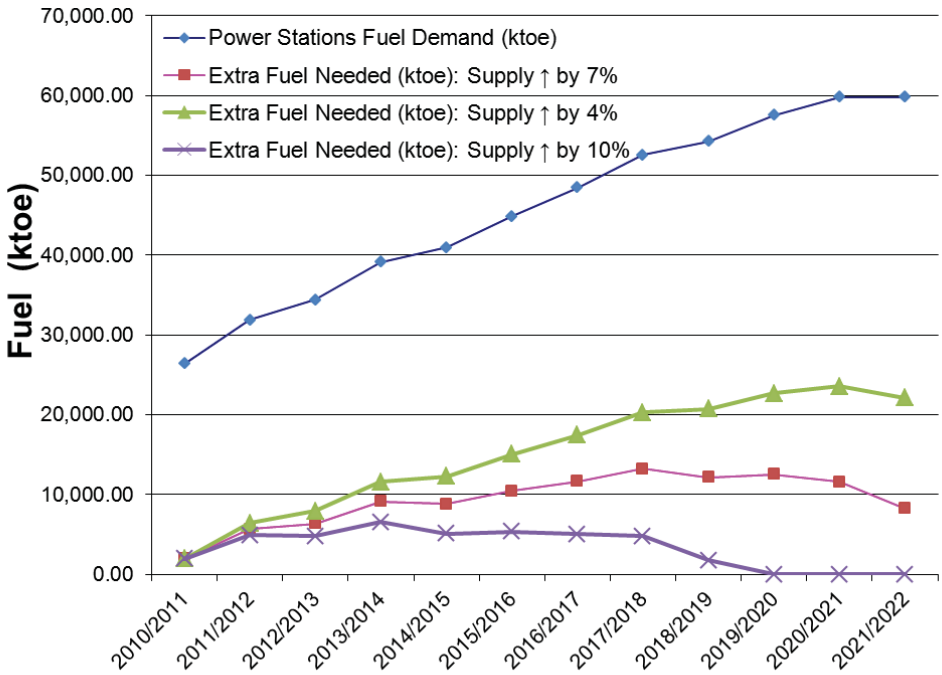

Figure 2.16: Expected impact of fuel supply variation on additional required fuel until 2022
Data source: Elsobki, 2013 [25]

and results are summarized in table 2.9 below. By 2030, the three scenarios assume 2 GW nuclear installed capacity and over 13.5 GW wind installed capacity. The study assumed zero-sum import-export balance, and the capacity factors for renewable technologies was assumed to be as follows: hydro 64%, solar 45%, and wind 35%. The thermal plants is assumed to operate according to the merit order and their availability was assumed to be 98%. Natural gas fired combined-cycle power plants were the preferred thermal technology followed by steam turbine plants, while open cycle gas turbine plants shall be operated only during peak hours [29]. The figures from figure 2.17 to figure 2.22 shows the development of installed capacity and electricity generation according to the three scenarios.

The estimated required fuels shown in table 2.9 is calculated based on the following plants' efficiencies: combined-cycle 58.7%, steam turbine 33.6%, gas turbine 37.3%, and diesel 28%. The fuel consumption associated with nuclear and renewable energy generation was estimated based on the British Petroleum methodology [29] (i.e. the primary en-

Table 2.9: Assumptions and results of the three JCEE study's scenarios
Data source: Figueroa de la Vega, 2010 [29]

Scenarios	Business-As-Usual (BAU)	High Economic Growth (HEG)	Substitution & Efficiency (SE)
Assumptions			
Annual GDP increase until 2030	3.1 %	4.5 %	4.5 %
Economy situation	will recover slowly from the current crisis	will grow drastically	will grow drastically [with significant energy efficiency measures and more renewable energy]
Annual electricity demand increase until 2030	3.8 %	4.9 %	4.6 %
Results			
Total installed capacity in 2030	78 GW	78 GW	83 GW
Total electricity generation in 2030	288 TWh	376 TWh	352 TWh
Share of renewable electricity in 2030	23 %	17 %	28 %
Total required fuel in 2030	52.1 Mtoe	71.4 Mtoe	66.8 Mtoe

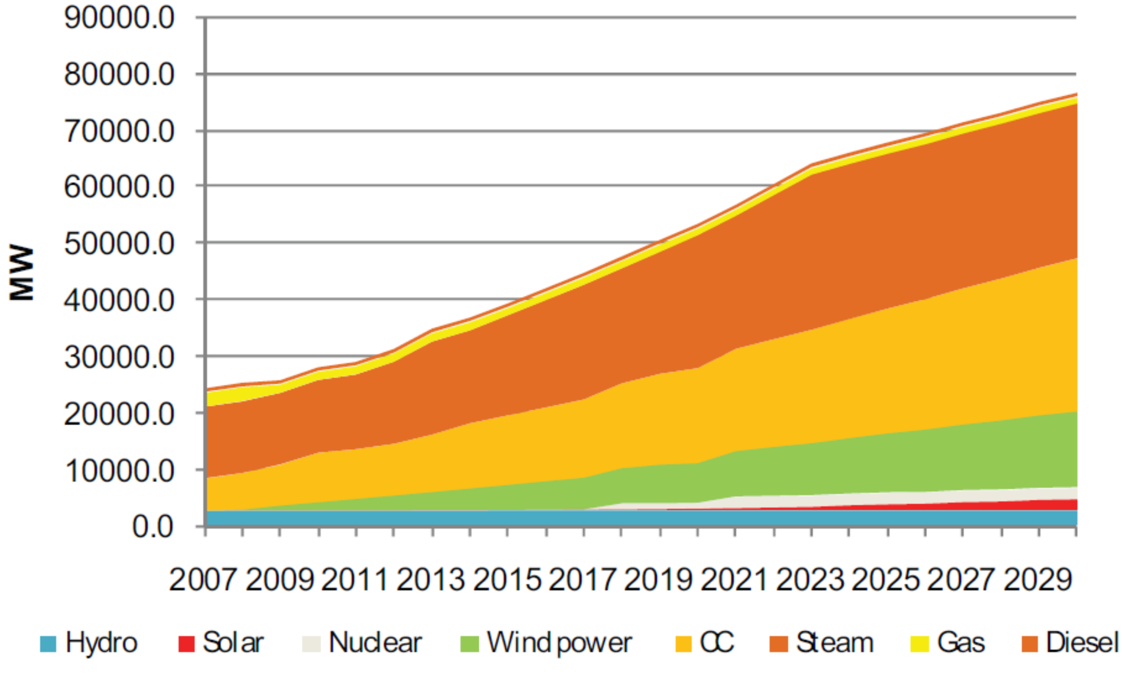

Figure 2.17: Development of installed capacity according to BAU and HEG scenarios
Data source: Figueroa de la Vega, 2010 [29]

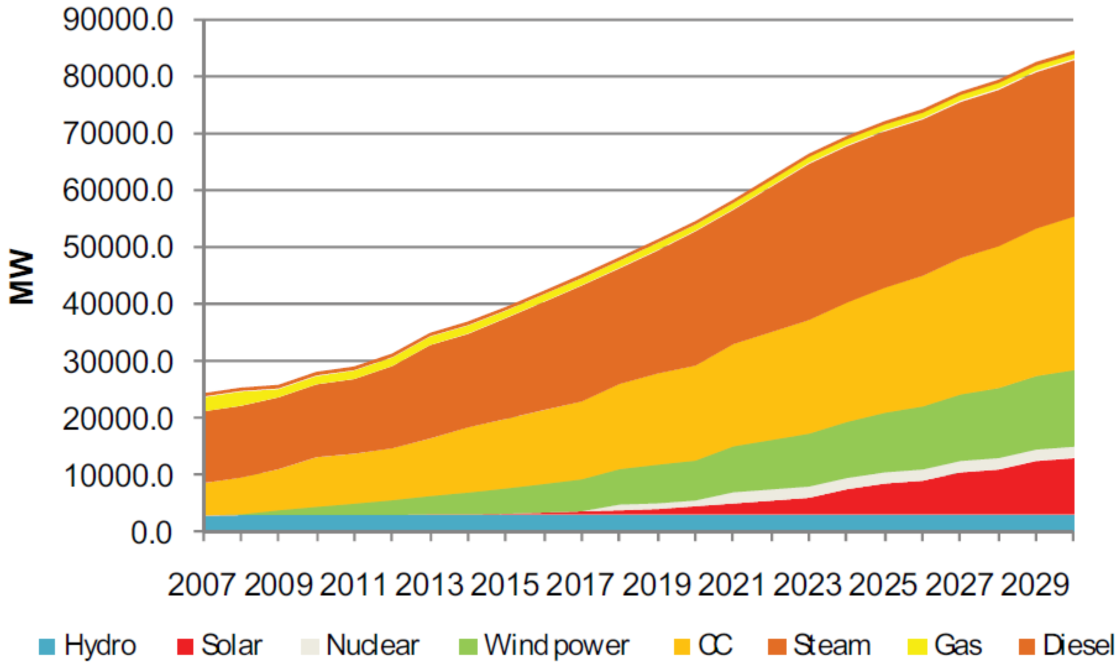

Figure 2.18: Development of installed capacity according to SE scenario
Data source: Figueroa de la Vega, 2010 [29]

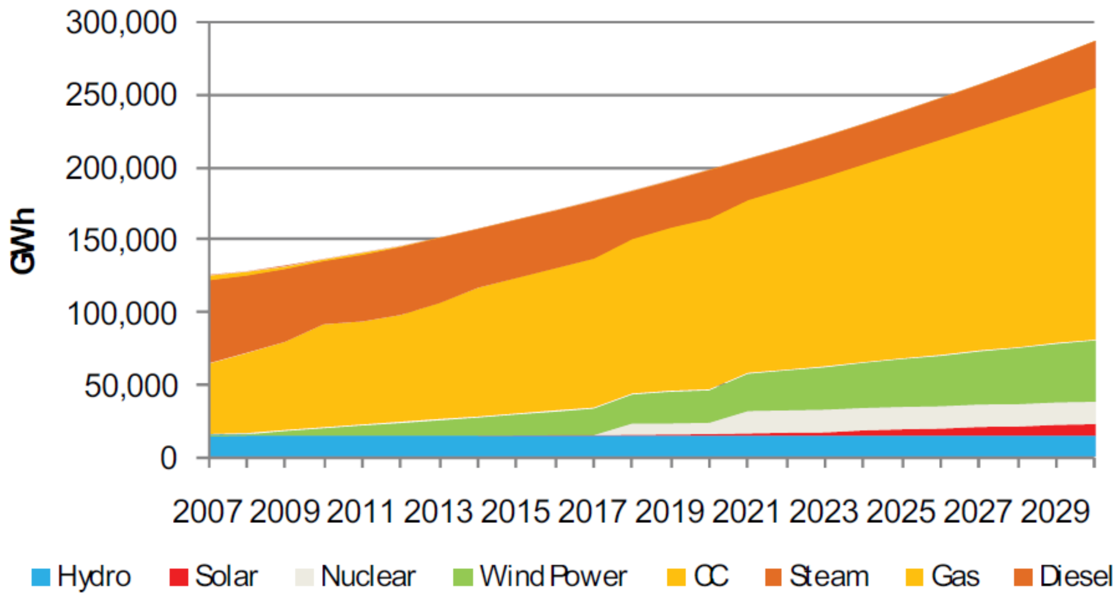

Figure 2.19: Development of electricity generation according to BAU scenario
Data source: Figueroa de la Vega, 2010 [29]

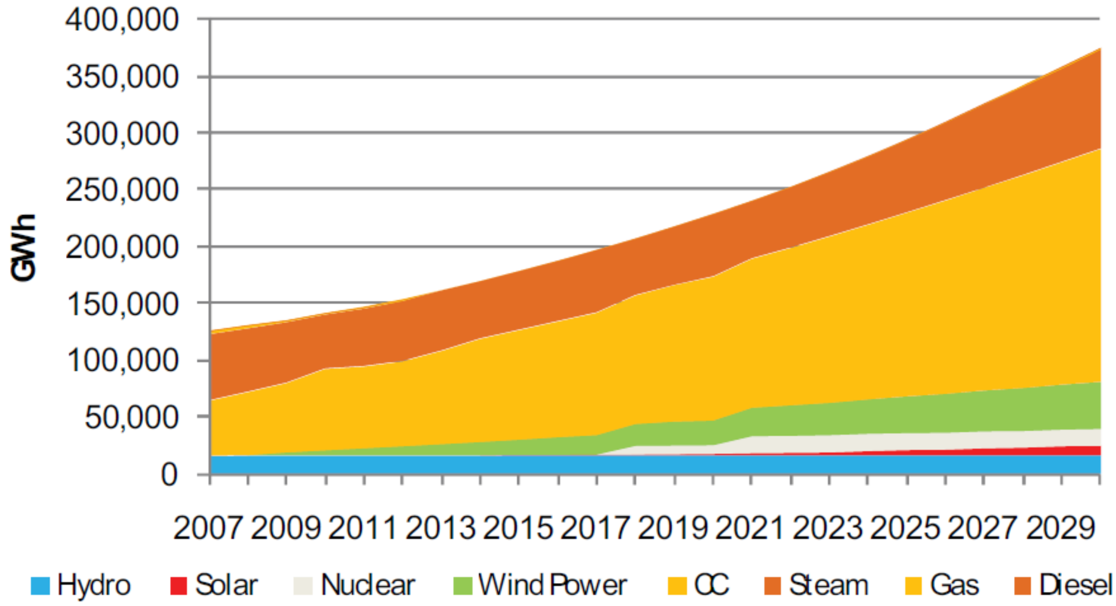

Figure 2.20: Development of electricity generation according to HEG scenario
Data source: Figueroa de la Vega, 2010 [29]

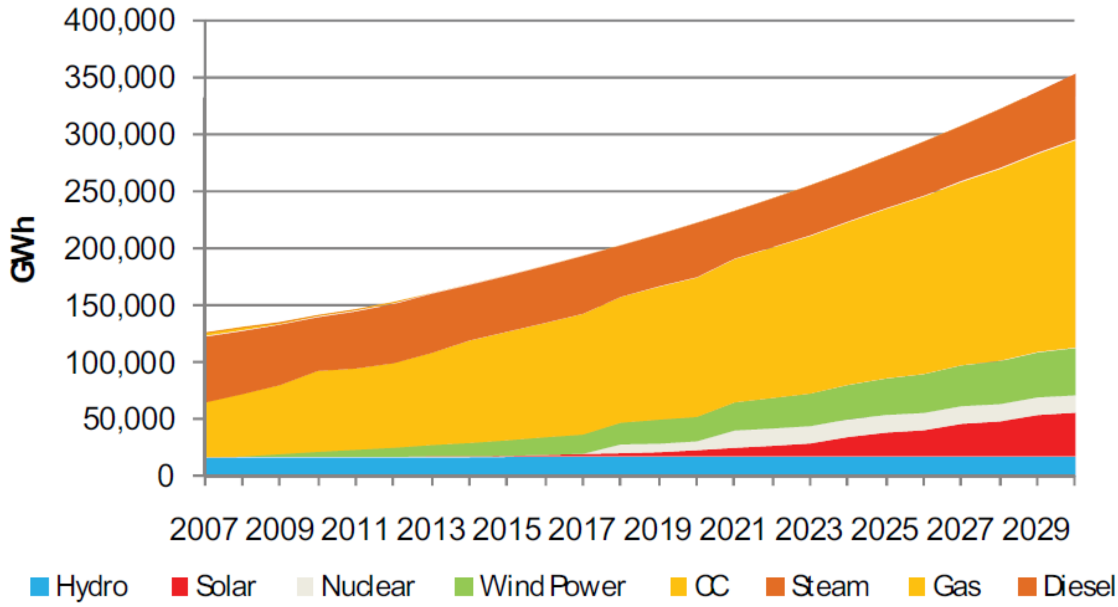

Figure 2.21: Development of electricity generation according to SE scenario
Data source: Figueroa de la Vega, 2010 [29]

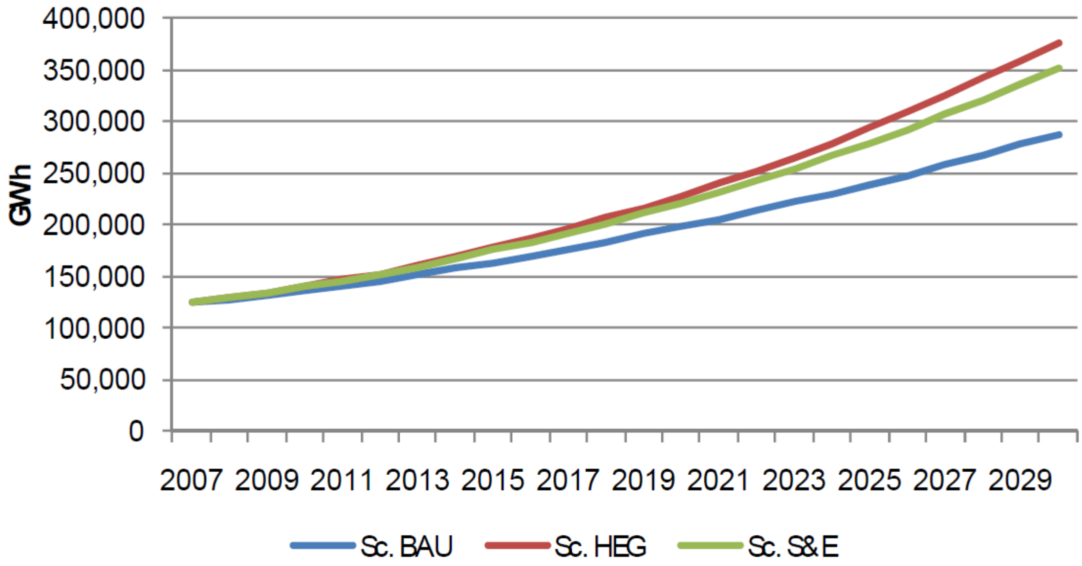

Figure 2.22: Development of total electricity generation according to the three scenarios
Data source: Figueroa de la Vega, 2010 [29]

ergy associated with nuclear and renewable energy generation have been derived by calculating the equivalent amount of fossil fuel required to generate the same amount of electricity in a thermal power plant with 38% efficiency).

The figures from figure 2.23 to figure 2.26 shows the fuel consumption development according to the three scenarios. It is noticeable that HEG scenario is expected to consume more fuel oil than BAU scenario. It is also clear that solar power replaces considerable amount of fuel oil in S/E scenario.

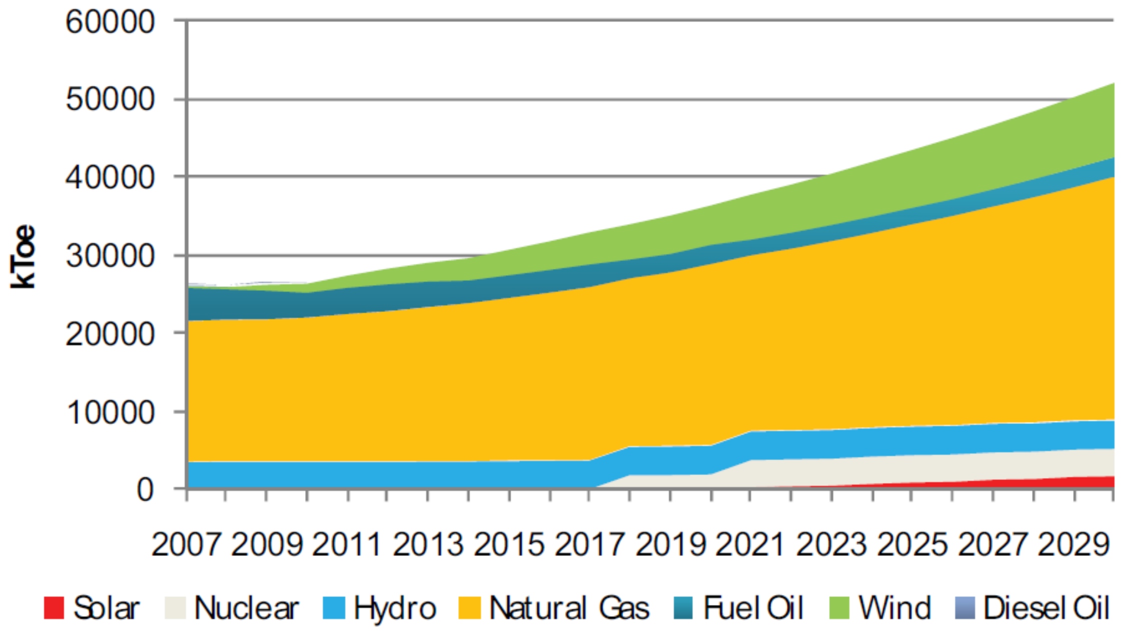

Figure 2.23: Development of fuel consumption according to BAU scenario
Data source: Figueroa de la Vega, 2010 [29]

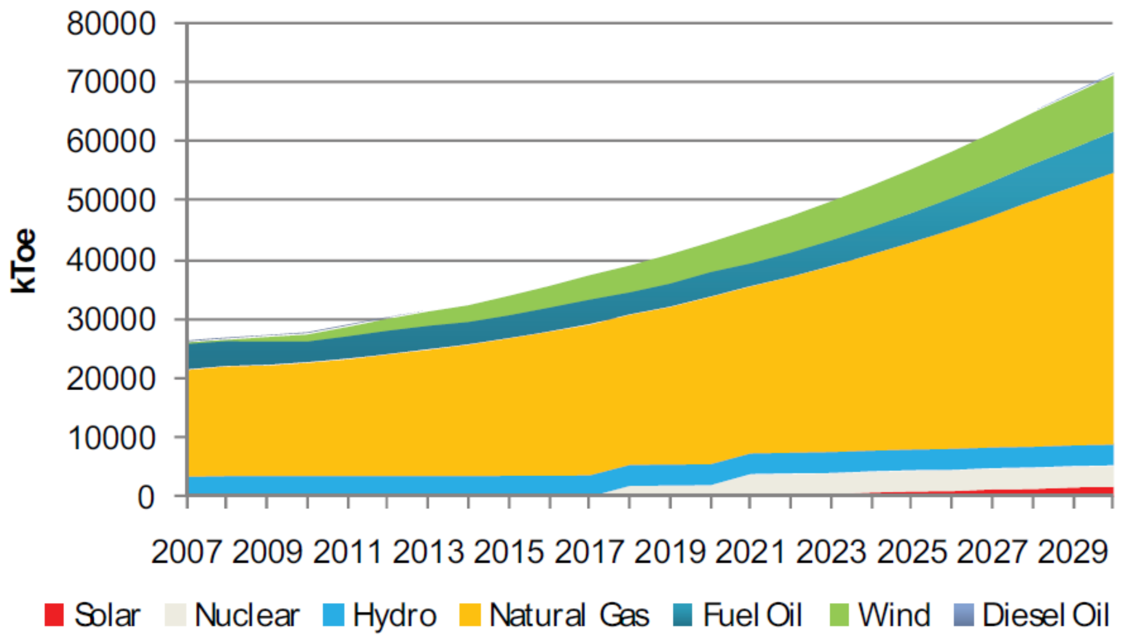

Figure 2.24: Development of fuel consumption according to HEG scenario
Data source: Figueroa de la Vega, 2010 [29]

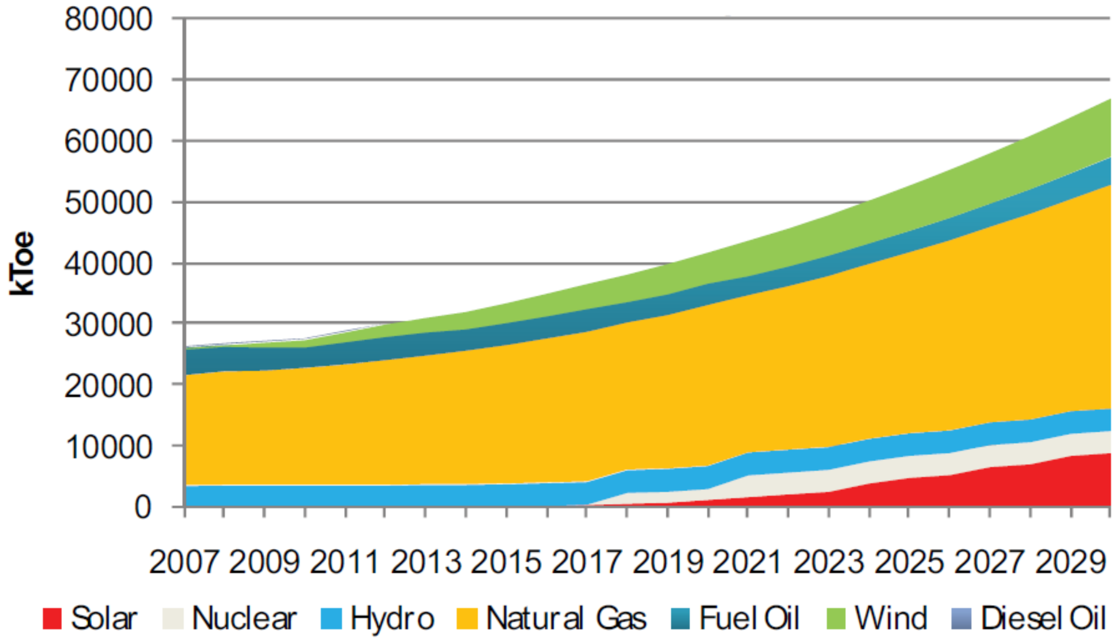

Figure 2.25: Development of fuel consumption according to SE scenario
Data source: Figueroa de la Vega, 2010 [29]

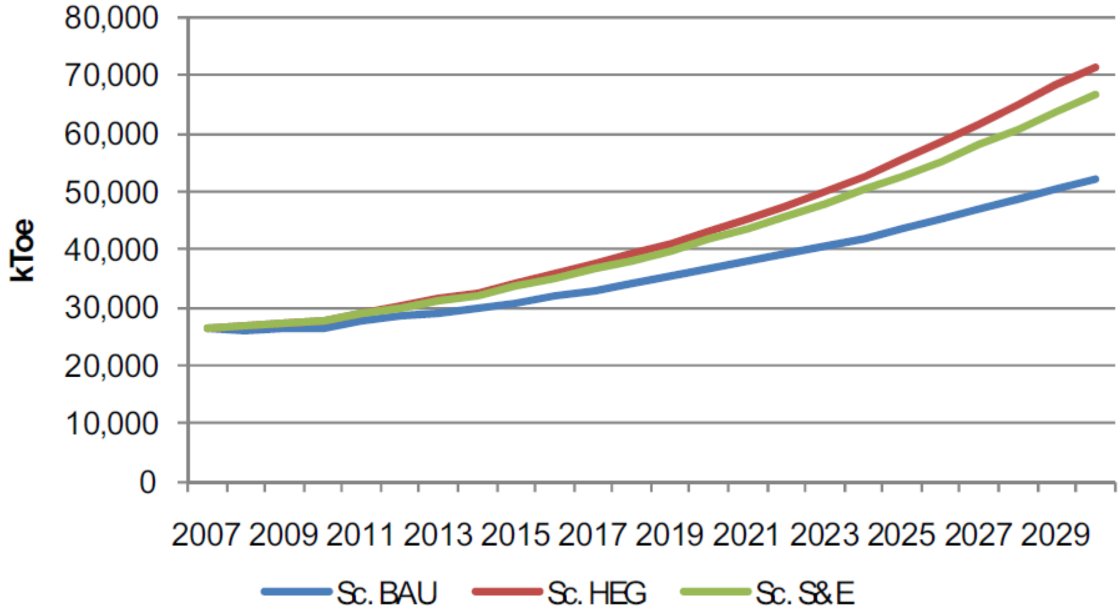

Figure 2.26: Development of fuel consumption according to the three scenarios
Data source: Figueroa de la Vega, 2010 [29]

3 Methodology

This chapter describes the scientific methodology followed during the research. This chapter is divided into two main topics; the identification of the renewable energies technology-specific hot spots and the use of the Renewable Energy Mix Capacity Expansion Model (REMix-CEM) Optimization Model.

The followed methodology to identify the optimal integration of RE technologies into Egypt's power plant portfolio could be divided into two main linked stages, as shown in figure 3.1. The objective of the methodology is to achieve the most cost-efficient integration of RE technologies into the existing power plant portfolio while maintaining the security of supply.

As mentioned in chapter 2, almost all hydropower potential in Egypt has been already exploited. Located in the Saharan Africa, there is no sufficient biomass resource to be considered for utility-scale power generation. So the most promising RE resources in Egypt are solar and wind resources, accordingly the current research focuses on CSP, utility-scale PV, and onshore wind power technologies.

The first stage tackles the hot spots identification for CSP, utility-scale PV, and onshore wind power through site-ranking analysis using Geographic Information Systems (GIS). Through the site-ranking analysis, the RE spatial resource availability (DNI, GHI, or wind speed), and the distance to demand centres and to existing transmission grid were the main ranking criteria. All sites that are not suitable to build respective RE technology projects have been excluded through applying relevant exclusion masks. This part will be discussed in detail in section 3.1.

The second stage comprises of preparing relevant databases for the optimization model and then running the model to generate the optimal RE integration based on couple of scenario runs. Firstly, for each of the identified hot spot, information about the hourly availability of the respective resource (DNI, GHI, or wind speed) and the maximum installable capacity were determined. Then the representative normalized hourly generation profiles of each technology at the respective hot spots were calculated for an entire year. Additionally comprehensive techno-economic data about the existing and candidate power plants, besides detailed information about Egypt's power system were also developed to concisely identify the whole system to the optimization model. Finally, the power system optimization model REMix-CEM was utilized to optimize the capacity expansion of conventional and RE technologies from a state-owned utility perspective. This part will be discussed in detail in the section 3.2.

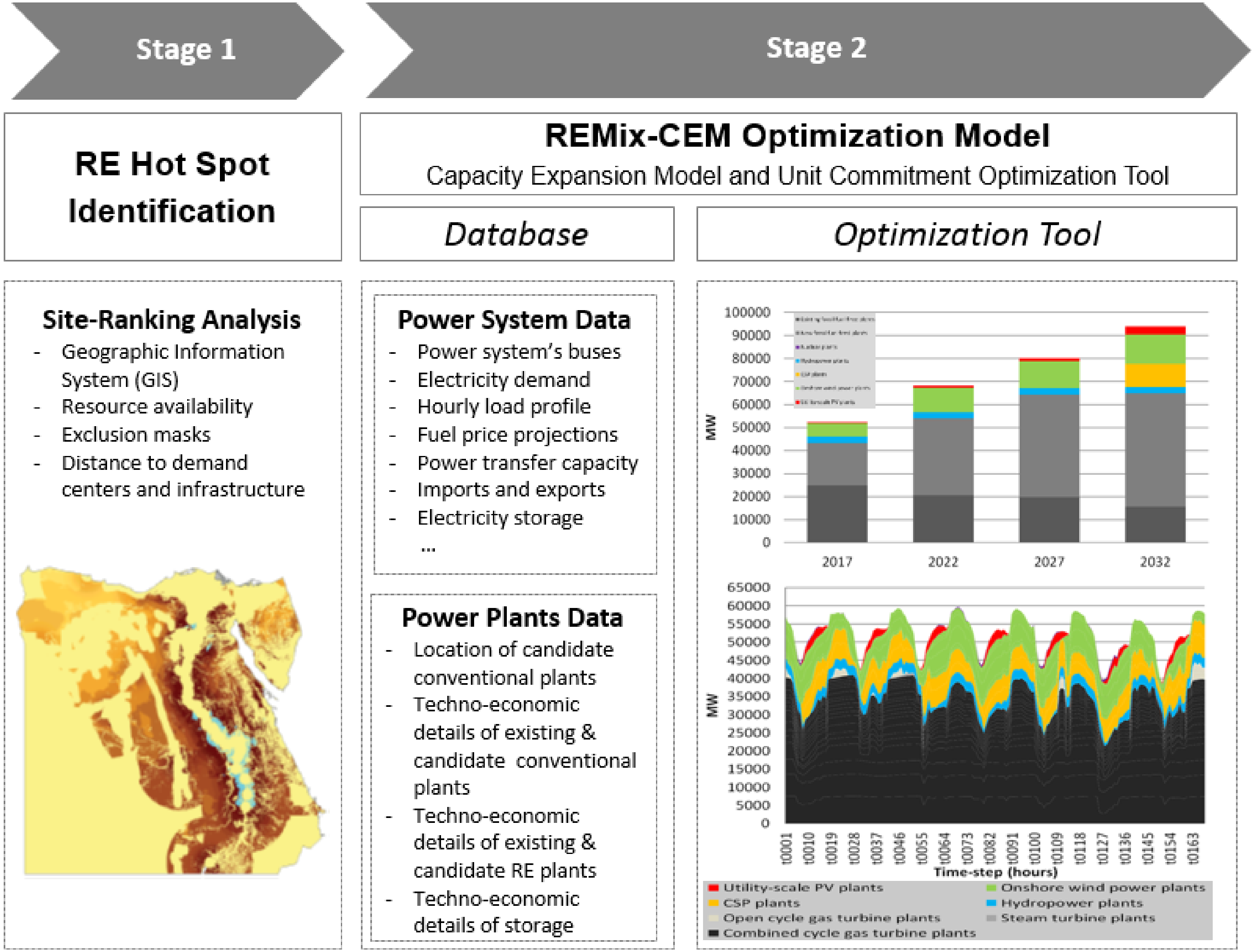

Figure 3.1: Research methodology for optimal integration of RE technologies

3.1 Hot Spots Identification

Egypt located within the Mediterranean and Northern Africa Sunbelt is endowed with fabulous solar resources, the annual global solar insolation is estimated to range from 1750 to 2680 kWh/m2 and the annual direct normal solar irradiance is estimated to range from 1970 to 3200 kWh/m^2, furthermore the daily sunshine duration ranging from 9 to 11 hours with only few cloudy days over the year [43].

Egypt is predominantly desert land and almost all the population is concentrated around the river Nile and on the coastal cities. There is vast vacant desert land throughout the country that has total area of about one million km^2. According to a study conducted by the DLR, the CSP electricity potentials were calculated from the annual DNI with a conversion factor of 0.045 (average annual efficiency of 15% and land use factor of 30% considering state of the art parabolic trough CSP power plants) and the estimated annual economic potential (considering only sites with annual DNI greater than 2000 kWh/m^2) was more than 57,000 TWh [42] .

3.1.1 Solar resource assessment

Egypt has massive solar potential; the average annual values for direct normal irradiation (DNI) and global horizontal irradiation (GHI) for the 15 years period from 1991 to 2005 based on hourly values are shown in figure 3.2 and figure 3.3 . The Solar Energy Mining model (SOLEMI) developed by the DLR [15] has been used to generate the relevant solar resources' maps. It is obvious that Egypt is endowed with fabulous solar resource with annual DNI and GHI values as high as 3100 kWh/m^2 and 2700 kWh/m^2 respectively.

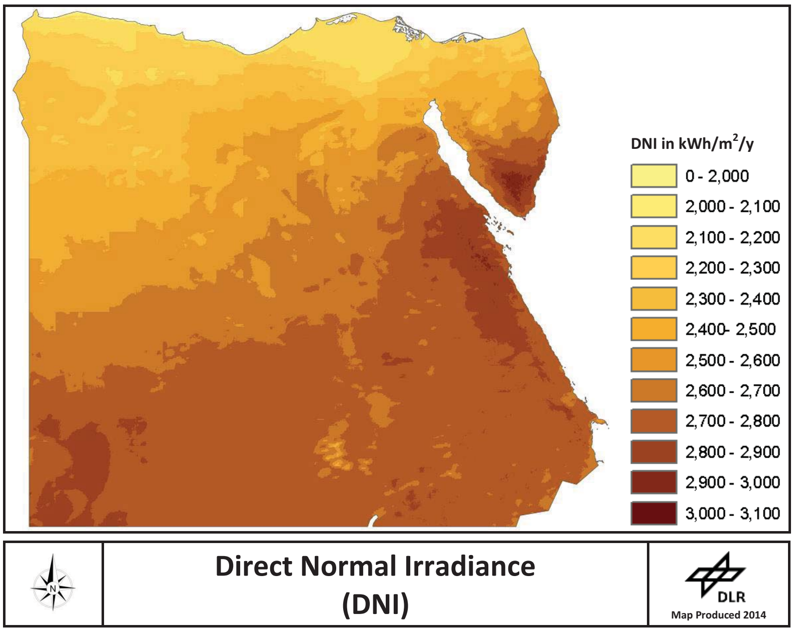

Figure 3.2: DNI annual sum

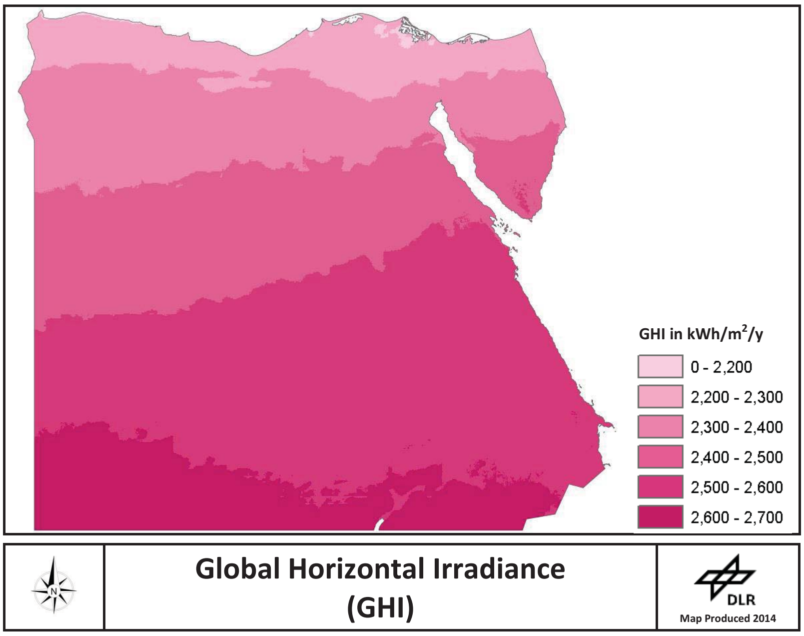

Figure 3.3: GHI annual sum

3.1.2 Land resource assessment

Different exclusion criteria related to topography, land cover, protected areas, urban use, geomorphology, and hydrology have been applied. Such geographic features were derived from remote sensing data and stored in form of GIS maps. The related GIS land exclusion maps has been developed by the DLR within the framework of MENA Regional Water Outlook project that presented comprehensive land exclusion map for CSP in MENA region. The criteria considered for developing exclusion masks include [42]:

- Terrain (i.e. any land with slope greater than 2.1%)
- Land Cover (i.e. post-flooding, irrigated croplands, rain-fed croplands, mosaic cropland and vegetation, shrubland, permanently or regularly flooded areas, and water bodies)
- Protected Areas (i.e. categories IUCN Ia, IUCN Ib, IUCN II, IUCN III, IUCN IV, IUCN V, and IUCN VI)
- Population density (land with population density greater than 50 persons per km^2)
- Geomorphology (i.e. shifting sand -with security zone of 10 km- and dunes)
- Hydrology (i.e. lake, reservoir, river, freshwater marsh, floodplain, coastal wetland, brackish and saline wetland, bog, fen, mire, and intermittent wetland)

Different datasets were used and transferred to a GIS-tool in order to be utilized through the land resource assessment process. Table 3.1 shows some of the used datasets for applied exclusion criteria. Referring to figure 3.4 and figure 3.5, the white coloured areas represent suitable land for constructing CSP plants and utility-scale PV plants respectively (with spatial resolution of approximately 1 km2).

Table 3.1: Used datasets for applied exclusion criteria
Data source: DLR,2011 [42]

Criteria	Map / Data Source	Notes
Terrain	Global Land One-km Base Elevation Digital Elevation Model (GLOBE), and for the determination of the slope (Hastings & Dunbar, 1999) was used.	A slope higher than 2.1% is excluded for the building of CSP plants. The value of 2.1% is determined by the slope-function based on the elevation, the error of the GLOBE-data and the error propagation (Kronshage, 2001).
Land Cover	European Space Agency's (ESA) Globcover Database (Bicheron et al., 2008).	The ESA Globcover map has a spatial resolution of 10 x 10 arc-seconds (~ 300 x 300 m²) and is classified in 23 categories.
Protected Areas	Data provided by The World Conservation Union (IUCN) and the World Commission on Protected Areas (WCPA). Data is taken from (protectedplanet.net).	IUCN has defined a series of six protected area management categories, based on primary management objective. Any land designated under any of those categories is excluded.
Population Density	LandScan Global Population Database (Oak Ridge National Laboratory, 2003).	The spatial resolution of the data set is 30 x 30 arc-seconds (1 x 1 km²).
Urban Expansion	Own map produced.	Circular areas within 20 km from city centres of the most populous 119 Egyptian cities have been excluded.
Geomorphology	Digital Soil Map of the World (DSMW) of the FAO (FAO, 2007). The DSMW is based on the 'Soil Map of the World' (1:5 Mio.) of the FAO/UNESCO from the year 1978.	The spatial resolution of the digital map amounts to approximately 10 x 10 km² (300 arc-sec).
Hydrology	Global Lakes and Wetlands Database - GLWD (Lehner, Döll, 2004). The GLWD consists of three data sets (GLWD 1-3).	For the land resource assessment, the GLWD-3 data set has been used. The spatial resolution of the data set is 30 x 30 seconds.
Far From Demand	Own map produced.	Areas which are more than 160 km far away from city centres have been excluded.
Low DNI	Own map produced.	Areas with annual DNI less than Less than 2000 kWh/m² have been excluded.
Low GHI	Own map produced.	Areas with annual GHI less than Less than 2300 kWh/m² have been excluded.

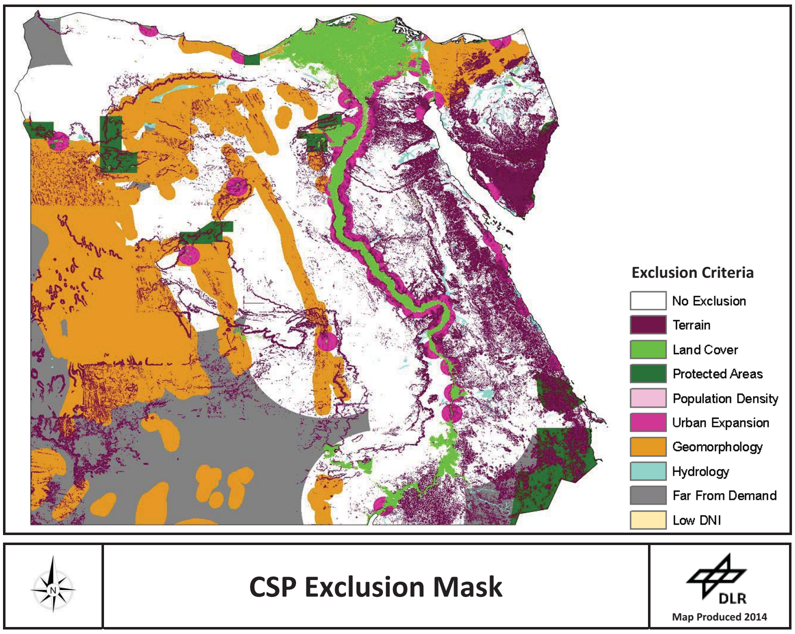

Figure 3.4: CSP exclusion mask

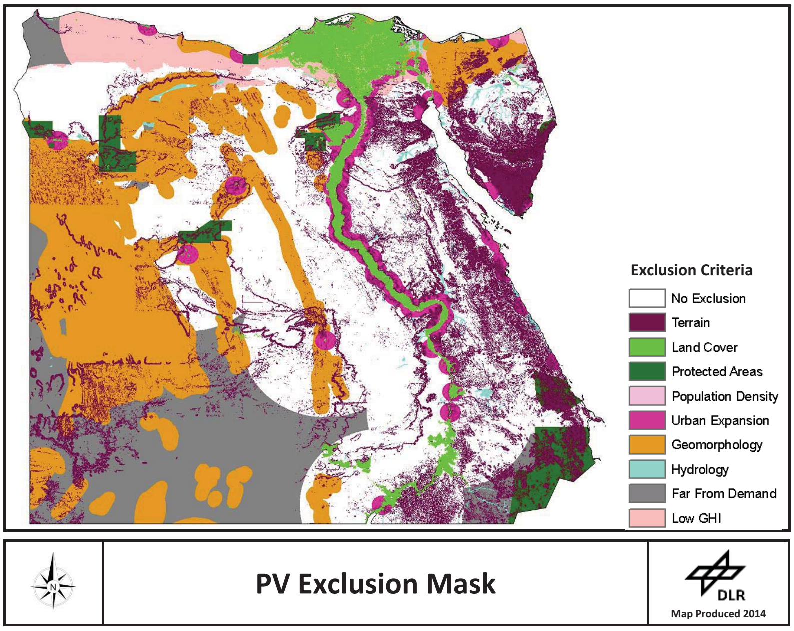

Figure 3.5: PV exclusion mask

3.1.3 Site-ranking process

CSP and PV hot spots identification

The site-ranking process is executed in terms of resource availability, distance to demand centres which in Egypt also inherently represent the existing infrastructure (e.g. transmission lines, substations, major streets). According to World Population Review (WPR), Egypt has 3 cities with population over 1 million (i.e. Cairo, Giza, and Alexandria), 34 cities with population between 100 thousand and 1 million, and 86 cities with population between 10 thousand and 100 thousand [7], figure 3.6 shows overview of the cities' location. Such cities are considered to be the main demand centres as most of the people live there and they are the locations where the industries are concentrated as well. Comparing figure 3.6 to figure 2.6 that shows the national unified electricity grid, it is obvious that the electricity grid's routes and the locations of the existing substations are highly linked to the highlighted cities.

For the sake of the site-ranking analysis, Egypt's territory is divided into 1-km^2 pixels and each pixel is valued with respect to the specified criteria. Table 3.2 shows the respective weighing values for each criterion.

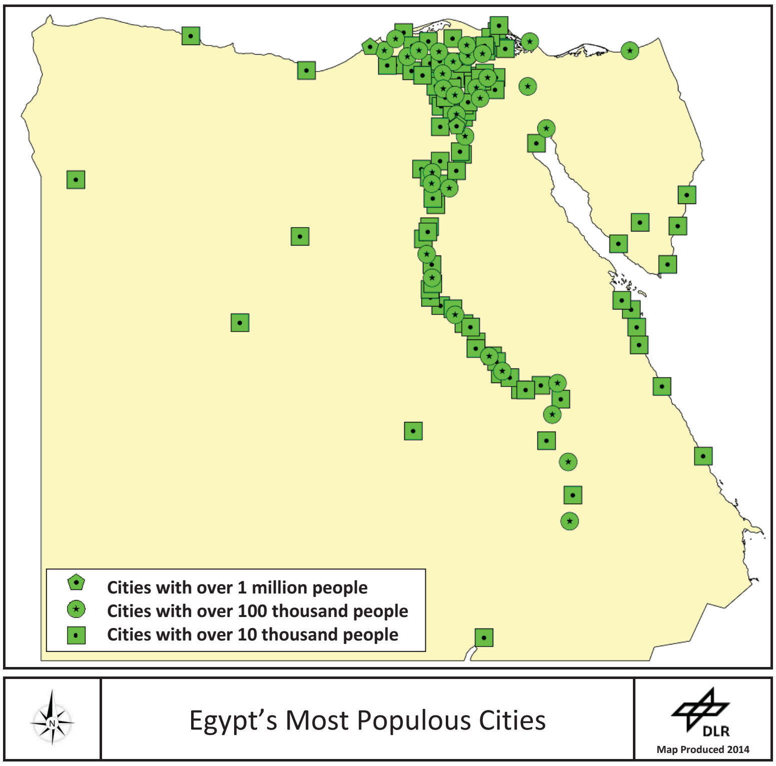

Figure 3.6: Egypt's most populous cities
Data source: World Population Review, 2014 [7]

After adding up the values for each criterion, the CSP overall ranking map has been developed and it is shown in figure 3.7. Finally the CSP overall ranking map has been combined with an exclusion mask map that excluded land which is not suitable for constructing CSP plants, and this resulted in CSP final ranking map shown in figure 3.8. Figure 3.9 highlights the most promising sites for installing CSP plants, those sites are corresponding to the pixels with the highest 10% CSP final ranking values.

Three hot spots for future CSP plants has been identified in west Kom-Ombo, east Qena, and west Asiut. Figure 3.10 shows the hourly DNI around the year for the three identified CSP hot spots.

Similarly the PV overall ranking map has been developed and it is shown in figure 3.11. Finally the PV overall ranking map has been combined with an exclusion mask map that excluded land which is not suitable for constructing PV plants, and this resulted in PV final ranking

Table 3.2: Values and weighing for CSP and utility-scale PV site-ranking

Solar resource potential ranking				Demand centres ranking					
DNI		GHI		Cities over 1 m		Cities between 100 k and 1 m		Cities between 10 k and 100 k	
Tiers [kWh/m^2/y]	Value	Tiers [kWh/m^2/y]	Value	Distance [km]	Value	Distance [km]	Value	Distance [km]	Value
2000-2100	15	2300-2350	20	20-40	40	20-40	35	20-30	25
2100-2200	30	2350-2400	40	40-80	35	40-60	30	30-40	23
2200-2300	45	2400-2450	60	80-120	20	60-80	23	40-50	20
2300-2400	60	2450-2500	80	120-160	10	80-100	15	50-60	10
2400-2500	75	2500-2550	100	>160	0	100-120	5	60-70	5
2500-2600	90	2550-2600	120			>120	0	70-80	2
2600-2700	105	2600-2650	140					>80	0
2700-2800	120	2650-2700	160						
2800-2900	135								
2900-3000	150								
3000-3100	165								

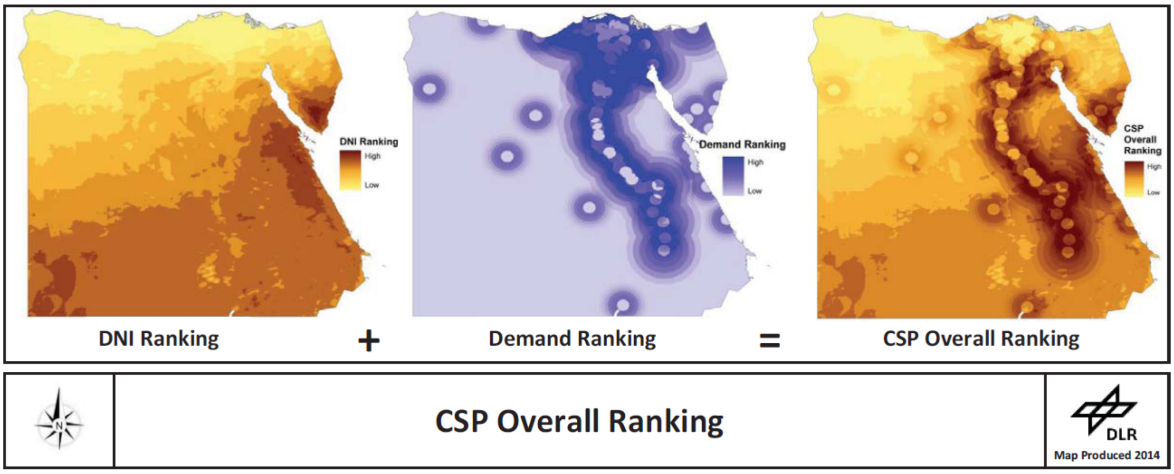

Figure 3.7: CSP overall ranking, includes DNI ranking and demand ranking

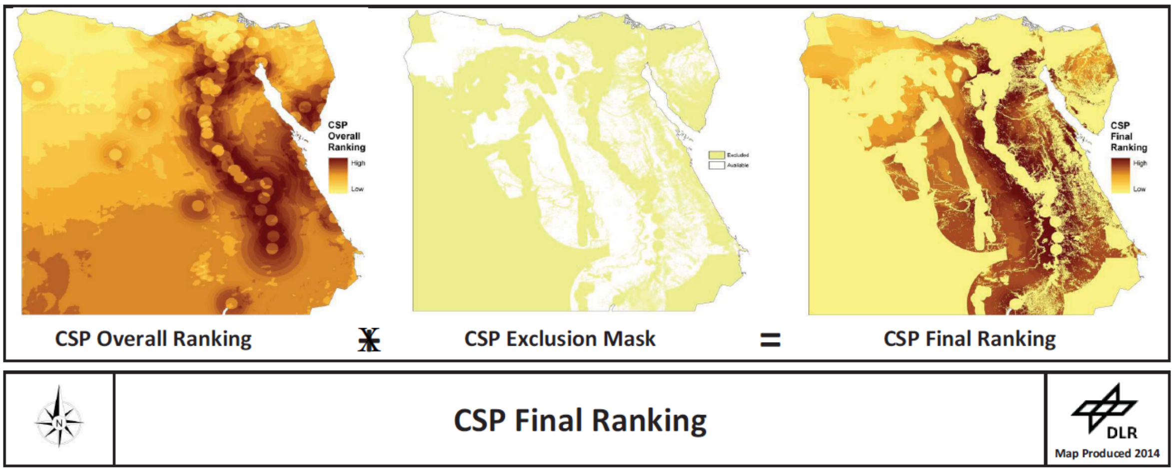

Figure 3.8: CSP final ranking, includes CSP overall ranking and CSP exclusion mask

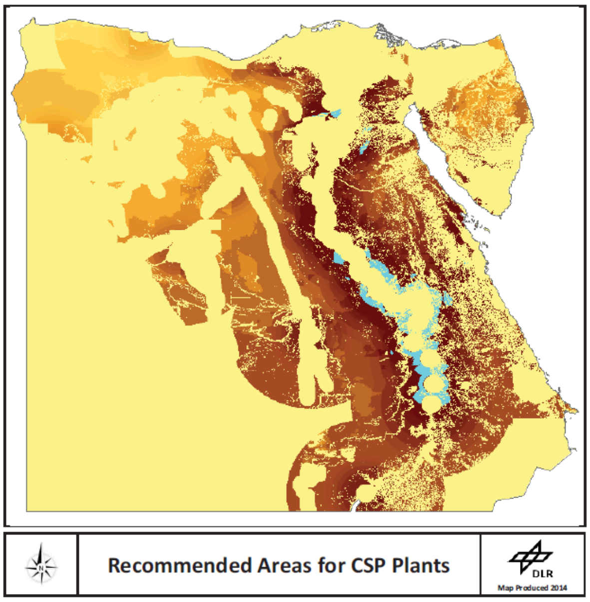

Figure 3.9: CSP most promising sites

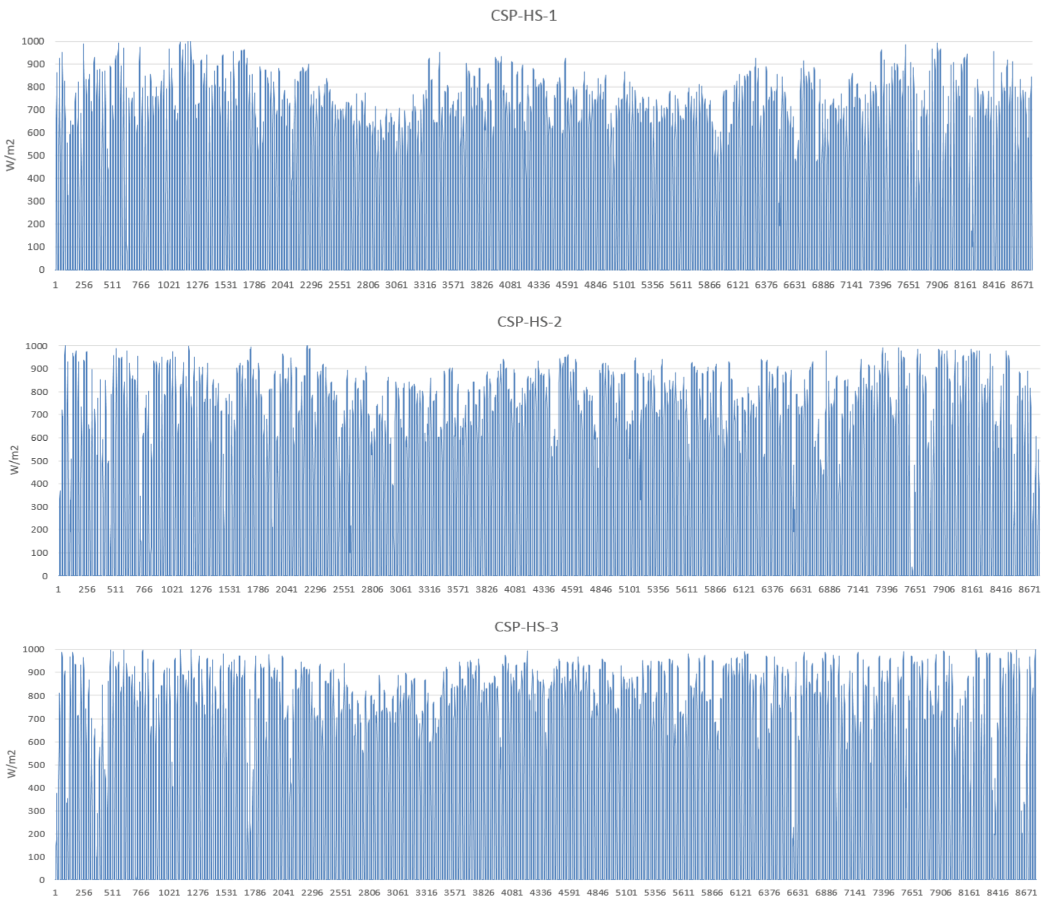

Figure 3.10: Hourly DNI around the year for the three identified CSP hot spots
Data source: Meteonorm [14]

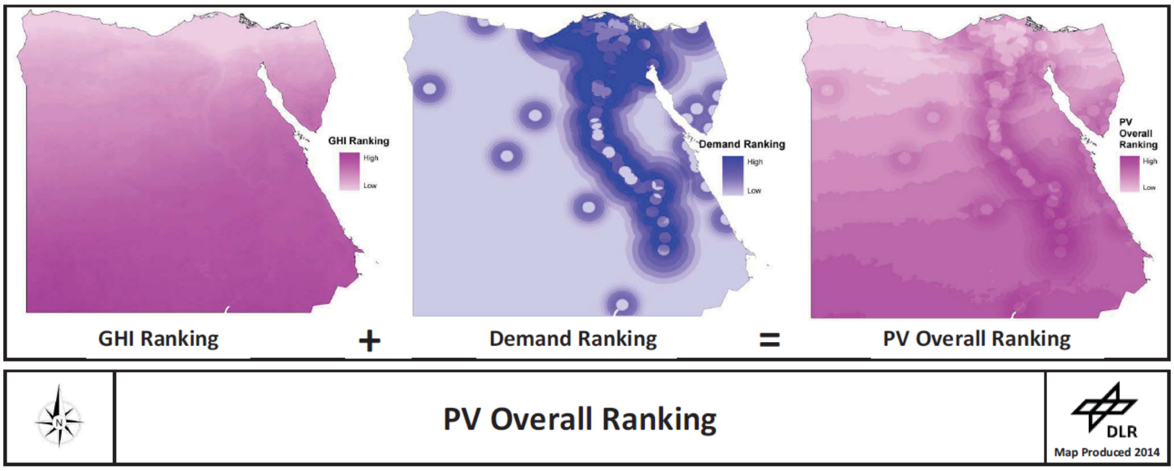

Figure 3.11: PV overall ranking, includes GHI ranking and demand ranking

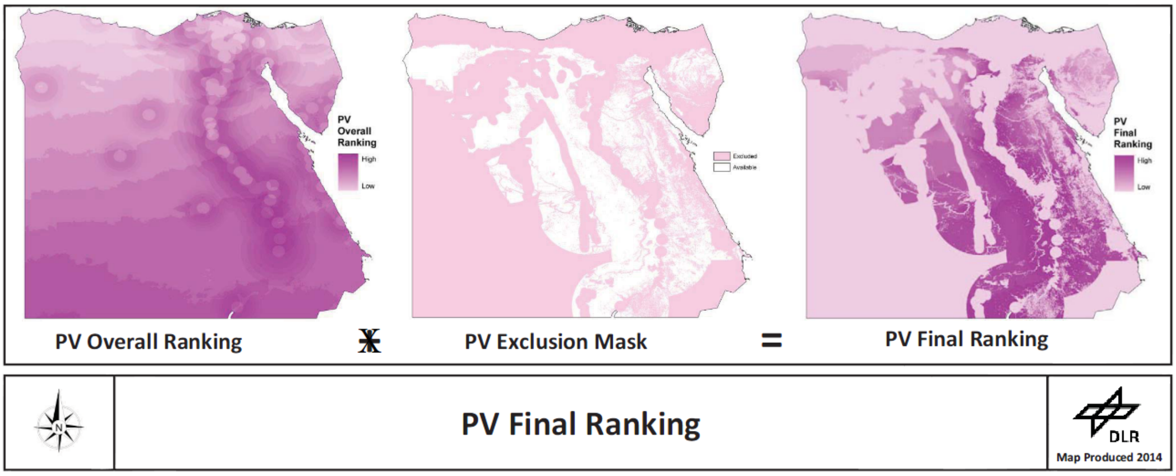

Figure 3.12: PV final ranking, includes PV overall rank and PV exclusion mask

map shown in figure 3.12. Figure 3.13 highlights the most promising sites for installing PV plants, those sites are corresponding to the pixels with the highest 10% PV final ranking values. Three hot spots for future PV plants has been identified in east Kom-Ombo, west Nagaa El-Hamam, and west Nagaa El-Shaikh. Figure 3.14 shows the hourly GHI around the year for the three identified PV hot spots.

Onshore wind hot spots identification

Egypt is not only endowed by enormous solar resources, but with significant potential of onshore wind as well. The wind resource in Egypt has been well investigated as Risoe National Laboratory (Denmark) had

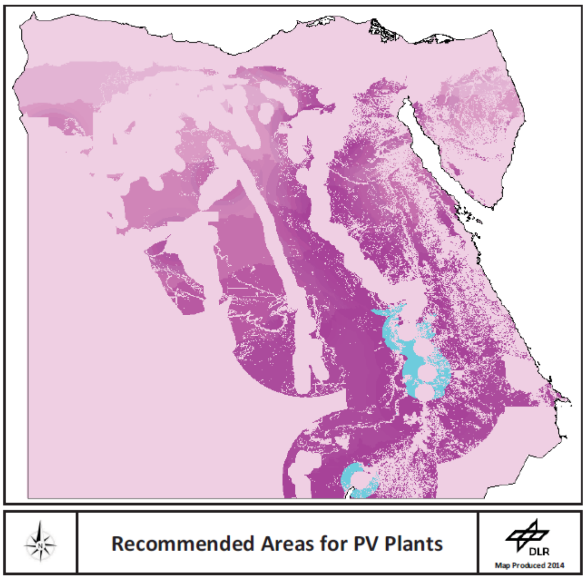

Figure 3.13: PV most promising sites

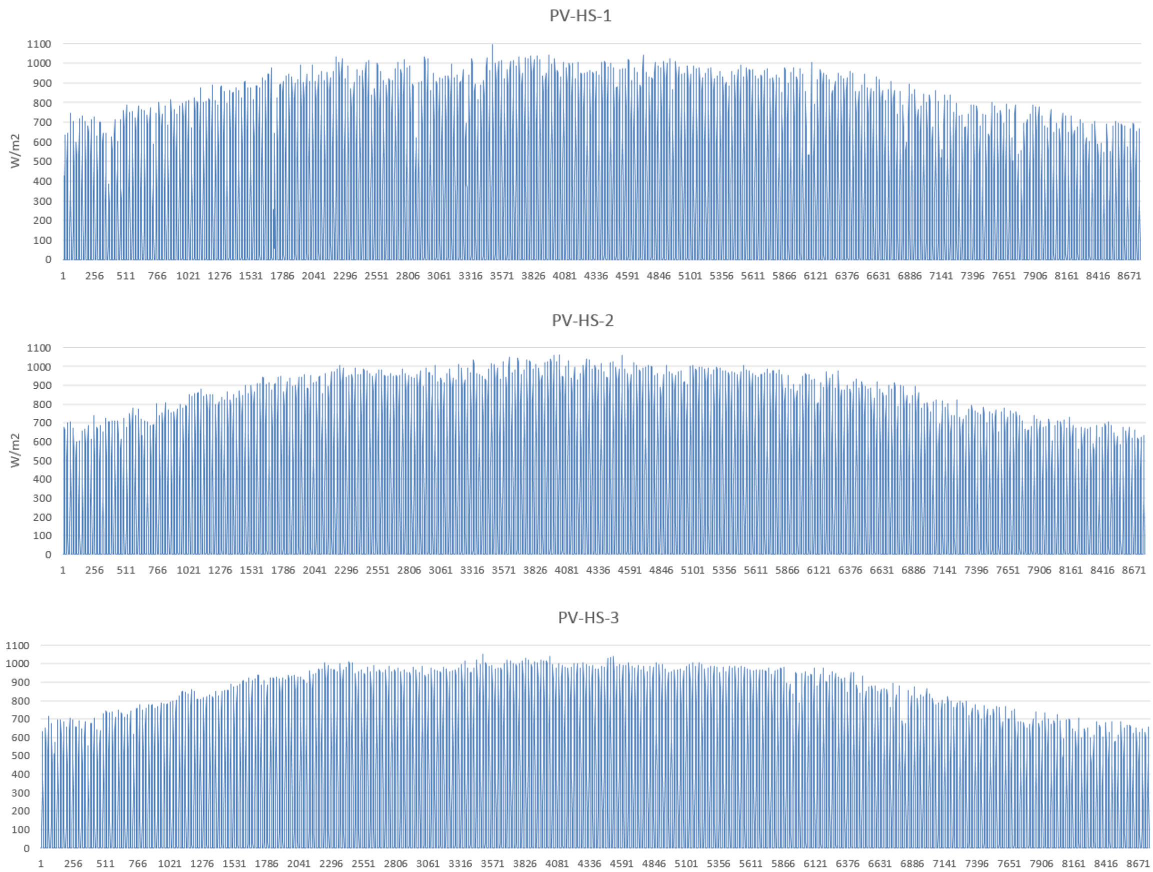

Figure 3.14: Hourly GHI around the year for the three identified PV hot spots
Data source: Meteonorm [14]

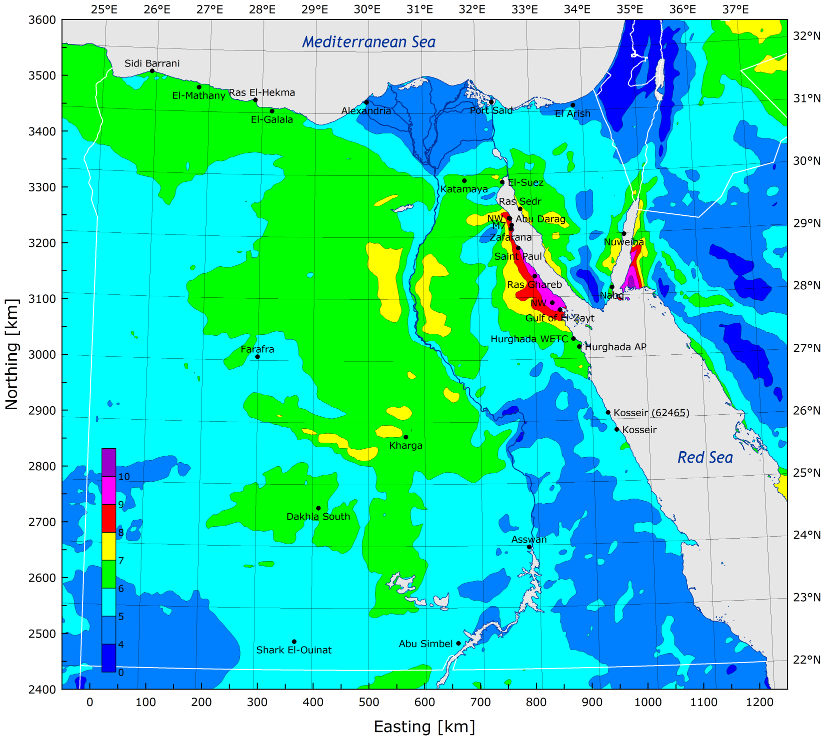

Figure 3.15: Egypt's wind atlas
Source: Risoe National Laboratory [32]

conducted a comprehensive 8-year wind resource assessment program in Egypt with the aim to advance reliable and accurate wind power resource assessment through developing comprehensive wind atlas which is shown in figure 3.15 (legend colours show mean wind speeds in [m/s] at 50 m height).

Such wind power resource assessment concluded very high wind resource in the Gulfs of Suez and Aqaba, in addition to a large region in the Western Desert with a fairly high resource and with added-advantage of being close to load centres and the utility grid [32]. Hence the previously described resources assessment and site ranking methodology was not followed for onshore wind hot spots identification. Instead, the most promising identified sites by Risoe National Laboratory have been considered as the hot spots. Such way of identifying the hot spots seems to be more realistic given the maturity of the wind power resources assessment in Egypt and the government clear plans about the wind power expansion plans, consequently areas with the highest wind potential has

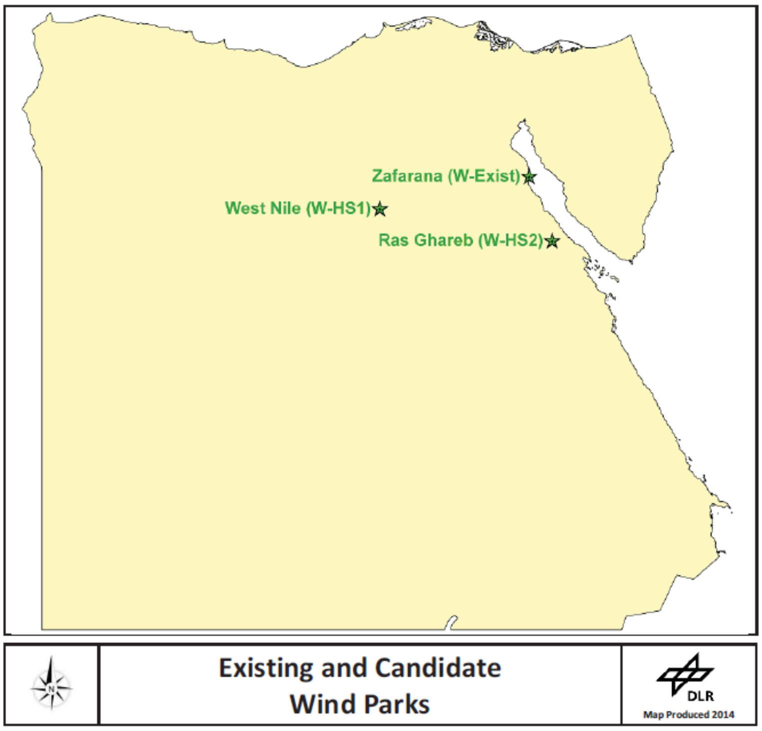

Figure 3.16: Wind power hot spots

been allocated for wind projects (i.e. areas total more than 1,400 km^2 in the West Coast of the Gulf of Suez and total more than 6,400 km^2 in east and west of the Nile river has been allocated [4]). The location of the existing wind park at Zafarana, and the location of the two identified onshore wind hot spots at Ras Ghareb and West Nile (north of Minya governorate) are shown in figure 3.16.

The hourly wind speed at 10 metres height the three hot spots have been obtained from Meteonorm and then scaled up to estimate the wind speed at 50 metres height. For Zafarana site, the annual mean wind speed was calculated as 7.36 m/s at 50 metres height, which is quite low compared to the wind atlas value that indicate 8.85 m/s in the same location and at the same height. So the calculated hourly wind speed at 50 metres height has been corrected to reach the same annual mean wind speed stated in the wind atlas, and this values -when processed through the wind model- led to a capacity factor of 40.3% which is very reasonable as the actual electricity production from Zafarana is quoted to have capacity factor of 40.6% [26]. Figure 3.17 shows the corrected

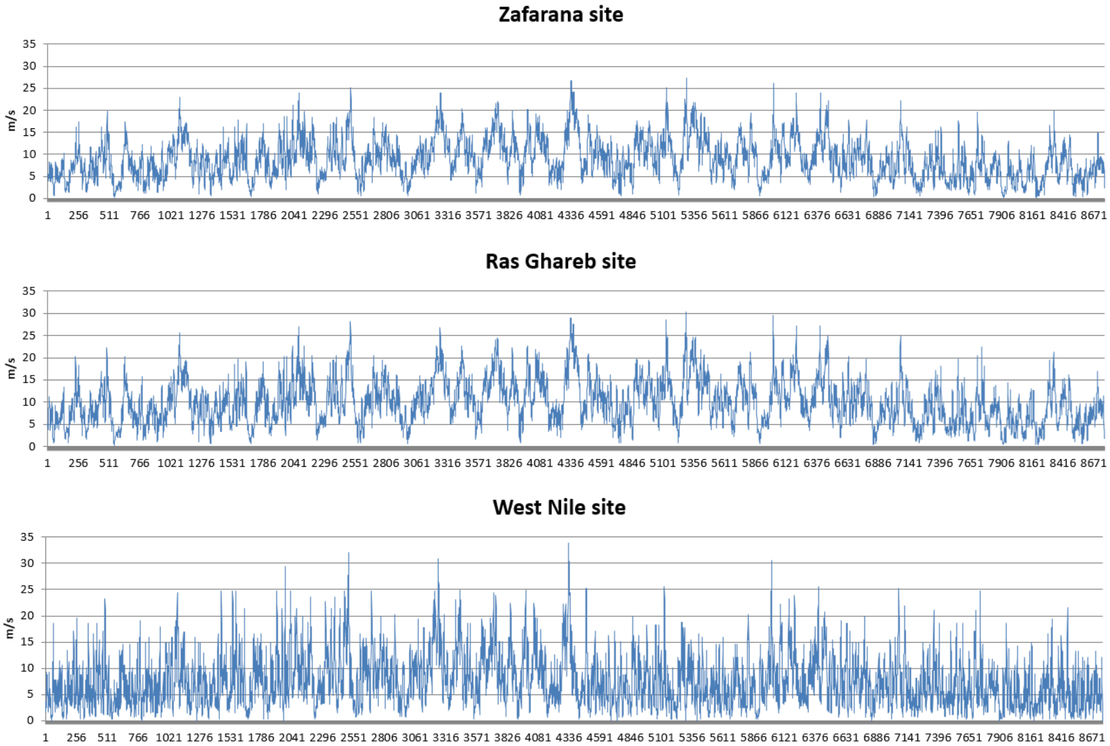

Figure 3.17: Corrected hourly wind speed at 50m height

hourly wind speed at 50 metres height for Zafarana site, besides the two identified sites for future onshore wind power projects.

To verify the intern-annual (monthly) pattern of wind speed values obtained from Meteonorm (see figure 3.18), the monthly mean wind speed at 10 meters height obtained from Meteonorm for Ras Ghareb site was compared to the monthly mean wind speed at 10 meters height calculated from measured wind speed (i.e. the wind speed at Ras Ghareb has been recorded at 24.5 meters height for 6-year period from 2000 to 2005 by NREA [17]).

3.1.4 Identified RE technology-specific hot spots

Table 3.3 shows an overview of the identified technology-specific hot spots, while figure 3.19 shows the location of the different technology-specific hot spots in a single map.

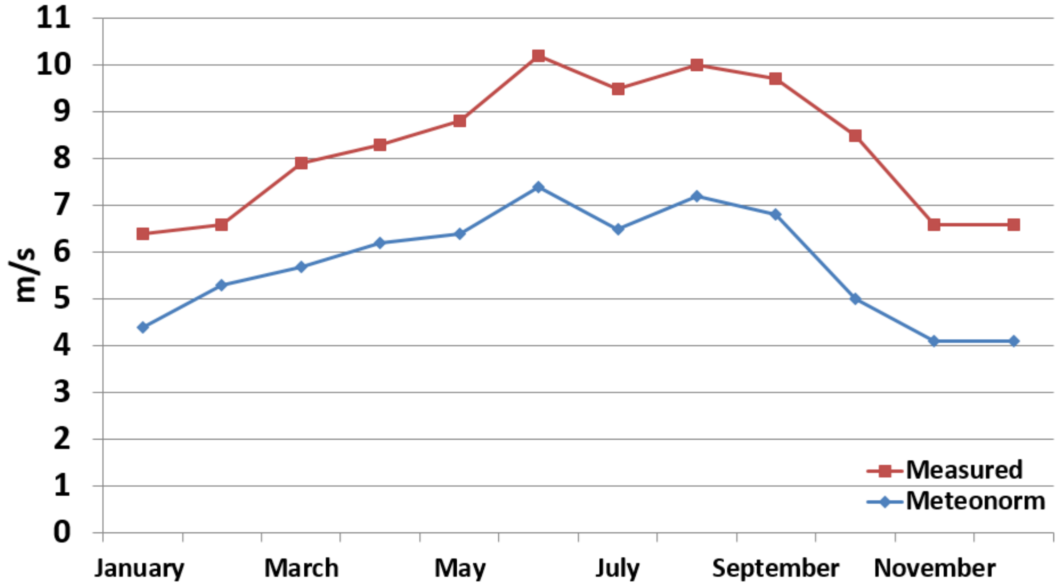

Figure 3.18: Monthly mean wind speed at 10m height at Ras Ghareb site
Data source: Meteonorm [14] and Shata, 2011 [17]

Table 3.3: Identified RE technology-specific hot spots

Hot spots	Location	Resource	Mean ambient temperature
CSP-1	west Kom-Ombo	DNI: 2747 kWh/m^2/year	27 °C
CSP-2	east Qena	DNI: 2798 kWh/m^2/year	25 °C
CSP-3	west Asiut	DNI: 2726 kWh/m^2/year	23 °C
PV-1	east Kom-Ombo	GHI: 2567 kWh/m^2/year	27 °C
PV-2	west Nagaa El-Hamam	GHI: 2560 kWh/m^2/year	26 °C
PV-3	west Nagaa El-Shaikh	GHI: 2553 kWh/m^2/year	25 °C
Wind-1	west Nile (Minya)	Wind speed at 50m: 7.5 m/s	22 °C
Wind-2	Ras Ghareb	Wind speed at 50m: 10 m/s	23 °C

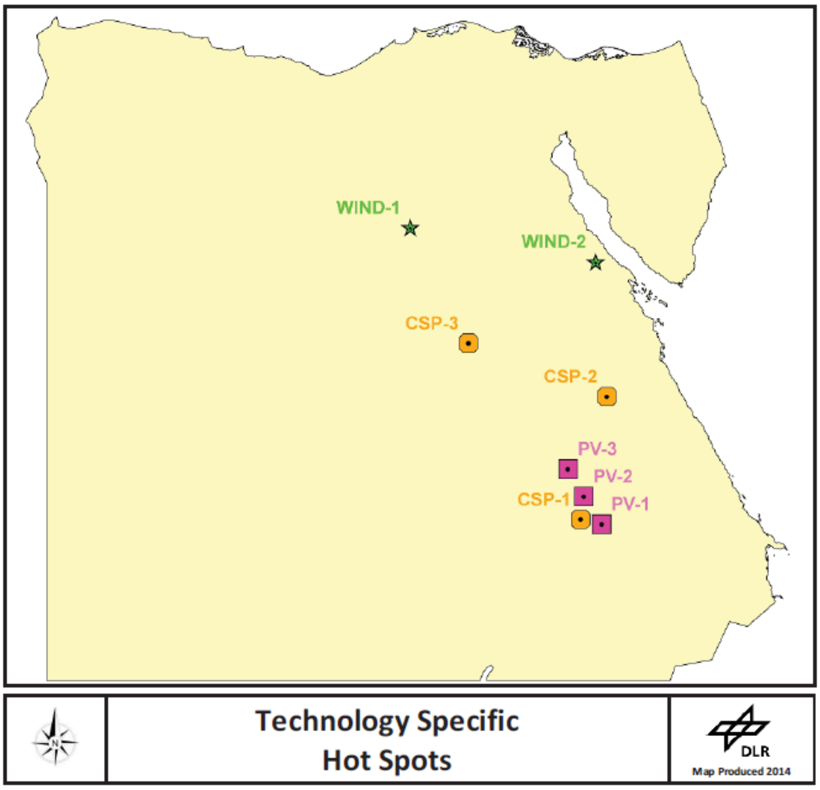

Figure 3.19: Identified RE technology-specific hot spots

3.2 REMix-CEM Optimization Model

Capacity expansion is optimized from a state-owned utility perspective in 5-year planning steps taking into account the existing power plant portfolio. The planning horizon is extended until year 2032, hence the analysis covered four 5-year planning steps from 2017 through 2032 which are collectively optimized in a dynamic way; this means that the four planning step are optimized at once, resulting in an optimal pathway for capacity expansion until 2032.

3.2.1 Optimization model's input database sets

There are two main database sets which represent the inputs to the REMix-CEM optimization model, namely:

- Power system related databases
- Power plants related databases

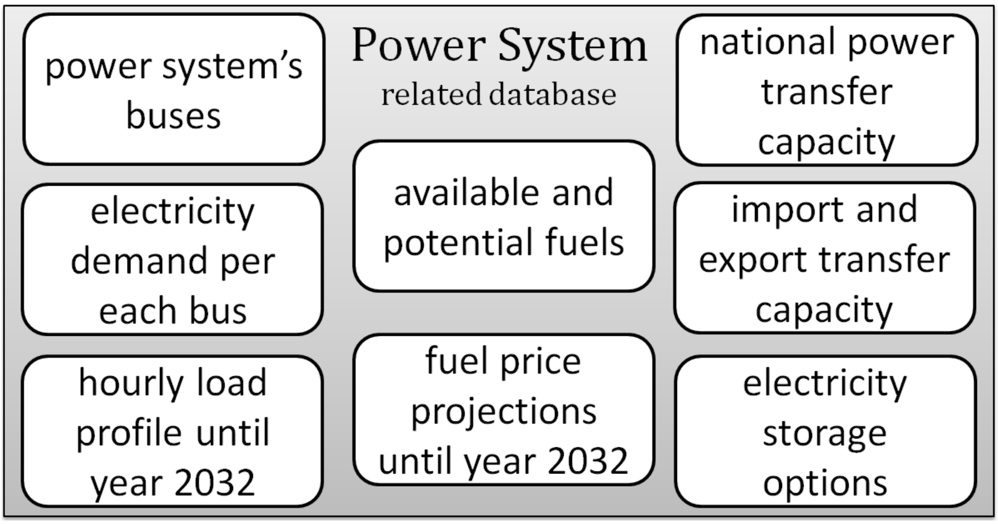

Figure 3.20: Power system related database sets

The databases provide the model with all the required data and constrains related to the power system in question and thus enable the model to select the optimum generation expansion plan that minimize the total system cost while ensure the security of supply.

Power system related databases

Figure 3.20 shows the different database sets used to represent the power system.

Power system's buses

Power system's buses are the zones that could be considered autonomous and is connected to the whole power system through interconnection nodes. The Egyptian power system was divided into five buses according to the geographical coverage of the five electricity generation companies. Referring to figure 3.21, bus 1 represents Cairo Generation Company (covering Greater Cairo), bus 2 represents Middle Delta Generation Company (covering Al-Qalyubiyah and Ad-Daqahliyah governorates), bus 3 represents West Delta Generation Company (covering Al-Buhayrah, Al-Iskandriyah, and Marsa Matruh governorates), bus 4 represents East Delta Generation Company (covering Dumyat, Al-Isa'iliyah, Bur Sa'id, As-Suways, Janum-Sina', Shamal-Sina', and Al-

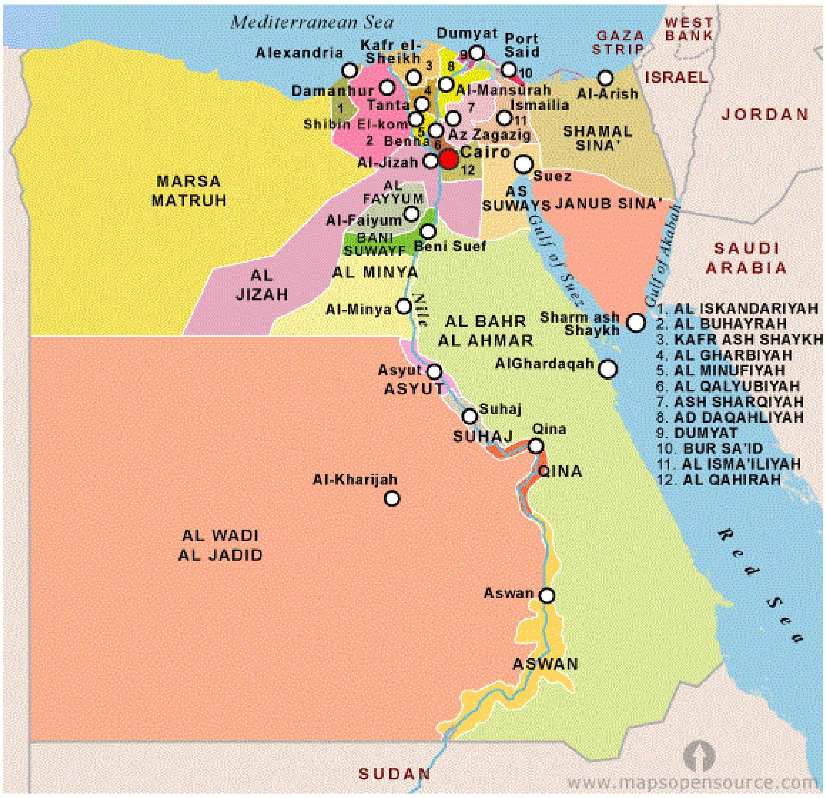

Figure 3.21: Egypt governorates map

Bahr Al-Ahmar governorates), bus 5 represents Upper Egypt Generation Company (covering Al-Jizah, Al-Faiyum, Bani-Suwayf, Al-Minya, Asyut, Al-Wadi Al-Jadid, Suhaj, Qina , Aswan, and Luxor governorates). Each power plant either existing or candidate is associated to the bus where it is (or it could be) physically located.

Electricity demand per each bus

The electricity demand for each bus has been estimated according to the latest updated data available from EEHC [2]. The total number of customers reached a bit more than 28 million in 2012 with total consumption of 157 TWh. As there is nine electricity distribution companies in Egypt, in contrast to only five defined buses associated to the five electricity generation companies, table 3.4 shows how the electricity demand per each bus has been estimated using the number of customers supplied by each of the distribution companies. Table 3.4 shows also the demand percentage of each bus, which is very realistic in terms of the population and industries which are supplied within each bus, that explain that

Table 3.4: Estimating the electricity demand per each bus

Bus number	Relevant distribution company	Number of customers [in million]	Total number of customers [in million]	Consumption (TWh)	Percentage of electricity demand
Bus 1	North Cairo South Cairo South Delta	3.76 4.70 3.64	12.10	67,7	43 %
Bus 2	North Delta	3.30	3.301	18,5	12 %
Bus 3	El-Behera Alexandria	1.81 2.21	4.02	22,5	14%
Bus 4	Canal	3.17	3.17	17,7	11%
Bus 5	Middle Egypt Upper Egypt	3.04 2.43	5.47	30,6	20%

bus 1 (covering Greater Cairo) represents 43% of the total demand (i.e. where most of the population and industries are located). The population and industries are assumed to grow proportionally according to the current geographical segmentation, so the stated percentage of electricity demand per each bus is expected to be stable within the years to come.

Hourly load profile until year 2032

Population, income, and efficiency of supply are the three main factors that drive future electricity demand. While flourishing economy and growing population would lead onto increasing future demand, more efficient supply shall limit such growing demand. The used load estimate is based on a detailed study conducted by the DLR [41]. The gross power demand development until the year 2032 was taken from two previous studied conducted by the DLR [39, 40]. Such gross power demand was estimated based on regression analyses of historical power demand and the development of the gross domestic product (GDP). Looking at the past decade, the electricity consumption in Egypt was increasing by an annual average of approximately 6.6 TWh, if this trend would continue in the future, this will lead to consumption of 200 TWh/y by 2020 and 400 TWh/y by 2050. The official national forecast (according to Arab Union of Electricity) estimate a demand of almost 300 TWh/y by 2020,

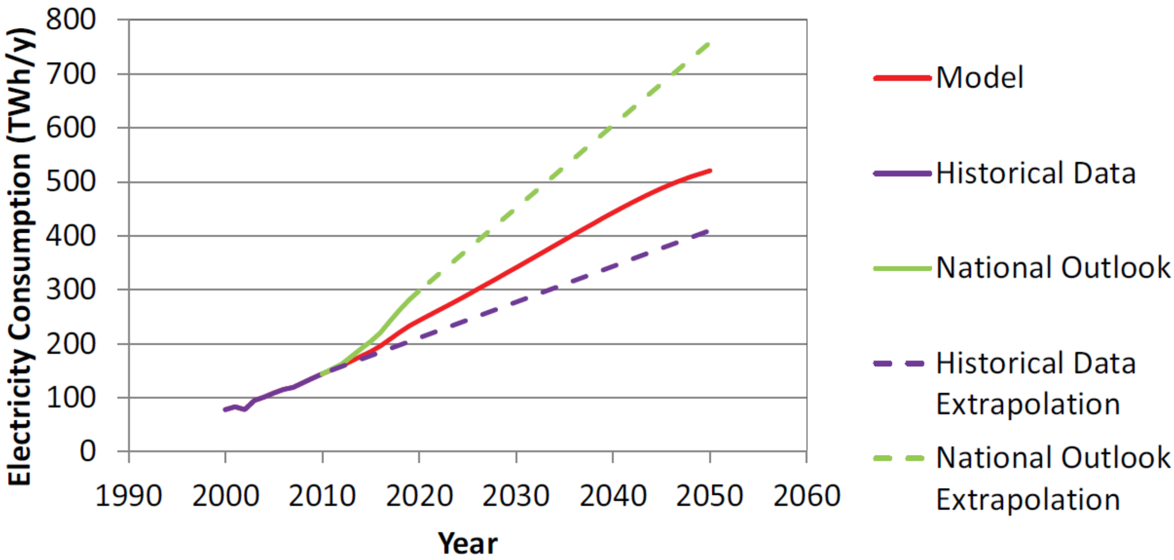

Figure 3.22: Egypt's future electricity demand estimates
Data source: DLR [41]

if this forecast has been extrapolated linearly after 2020 then Egypt shall consume about 750 TWh in 2050 [41]. Referring to figure 3.22, the model used in the DLR study indicates something in the middle, estimating electricity consumption of about 520 TWh in 2050.

In the context of the DLR study, the historical data on Egypt's hourly time series (i.e. hourly load curve) for the entire year of 2010 was provided by Arab Union of Electricity, such load curve was scaled up for all consecutive years until 2032. It is worth mentioning that the estimated hourly load profile for each single year from year 2017 until year 2032 has been introduced as an input to the REMix-CEM model. Figure 3.23 shows the estimated hourly load profile for some selected years.

Available and potential fuels

The currently available and candidate fuels have been identified and their cost projections from year 2017 through year 2032 have been introduced to the model. The currently used fuels for electricity generation in Egypt are natural gas and oil (HFO and LFO), and the government has some plans for using coal and nuclear fuels in the future [8].

Fuel price projections until year 2032

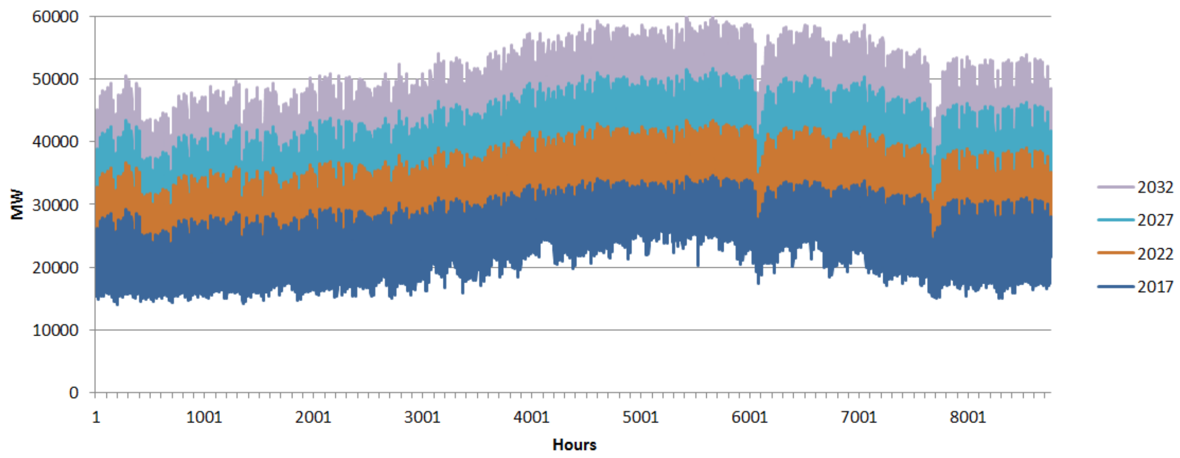

Figure 3.23: Estimated hourly load profile for selected years

Table 3.5: Initial fuel price
Data source: [6, 9, 11, 36, 45]

Fuel	International market price*	Source	Price in [EUR/MWh$_{th}$]
LFO	**0.74** EUR/litre	Dubai Fateh crude oil price of 102 USD/Barrel, August 2014	54.3
HFO	**512** EUR/tonne	International prices of imported HFO (Rotterdam), August 2014	44.0
Natural Gas	**7.93** EUR/MMBtu	European Union natural gas import price of 9.14 USD/MMBtu, August 2014	27.0
Coal	**114** EUR/tonne	South Valley Cement import price of 5.2 USD/MMBtu (transportation included), April 2014	14.0
Nuclear	**7.4** EUR/MWh	Costs of the nuclear fuel cycle (includes Front-end and Back-end cycles) of 9.33 USD/MWh	7.4

* International market price includes estimated transportation cost of 10% for natural gas, LFO, and HFO
** Currency conversion factor; 1 EUR = 1.27 USD

Referring to section 2.1.5, there is a strong argument that the price of fossil fuels used for electricity generation in Egypt will reach the international market price in the near future in the light of the sweeping measures to increase energy prices that have been introduced in July 2014. Table 3.5 shows the assumed fuel price in beginning of 2015, then figure 3.24 shows the projections of the fuel prices according to the mid-escalation scenario (i.e. 2% annual escalation rate).

National power transfer capacity

To identify the existing national power transfer capacity among different buses through corresponding nodes, the national unified electricity

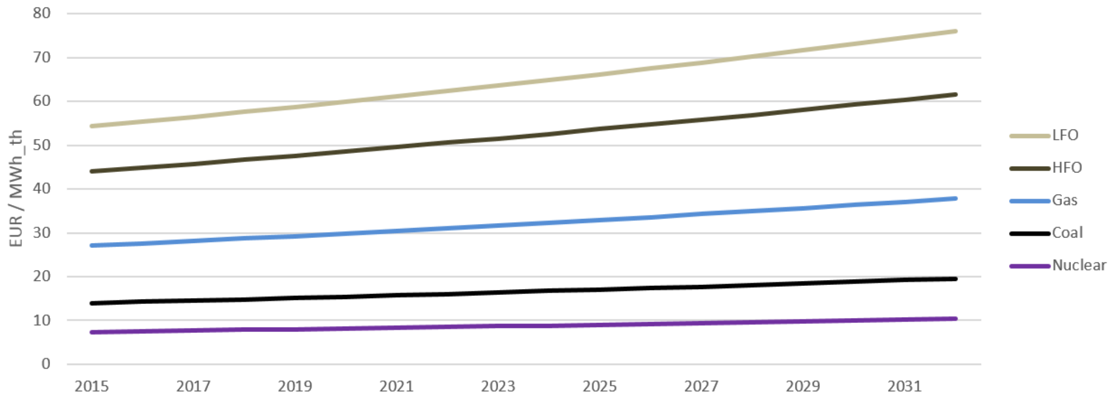

Figure 3.24: Fuel price projections according to the mid-escalation scenario

grid shown in figure 2.6 has been used. To determine the maximum allowable power flow of a high-voltage transmission line, there are many considerations to be taken into account such as thermal limit, voltage drop limit, and Surge Impedance Loading (SIL) limit. The power flow of the very long transmission lines (exceeding 250 km) should be limited to the SIL, while the thermal limit and voltage drop limit play important role in determining the maximum power flow of the shorter transmission lines (less than 250 km).

The high-voltage power transmission levels considered in this context are the 500 kV and 220 kV transmission lines. While almost all the 500 kV lines are very long (exceeding 250 km; connecting Upper Egypt with Cairo, and Cairo with Sinai Peninsula), almost all the 220 kV lines are less than 250 km long. So according to the figures of an American engineering consulting firm specialized in designing high-voltage overhead lines [16], the maximum transferable power on 500 kV transmission lines has been estimated to be 880 MW while the maximum transferable power on 220 kV transmission lines has been estimated to be 300 MW. Table 3.6 shows the maximum transferable power between different buses.

Import and export transfer capacity

Egypt transnational interconnection has been shown in table 2.2 that concluded power transfer capacity (either importing or exporting) of 550 MW with Jordan and 240 MW with Libya.

Table 3.6: National power transfer capacity

Node X	Node Y	Transmission lines	Maximum transferable power (MW)
BUS-1	BUS-2	1 no. 500 kV line 2 no. 220 kV line	1480
	BUS-3	1 no. 220 kV line	300
	BUS-4	2 no. 500 kV line 3 no. 220 kV line	2660
	BUS-5	2 no. 500 kV line 1 no. 220 kV line	2060
BUS-2	BUS-3	3 no. 220 kV line	900
	BUS-4	3 no. 220 kV line	900
BUS-4	BUS-5	1 no. 500 kV line 1 no. 220 kV line	1180

Table 3.7: Power system data

	Unit	2017	2022	2027	2032
Total demand	TWh	210	264	311	361
Peak load	GW	34.6	43.4	51.6	60.0
Required firm capacity (peak load + 15% security reserve)	GW	43.3	54.3	64.5	75.0
Existing firm capacity	GW	27.3	22.9	22.1	18.1
Firm capacity shortage	GW	16.0	31.4	42.4	56.9
Fuel prices (2% annual escalation)					
LFO	EUR/MWh$_{th}$	56.5	62.4	68.9	76.0
HFO	EUR/MWh$_{th}$	45.8	50.5	55.8	61.6
Natural Gas	EUR/MWh$_{th}$	28.1	31.0	34.3	37.8
Coal	EUR/MWh$_{th}$	14.5	16.1	17.7	19.6
Nuclear	EUR/MWh$_{th}$	7.7	8.5	9.4	10.4

Electricity storage options

There is no current electricity storage facilities in Egypt and there is no official plans for considering to build such facilities, so electricity storage options have not been considered in the scope of this study.

Table 3.7 summarizes some important information related to the Egyptian power system.

Power plants related databases

Figure 3.25 shows the different database sets used to represent the power plant portfolio.

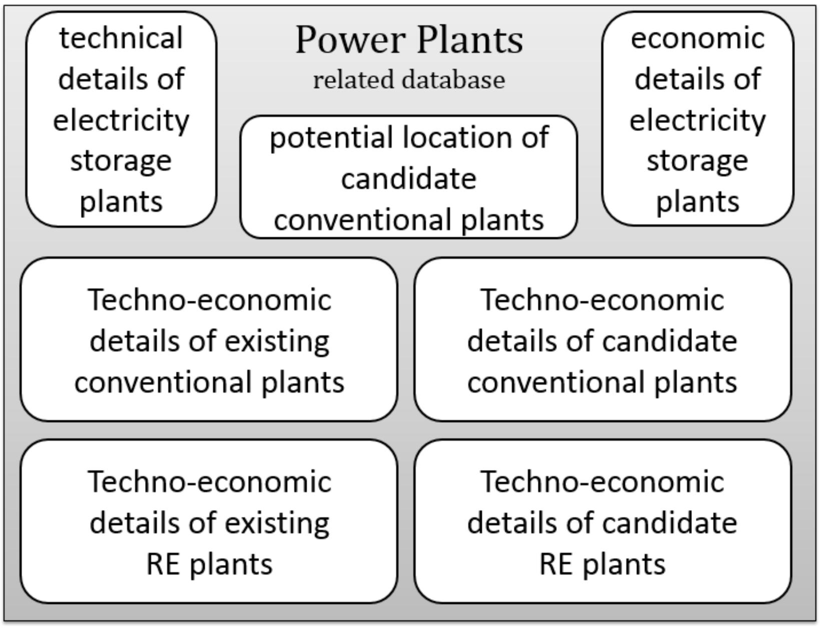

Figure 3.25: Power plants related database sets

Table 3.8: Buses and hot spots associated to the candidate conventional plants

Hot spots of candidate conventional plants	Location	Latitude	Longitude
BUS-1-HS-1	North Giza	30.249	30.947
BUS-2-HS-1	Banha	30.464	31.187
BUS-3-HS-1	Abu Qir	31.313	30.051
BUS-4-HS-1	West Damietta	31.426	31.823
BUS-5-HS-1	Dairout	27.546	30.807

Potential location of candidate conventional plants

A single hot spot has been identified in each bus as a potential location for candidate conventional (fossil fuel fired) plants. Those hot spots were determined in accordance to the locations announced in the official generation expansion plan shown in table 2.6. Table 3.8 shows the buses and hot spots (HS) associated to the candidate conventional plants.

Techno-economic details of existing conventional plants

Many technical details have been included to describe the characteristics and the performance of the existing conventional plants; table 3.9

shows just few of those details. The existing conventional power plant portfolio consists of steam turbines (ST), combined cycle gas turbine (CCGT), and open cycle gas turbine (GT) power plants. It is worth mentioning that all the existing power plants are assumed to have low flexibility (refer to table 3.11), and to have operational lifetime of 35 years. In 2012, there were a total of 132 conventional generation units with total gross capacity of about 26 GW [2].

Many economic details has been included to describe different associated costs of the existing conventional plants that include capital costs, operation and maintenance costs, start-up cost, shut-down cost, and ramping cost. It is worth mentioning that most of the power plant projects in Egypt (according to [1]) had been financed through about 20% equity share and 80% debt share, the equity interest rate is assumed to be about 7% and the debt interest rate is assumed to be 12%, the aforementioned figures leads to 11% Weighted Average Cost of Capital (WACC). All the existing power plants are assumed to be economically depreciated after 25 years, the owner cost assumed to be 20% of the capital cost.

Techno-economic details of candidate conventional plants

Many technical details have been included to describe the characteristics and the performance of the candidate conventional plants; table 3.10 shows the considered candidate technologies. It is worth mentioning that all the candidate plants to be built until 2017 assumed to have low flexibility, while the candidate plants to be built after 2017 is assumed to have high flexibility, table 3.11 show the flexibility related criteria. All the candidate conventional plants are assumed to have operational lifetime of 35 years. The hourly ambient temperature profile at each hot spots (refer to table 3.8) has been acquisitioned from Meteonorm as it affects the plants' efficiency, it is worth mentioning that the cooling system of all relevant candidate conventional plants (i.e. nuclear plants, coal fired steam plants, and combined cycle plants) located in bus 1, bus 2, and bus 5 were assumed to be through wet cooling tower (located on the river Nile), while plants located in bus 3 and bus 4 were assumed

Table 3.9: Existing conventional plants
Data source: EEHC 2011/2012 annual report [2]

Hot spots of existing conventional plants	Plant's name	Technology	Fuel	First operational year	Last operational year	Number of units	Total gross capacity (MW)
BUS-1-HS-1	CAIRO NORTH	CCGT	Gas	2006	2041	2	1500
BUS-1-HS-1	CAIRO SOUTH	CCGT	Gas	1992	2027	4	615
BUS-3-HS-1	DAMANHOUR	CCGT	Gas	1995	2030	1	157
BUS-4-HS-1	DAMIETTA	CCGT	Gas	1993	2028	3	1200
BUS-2-HS-1	EL-ATF	CCGT	Gas	2010	2045	1	750
BUS-5-HS-1	KUREIMAT	CCGT	Gas	2009	2044	2	1500
BUS-5-HS-1	KUREIMAT ISCC	CCGT	Gas	2011	2046	1	140
BUS-2-HS-2	EL NUBARIA	CCGT	Gas	2007	2042	3	2250
BUS-2-HS-1	MAHMOUDIA	CCGT	Gas	1995	2030	2	316
BUS-3-HS-1	SIDI KRIR	CCGT	Gas	2010	2045	1	750
BUS-2-HS-3	TALKHA (750)	CCGT	Gas	2006	2041	1	750
BUS-2-HS-3	TALKHA (290)	CCGT	Gas	1989	2024	2	290
BUS-3-HS-2	ABU KRIR	GT	Gas	1983	2018	1	24
BUS-4-HS-2	EL SHABAB	GT	Gas	1982	2017	3	101
BUS-3-HS-1	EL SIUF	GT	Gas	1981	2016	6	200
BUS-4-HS-3	HURGHADA	GT	LFO	1991	2026	6	141
BUS-3-HS-1	KARMUS	GT	LFO	1980	2015	2	23
BUS-4-HS-1	PORT SAID	GT	Gas	1984	2019	3	73
BUS-4-HS-3	SHARM EL SHEIKH I	GT	LFO	1979	2014	6	142
BUS-4-HS-3	SHARM EL SHEIKH II	GT	LFO	1997	2032	6	33
BUS-1-HS-2	WADI HOF	GT	Gas	1985	2020	3	100
BUS-1-HS-1	6-OCTOBER	GT	Gas	2012	2047	3	450
BUS-4-HS-2	NEW SHABAB	GT	Gas	2012	2047	8	1000
BUS-4-HS-1	NEW DAMIETTA	GT	Gas	2011	2046	4	500
BUS-1-HS-1	SHOUBRAH EL KHEIMA	GT	Gas	1986	2021	1	35
BUS-3-HS-2	ABU KIR (150)	ST	Gas	1984	2019	6	911
BUS-4-HS-2	ABU SULTAN	ST	Gas	1985	2020	4	600
BUS-4-HS-4	AL-ARISH	ST	Gas	2000	2035	2	66
BUS-5-HS-2	ASSIUT	ST	HFO	1967	2002	3	90
BUS-4-HS-2	ATAKA	ST	Gas	1986	2021	6	900
BUS-4-HS-2	OYOUN MOUSA	ST	Gas	2000	2035	2	640
BUS-1-HS-1	CAIRO WEST I (EXT)	ST	Gas	1995	2030	2	660
BUS-1-HS-1	CAIRO WEST II (EXT)	ST	Gas	2011	2046	2	700
BUS-3-HS-1	DAMANHOUR (OLD)	ST	Gas	1969	2004	3	195
BUS-3-HS-1	DAMANHOUR (EXT)	ST	Gas	1991	2026	1	300
BUS-5-HS-1	EL-KURIEMAT I	ST	Gas	1999	2034	2	1254
BUS-4-HS-2	SUEZ GULF (BOOT)	ST	Gas	2002	2037	2	683
BUS-3-HS-1	KAFR EL DAWAR	ST	Gas	1984	2019	4	440
BUS-3-HS-3	MATROUH	ST	Gas	1990	2025	2	60
BUS-4-HS-1	PORT SAID (BOOT)	ST	Gas	2003	2038	2	683
BUS-1-HS-1	SHOUBRAH EL KHEIMA	ST	Gas	1986	2021	4	1260
BUS-3-HS-1	SIDI KRIR	ST	Gas	2000	2035	2	640
BUS-3-HS-1	SIDI KRIR (BOOT)	ST	Gas	2001	2036	2	683
BUS-2-HS-3	TALKHA	ST	Gas	1994	2029	2	420
BUS-5-HS-1	WALIDIA	ST	HFO	1994	2029	2	624
BUS-1-HS-1	EL-TEBEEN	ST	Gas	2010	2045	2	700

Table 3.10: Candidate conventional plants

Unit type	Unit description	Fuel	Unit gross capacity
AD-NUC	Advanced nuclear power plant	Nuclear	2234
AD-SCPC	Advanced super-critical pulverized coal power plant	Coal	650
AD-CCGT	Advanced combined cycle gas turbine power plant (H-Class)	Gas	400
AD-GT	Advanced gas turbine power plant (F-Class)	Gas	210
DF-IC	Dual-fuel internal combustion engine power plant	HFO	16

to be cooled through sea water cooling (located on the Mediterranean Sea or the Red Sea). Many economic details has been included to describe different associated costs of the candidate conventional plants. It is worth mentioning that all the candidate conventional plants are assumed to have WACC of 8.1% and to be economically depreciated after 25 years, the owner cost assumed to be 20% of the capital cost.

Techno-economic details of existing RE plants

Many technical details have been included to describe the characteristics and the performance of the existing RE plants (i.e. hydropower and wind); table 3.12 shows such existing RE plants. It is worth mentioning that all hydropower plant are located in bus 5 (the reservoir-based plants are very near and could be considered located at the same hot spot, while the run-of-river plants are very near and could be considered located at the same hot spot), while all wind power plants are located in bus 4 within Zafarana wind farm. Many economic details has been included to describe different associated costs of the existing RE plants which assumed to be economically depreciated after 25 years.

Techno-economic details of candidate RE plants

Many technical details have been included to describe the characteristics and the performance of the candidate RE plants. The RE technology-specific hot spots (i.e. CSP, utility-scale PV, and onshore wind power) have been identified according to the methodology explained in section 3.1, the identified hot spots are clearly shown on table 3.3 and figure 3.19. Afterwards normalized hourly generation profile of each RE technology at each respective hot spot has been calculated using

Table 3.11: Flexibility of dispatchable power generation technologies
Data source: [19, 34, 37, 44]

	Minimum load rate		Maximum ramp rate		Minimum online time		Minimum offline time	
	[% rated capacity]		[% /min]		[h]		[h]	
	Min	Max	Min	Max	Min	Max	Min	Max
Candidate plants								
AD-NUC	50	80	1	5	15	24	15	24
AD-SCPC	25	40	3	6	6	8	4	12
AD-CCGT	15	25	4	9	4	4	1	4
AD-GT	20	50	8	8	0	0	0	0
DF-IC	10	30	6	20	0	0	0	0
CSP	20	35	5	10	1	4	1	4
Existing plants								
Hydro-Reservoir	15	15	40	40	0	0	0	0
ST-BIG	20	35	5	10	8	10	5	12
ST-MID	20	35	5	10	8	10	5	12
ST-SMALL	20	35	5	10	8	10	5	12
CCGT-BIG	30	50	4	5	5	10	4	8
CCGT-MID	30	50	4	5	5	10	4	8
CCGT-SMALL	30	50	4	5	5	10	4	8
GT-BIG	20	50	8	8	0	0	0	0
GT-MID	20	50	8	8	0	0	0	0
GT-SMALL	20	50	6	20	0	0	0	0

Table 3.12: Existing RE plants
Data source: NREA 2012/2013 annual report [4]

Plant's name	Technology	Operational year	Total gross capacity (MW)
High Dam	**Hydropower (reservoir)**	1967	2100
Aswan Dam I	**Hydropower (reservoir)**	1960	280
Aswan Dam II	**Hydropower (reservoir)**	1985	270
Esna	**Hydropower (run-of-river)**	1993	86
Naga Hamadi	**Hydropower (run-of-river)**	2008	64
Zafarana-1	**Wind**	2001	63
Zafarana-2	**Wind**	2003	30
Zafarana-3	**Wind**	2004	47
Zafarana-4	**Wind**	2006	85
Zafarana-5	**Wind**	2007	80
Zafarana-6	**Wind**	2008	125
Zafarana-7	**Wind**	2009	92
Zafarana-8	**Wind**	2010	28

the simulation software INSEL [12].

The DNI hourly values in addition to information required to model the performance of the CSP units (e.g. ambient temperature and wind velocity) was acquisitioned from Meteonorm software [14]. Then the normalized hourly generation profiles at the respective hot spots were calculated for the entire year with the modular simulation software INSEL. INSEL has been used to calculate the hourly produced thermal power from a state-of-the-art parabolic trough solar field of 50 MW CSP plant with solar multiple 1 (SM 1). INSEL modules for simulating CSP power generation have been developed by the DLR within the framework of different projects [18, 42]. The calculated heat output generation profiles of a parabolic trough SM 1 solar field were used as input to the REMix-CEM optimization model (see figure 3.26). Figure 3.27 shows the normalized hourly heat output generation profiles of the three identified CSP hot spots.

It is worth mentioning that SM is defined in this context as the ratio between the thermal power generation of the solar field at design con-

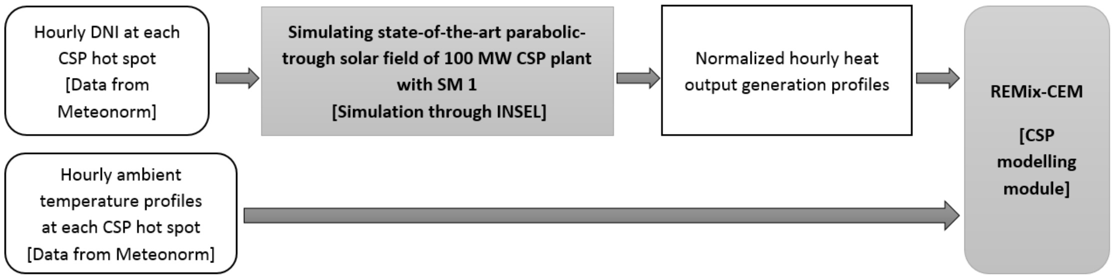

Figure 3.26: Input to the CSP modelling module of the REMix-CEM optimization model

dition and the thermal power which is needed to run the turbine at full load. For example, SM 2 means that the thermal power which is produced by the solar field at design conditions is twice the needed thermal power to run the turbine at full load. The surplus thermal power is used for thermal energy storage that could be used at later time to drive the turbine (e.g. night-time operation).

The REMix-CEM includes a sophisticated CSP module that allows the detailed techno-economic performance modelling of dry- and wet-cooled CSP plants, in addition to optimizing the plant's configuration. Examples of the technical characteristics that are taken into account within the CSP modelling module include time and fuel requirements for start-up, minimum on- and off-line time of the plant, the effects of ambient temperature on dry cooling systems, thermal energy storage characteristics, power block characteristics, required auxiliary power for the solar field, part-load efficiency, and ramping limits of the turbine.

The principle and the data flow of the CSP module within REMix-CEM is shown in figure 3.28. Within the CSP module, the single CSP unit is comprised of four main components, namely solar field (SF), thermal energy storage system (TES), fossil backup boiler system (BUS), and power block (PB) including steam turbine and -dry or wet- cooling system. The performance of each of the four main components and the interaction among them is modelled in detail, in addition to their respective costs. Accordingly, the configuration of each CSP unit can be optimized (in terms of SF size, TES capacity, and BUS capacity) as a step towards optimizing the entire power plant portfolio. Among

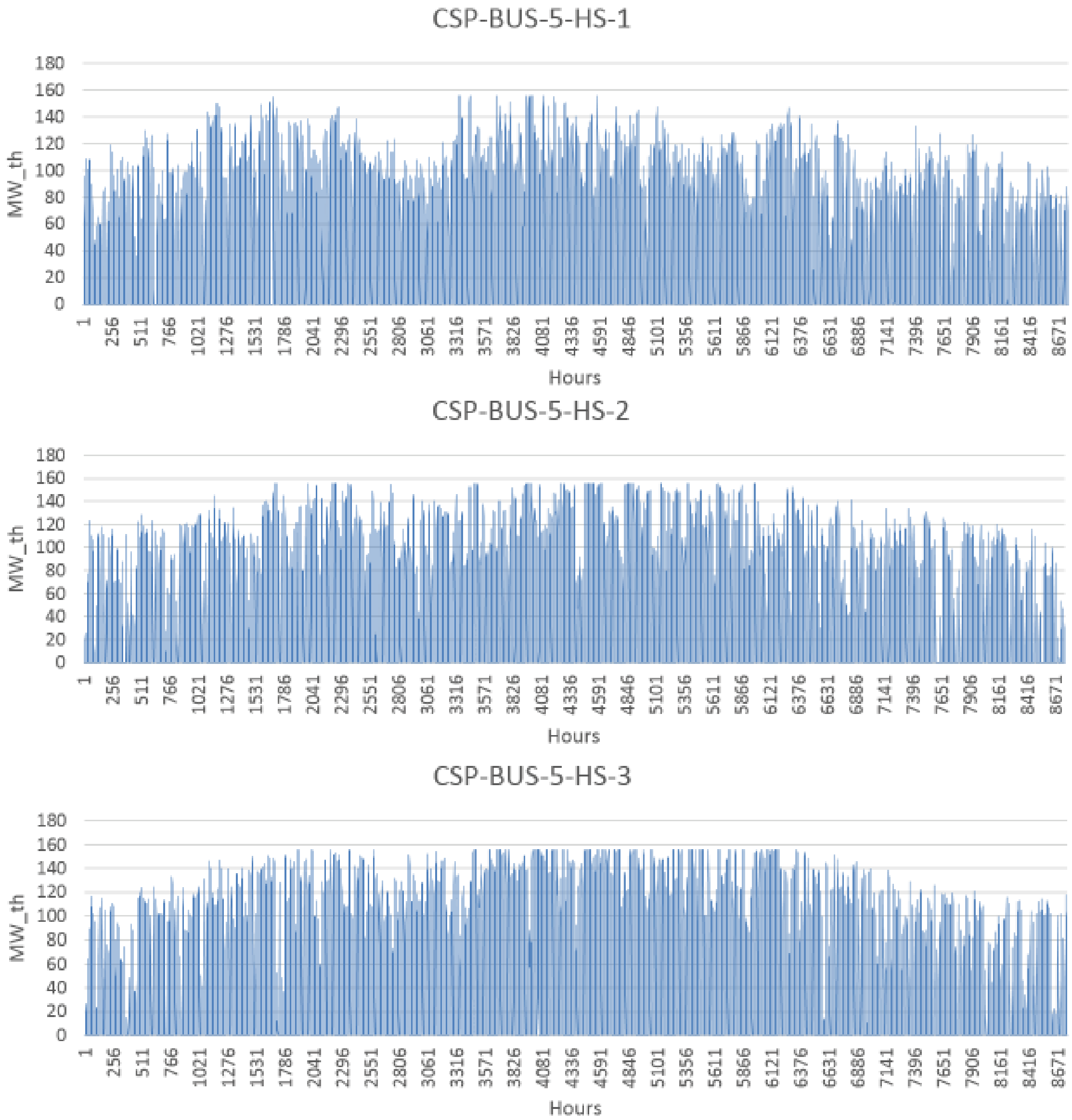

Figure 3.27: CSP hotspots' normalized hourly heat output generation profiles

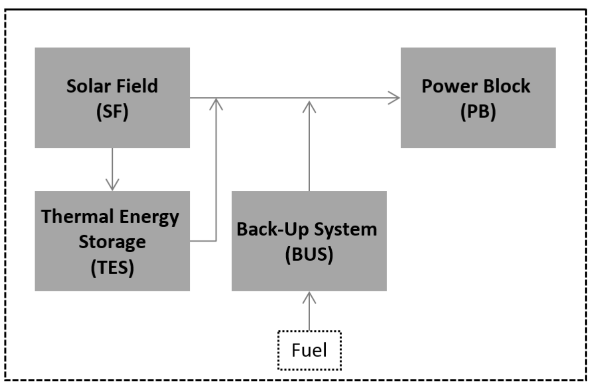

Figure 3.28: CSP modelling module within REMix-CEM

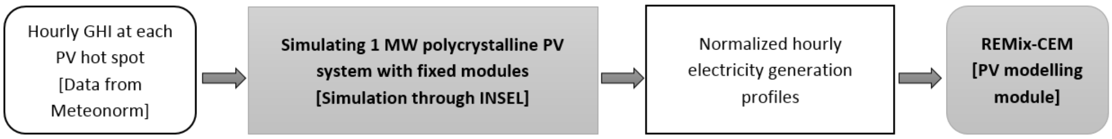

Figure 3.29: Input to the PV modelling module of the REMix-CEM optimization model

the main outcomes of the CSP modelling module are annual capital and operational costs, levelized cost of electricity, hourly dispatch, provided spinning reserve, in addition to optimal plant configuration. Kindly refer to [28] for a more detailed description of the REMIX-CEM impeded CSP modelling module.

The GHI hourly values in addition to information required to model the performance of the PV units was acquisitioned from Meteonorm software [14]. Then the normalized hourly electricity generation profiles at the respective hot spots are calculated with INSEL [12]. INSEL simulated hourly power generation of a 1 MW_p polycrystalline PV system with fixed modules, it is worth mentioning that site-specific hourly meteorological data (e.g. ambient temperature and wind velocity), the optimal inclination of the modules, and all relevant system losses have been taken into consideration. Finally, the calculated normalized hourly electricity generation profiles used as input to the REMix-CEM optimization model (see figure 3.29). Figure 3.30 shows the normalized hourly electricity generation profiles of the three identified PV hot spots.

For the two identified on-shore wind power hot spots hourly wind speed data were taken from Meteonorm and scaled up to match the wind atlas's annual average wind speed. The minimum installable capacity at these hot spots was aligned at Egypt's plan to install about 2 GW of onshore wind power until the year 2020 [4]. Power generation profiles of onshore wind power at the respective hot spots have been modelled using power production curves of a commercially available wind turbine (ENERCON E-70) which has rated capacity of 2.3 MW and hub height of 71 metres. It is worth mentioning that the effects of wind speed inter-hourly variability, turbine inertia, turbulence, wake effects, grid connection losses, and transformer losses have been taken into consideration. Finally, the

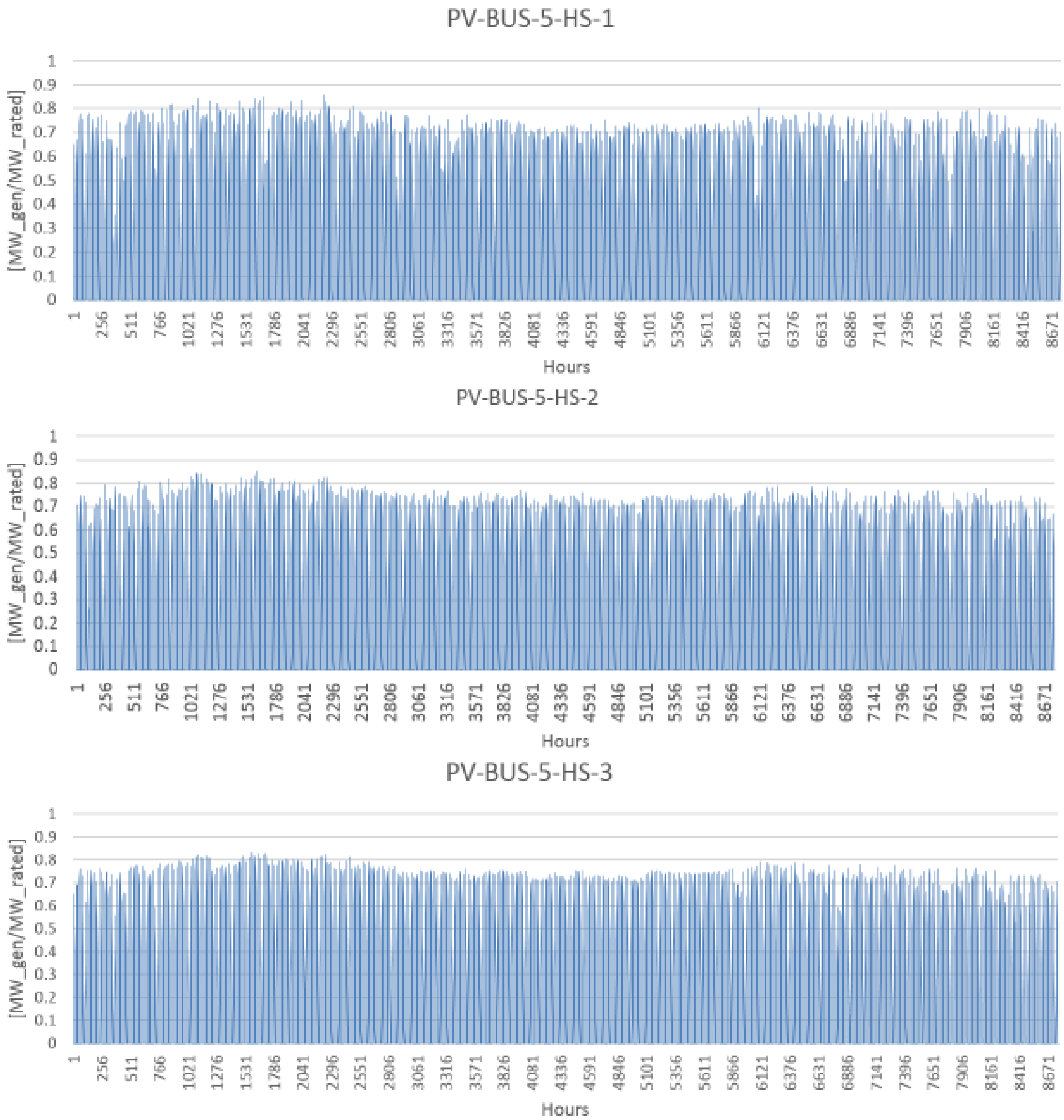

Figure 3.30: PV hotspots' normalized hourly electricity generation profiles

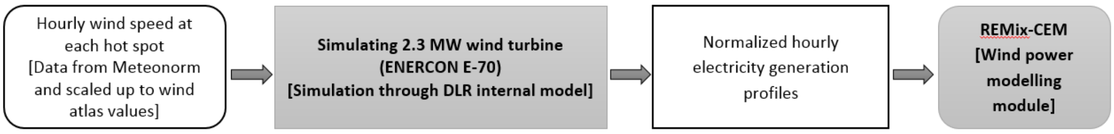

Figure 3.31: Input to the wind power modelling module of the REMix-CEM optimization model

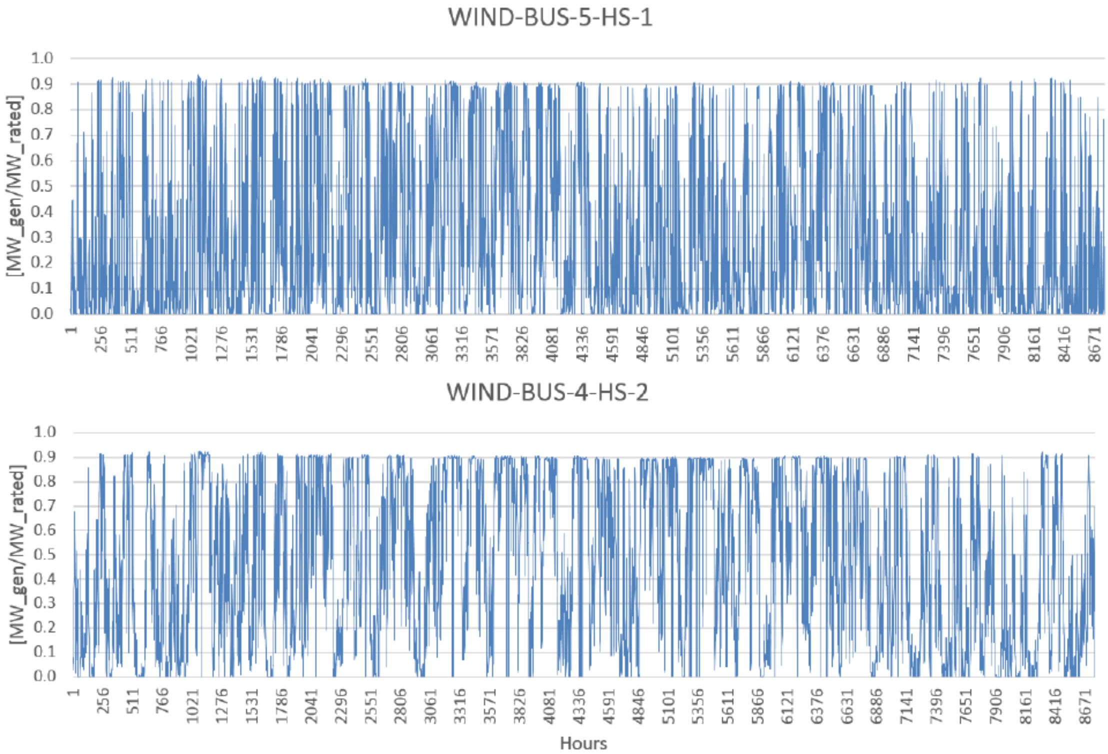

Figure 3.32: Wind power hotspots' normalized hourly electricity generation profiles

calculated normalized hourly electricity generation profiles used as input to the REMix-CEM optimization model (see figure 3.31). Figure 3.32 shows the normalized hourly electricity generation profiles of the two identified wind hot spots.

Many economic details has been included to describe different associated costs of the candidate RE plants, table 3.13 shows the assumed capital cost of each technology at respective year. All the candidate RE plants are assumed to be economically depreciated after 25 years.

Table 3.13: Capital cost of each candidate RE technology
Data source: Trieb, 2011 [38] and Kost, 2013 [31]

Technology	Unit	2017	2022	2027	2032
CSP					
Solar field	EUR/m^2	244	209	187	171
TES	EUR/kWh_{th}	32	28	25	23
BUS	EUR/kW_{th}	82	79	77	76
Power block(*)	EUR/kW	919	886	860	844
Utility-scale PV	EUR/kW	1079	904	782	723
Onshore wind	EUR/kW	1462	1429	1406	1395

* including dry cooling system

3.2.2 Optimization model's description

Traditional optimization techniques of power generation capacity expansion are based on load duration curve approach, which is not the optimum technique to be followed when intermittent and fluctuating RE technologies (e.g. wind power or PV) are included in the capacity planning process. When load duration curve approach is used to handle power system that include RE technologies, usually the power generation of these fluctuating (non-dispatchable) RE technologies is subtracted from the original load profile, resulting in a residual hourly load profile. Then this residual load profile is converted into a residual load duration curve, which is then used to minimize the total costs (e.g. investment, financing, fixed and variable operation and maintenance) of the generation capacity required to cover the residual demand.

The idea of using the load duration curve approach to handle power system that include RE technologies has been challenged because the load chronology and RE resource availability related information is not adequately considered. Additionally, many operational constraints and thermal power generation units' dynamics (e.g. minimum up- and downtimes, minimum generation level, startup costs, ramping limits, part-load efficiency) cannot be taken into consideration while optimizing the power generation capacity expansion through the load duration curve approach. It is worth mentioning that the previously mentioned operational constraints and generation units' dynamics are significantly important especially when RE technologies are part of the capacity expansion optimization. Palmintier and Webster (2012) concluded that neglecting these issues during capacity expansion optimization can lead to suboptimal capacity mixes with significant higher overall generation costs [33].

The used model (REMix-CEM) combines dynamic capacity expansion optimization with unit commitment constraints of thermal power plants, based on real-time hourly load curves. All necessary system and unit constraints are taken into consideration, this enable the model to optimize the integration of RE technologies into the existing power plant portfolio efficiently.

The optimization model developed by the DLR was written using the modelling environment GAMS (General Algebraic Modelling System) and is formulated as mixed integer linear optimization programming (MILP) problem. The optimization problem is solved by the MILP solver CPLEX that apply a simplex algorithm, which determines the optimum by changing variables along the 'outer surface' of the solution space. The values of the parameters are read from input files (e.g. respective databases), then GAMS shall vary the values of the identified variables aiming to reach an optimised solution (i.e. minimisation or maximisation of the objective variable) for the formulated problem.

The model optimizes capacity expansion for a set of candidate conventional and RE generation units taking into account annual capital costs (CAPEX) of the candidate units and annual fixed and variable operation and maintenance costs (OPEX) of all existing and candidate generation units. Therefore, each year of the optimization time-frame is divided into four seasons, each represented by a typical week with an hourly load profile. The hourly load of each week considered in the optimization time-frame has to be covered by the set of existing and candidate units. It is worth mentioning that RE technologies would only be considered as part of the solution, if their integration would contribute to the least cost power supply system. Hence there is no need to subsidize such capacities of technology-specific RE technology as they already lead to the least cost option.

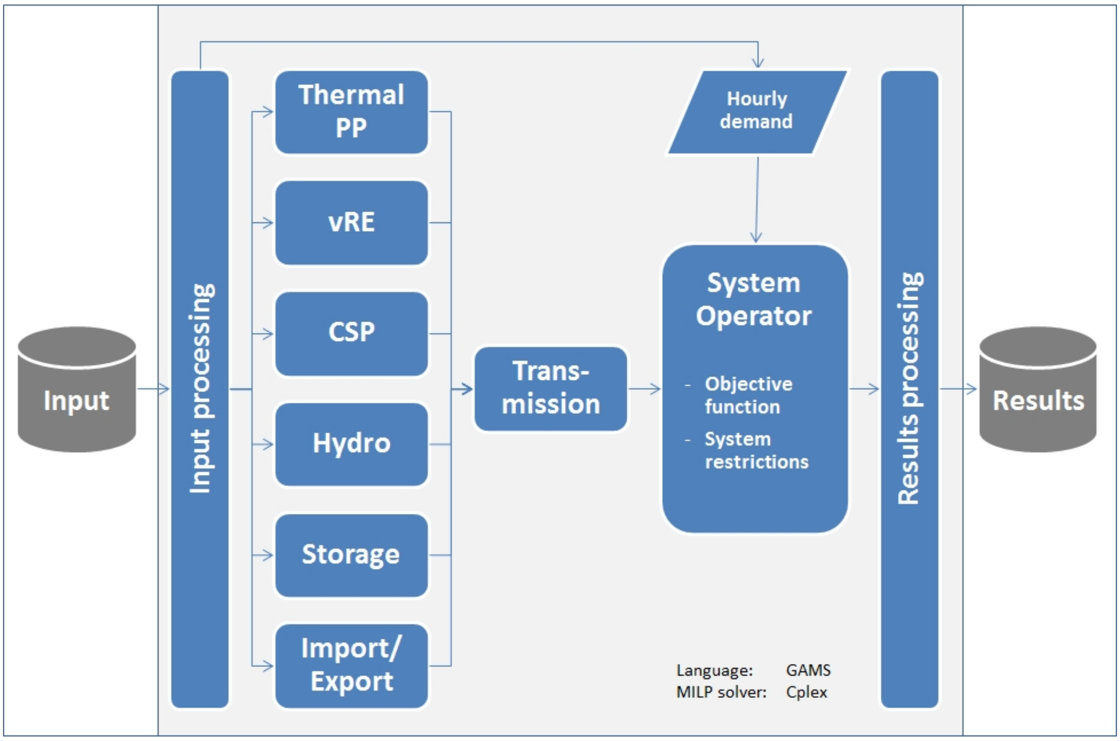

Figure 3.33: REMix-CEM's Modules
Source: Fichter, Expected 2015 [27]

The REMix-CEM optimization model contains several modules that comprehensively describe the techno-economic characteristics and performance of all existing and candidate power generation technologies (both conventional and renewables), besides the overall characteristics and boundary conditions of the power system. Figure 3.33 shows the general structure of REMix-CEM that comprises different modules. It is clear that the model includes dedicated modules that tackles various generation technologies (e.g. conventional fossil technologies, hydro power technologies, CSP etc.). Within the single modules different subtechnologies (e.g. steam turbine, gas turbine, combined cycle gas turbine etc.) are modelled on single unit scale. There are many restrictions applied on the unit level to model various conventional and RE power generation units.

There are a lot of considered constraints both on power system scale (e.g. spinning reserve requirements, grid transfer capacities etc.) and generation unit scale (e.g. minimum load level, start-up times etc.) to ensure the minimization of the total system costs without compromising the security of supply at any given moment. In total there are more than 130 embedded equations within REMix-CEM, explaining the full details of the REMix-CEM optimization model goes beyond the scope of this master thesis, for more details about the REMix-CEM optimization model refer to [27].

4 Results and Discussion

This chapter elaborates on the different investigated scenarios and their considered assumptions. The detailed results of the two most important scenarios would be discussed thoroughly, besides a reflection upon all the five investigated scenarios.

The capacity expansion optimization for Egypt's power system has been conducted for a 20-year time frame starting from the status of the year 2012 (the last year with accurate data provided by the utility). The capacity expansion has been optimized dynamically, taking into account the planning milestones 2017, 2022, 2027, and 2032. Each milestone year has been divided into four seasons where in turn one representative week for each season has been considered for optimization.

4.1 Scenarios and Assumptions

Five scenarios have been modelled to investigate the impacts of the uncertainty related to the future fuel price-escalation and future resource availability. Two fuel price-escalation scenarios has been considered (i.e. Mid scenario with annual increase of 2% (real) and High with annual increase of 3.5% (real)), table 4.1 shows the estimated fuel prices according to the different fuel price-escalation scenarios. Two RE generation scenarios has been considered (i.e. Mid and High), table 4.2 shows the week in each season that represent different RE generation scenarios that has been identified based on the collective RE resources availability in all the identified RE hot spots (i.e. three CSP hot spots, three PV hot spots, and two wind hot spots). It is worth mentioning that the ninth

Table 4.1: Estimated fuel prices according to the different fuel price-escalation scenarios

Fuel price in [EUR/MWh$_{th}$]		2017	2022	2027	2032
LFO	Mid	56.5	62.4	68.9	76.0
	High	58.2	69.1	82.0	97.4
HFO	Mid	45.8	50.5	55.8	61.6
	High	47.1	56.0	66.5	79.0
Gas	Mid	28.1	31.0	34.3	37.8
	High	28.9	34.4	40.8	48.5
Coal	Mid	14.5	16.1	17.7	19.6
	High	15.0	17.8	21.1	25.1
Nuclear	Mid	7.7	8.5	9.4	10.4
	High	7.9	9.4	11.2	13.3

Table 4.2: The week in each season that represent different RE generation scenarios

Season	Collective RE resource availability for all identified RE hot spots	
	Mid	High
Winter	Week 7	Week 8
Spring	Week 8	Week 11
Summer	Week 12	Week 7
Autumn	Week 5	Week 4

week in the summer (i.e. season 3) represents the week with the highest peak load, accordingly the load dispatch for all the four seasons has been simulated during the ninth week of the season assuming that different RE generation scenarios could happen during this weeks. Only one week per season was considered for optimization due to the high computation effort resulting from the very large problem size.

The high initial capital costs of the CSP technology is still the most significant factor for CSP adoption. Hence for CSP projects in Egypt to be economically feasible and consequently included amongst the least cost capacity expansion plans in the short to medium term, the reduction of the capital costs would be necessary in addition to participating in the carbon emissions trading and offering policy incentives (e.g. long-term power purchase agreements, feed-in tariffs or tax incentives).

A comprehensive study to assess the local manufacturing potential for CSP projects in MENA region was commissioned by the World Bank

Table 4.3: Different modelling scenarios and their respective assumptions and purpose

Modelling scenario	Fuel price-escalation assumption	RE generation assumption	Purpose
Scenario 1	Mid	Mid	- the base scenario
Scenario 2		Mid [CSP capital cost reduced by 20%]	- investigating the impact of CSP capital cost reduction on the results
Scenario 3		High	- investigating the impact of high RE generation on the results
Scenario 4	High	Mid	- investigating the impact of high fuel price-escalation on the results
Scenario 5		High	

with donor support from the Energy Sector Management Assistance Program (ESMAP), the study was carried out in 2010 by Ernst and Young (France) and Fraunhofer Institute (Germany). The study stated that MENA has technical and industrial capabilities which are likely to form a good basis on which to build CSP-related activities. The study analysed all relevant industries that could participate in local manufacturing of CSP plant's components, and concluded that if the CSP market grows continuously in MENA, there would be an increasing potential for local manufacturing of components for CSP [30]. Also the construction work and engineering services for new CSP plants in the MENA region has been indicated as activities with promising prospects to be carried out by local firms in the future. According to the study, figure 4.1 shows the breakdown of the capital costs of a standard CSP plant (i.e. total investment of a typical CSP plant of 50 MW) and the estimations of the attainable local manufacturing shares.

The ESMAP study concluded that activities corresponding to 60% of CSP plants' capital cost be achieved locally within MENA region within the coming decade. Given the Egyptian context at the present time, plant construction and civil works in addition to steel structures and non-CSP-specific components could be handled locally. Egypt is home of one the biggest glass processor in MENA region (Dr. Greiche) which could be interested in CSP mirror production in the future.

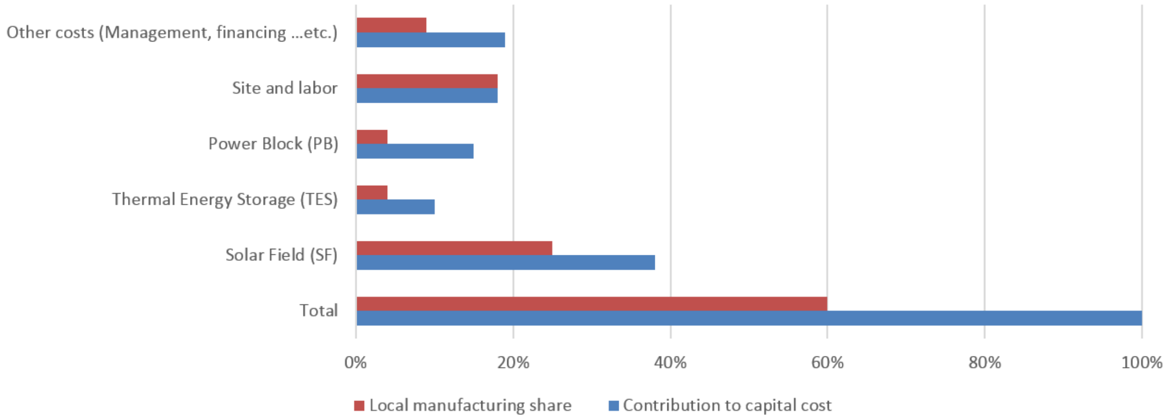

Figure 4.1: Local manufacturing shares by component
Data source: The World Bank [30]

In the light of the above mentioned argument about the potential reduction of CSP capital cost in contrast to the international estimated future capital cost, Scenario 2 investigated the effect of CSP capital cost reduction by 20% on the results (refer to table 4.3).

4.2 Results' Discussion of Different Scenarios

Only Scenario 1 and Scenario 2 have been modelled twice: once taking into account the unit commitment constrains of the dispatchable thermal generators and once without taking their unit commitment constrains into consideration. The rest scenarios have been only modelled once without unit commitment constrains due to the long required computation time resulting from the very large problem size when applying unit commitment constrains that may take up to 30 hours for one model run. The unit commitment constrains include:

- Start-up performance of dispatchable power generation technologies (e.g. start-up time, fuel consumption at start-up, additional start-up cost, cycling cost ...etc.)
- Flexibility of dispatchable power generation technologies (for detailed flexibility related criteria, refer to table 3.11)
- Part-load performance of power generation technologies

2017	2022	2027	2032
AD-CCGT-1 [8000 MW] Bus 1	AD-CCGT-6 [3200 MW] Bus 1	AD-CCGT-11 [6000 MW] Bus 1	AD-CCGT-16 [6800 MW] Bus 1
AD-CCGT-2 [1600 MW] Bus 2	AD-CCGT-7 [800 MW] Bus 2	AD-CCGT-12 [800 MW] Bus 2	AD-CCGT-17 [2000 MW] Bus 2
AD-CCGT-3 [4000 MW] Bus 3	AD-CCGT-8 [800 MW] Bus 3	AD-CCGT-13 [1600 MW] Bus 3	AD-CCGT-18 [1200 MW] Bus 3
AD-CCGT-4 [400 MW] Bus 4	AD-CCGT-10 [800 MW] Bus 5	AD-GT-11 [1260 MW] Bus 1	AD-GT-16 [1680 MW] Bus 1
AD-CCGT-5 [4000 MW] Bus 5	AD-GT-6 [2100 MW] Bus 1	AD-GT-13 [840 MW] Bus 3	AD-GT-17 [630 MW] Bus 2
AD-GT-4 [420 MW] Bus 4	AD-GT-7 [1470 MW] Bus 2	AD-GT-14 [420 MW] Bus 4	AD-GT-18 [420 MW] Bus 3
WIND-2 [3889 MW] Ras Ghareb	AD-GT-8 [1890 MW] Bus 3	WIND-8 [963 MW] Ras Ghareb	AD-GT-19 [1470 MW] Bus 4
	AD-GT-9 [2100 MW] Bus 4	PV-9 [896 MW] N. El-Shaikh	AD-GT-20 [210 MW] Bus 5
	AD-GT-10 [1890 MW] Bus 5		WIND-11 [1415 MW] Ras Ghareb
	WIND-5 [4768 MW] Ras Ghareb		WIND-12 [187 MW] west Nile
	WIND-6 [915 MW] west Nile		PV-11 [1500 MW] N. El-Hamam
	PV-4 [200 MW] Kom-Ombo		PV-12 [10000 MW] N. El-Shaikh
	PV-6 [70 MW] N. El-Shaikh		

Figure 4.2: Capacity expansion plan according to Scenario 1 with unit commitment constraints

Refer to [27] for detailed description of the unit commitment constraints and the exact values assigned to different parameters respective to each generation technology (conventional or renewables). Figure 4.2 shows the capacity expansion plan according to Scenario 1 with unit commitment constraints.

4.2.1 A look at Scenario 1 with and without unit commitment constrains

Figure 4.3 shows the capacity expansion according to Scenario 1 (i.e. Mid fuel price escalation assumption and Mid RE generation assumption) with and without unit commitment, while figure 4.4 shows the fuel share of total generated electricity. The major difference when Scenario 1 was modelled with and without unit commitment constraints is that the wind installed capacity in 2017 increased from 0.5 GW when the model was

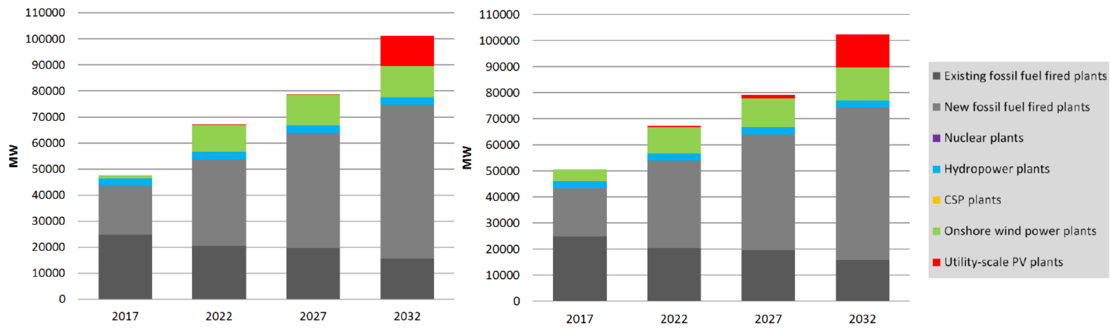

Figure 4.3: Capacity expansion (Sc1)
without unit commitment (left) and with unit commitment (right)

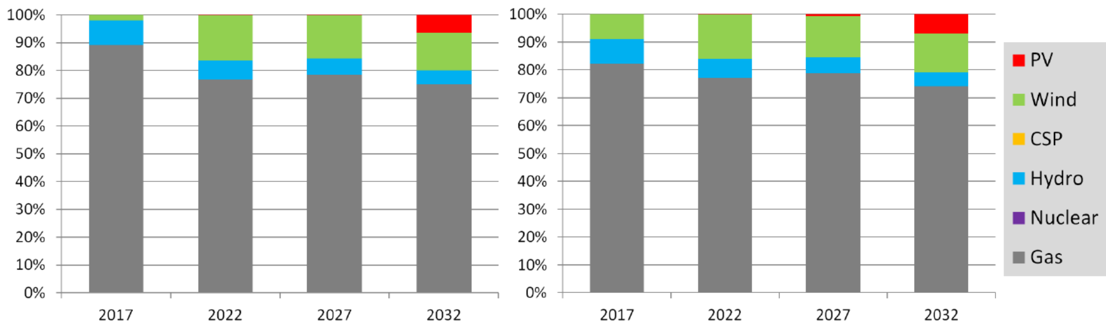

Figure 4.4: Fuel share of total generated electricity (Sc1)
without unit commitment (left) and with unit commitment (right)

run without unit commitment constraints to 3.9 GW when the model was run with unit commitment constraints. Consequently in 2017 the generation share of wind increased from 2% without unit commitment constraints to 9% with unit commitment constraints, reducing the gas fuel generation share from 89% to 82%.

Figure 4.5 shows the average system cost according to Scenario 1. It is clear also that the average system cost that increased from 7.5 ct/kWh in 2017 to 8.7 ct/kWh in 2032 when Scenario 1 was modelled without unit commitment constraints, while it has been increased from 7.5 ct/kWh in 2017 to 8.8 ct/kWh in 2032 when Scenario 1 was modelled with unit commitment constraints. Generally, the average system cost with unit commitment constraints is 1 ct/kWh higher than the average system cost without unit commitment constraints.

Figure 4.6 shows the development of the unit dispatch for the planning steps 2017, 2022, 2027 and 2032 (Scenario 1) exemplary for the week of

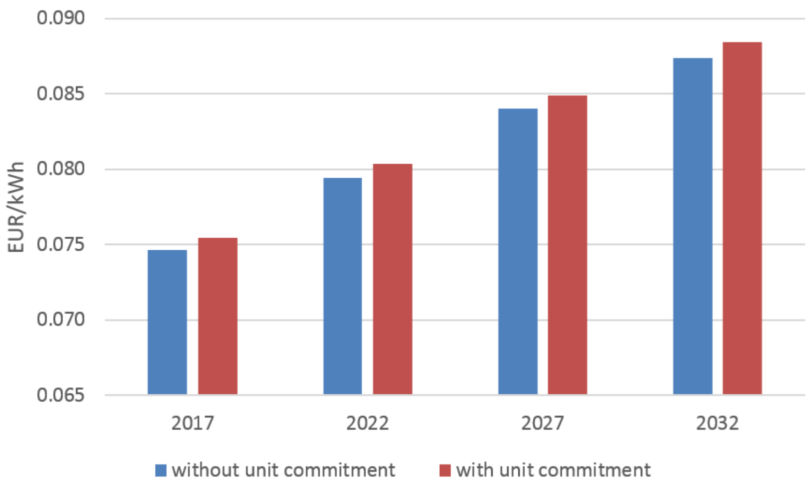

Figure 4.5: Average specific generation cost (Sc1)
without unit commitment (left) and with unit commitment (right)

the highest demand (the 9th summer week). The midday-peak and the evening-peak which are served mainly by ST plants (fired by expensive gas) in 2017 would be replaced mainly by wind plants until 2027, and by 2032 PV plants would contribute significantly during the midday-peak. It is also very clear that wind power contributes significantly to the generating mix through the day, so wind power is used as a cheap fossil fuel saver due to its low generation costs (especially at the well-selected hot spots).

Figure 4.7 shows the Full Load Hours (FLH) of all newly installed plants from 2017 through 2032, while figure 4.8 shows their Levelized Cost of Electricity (LCOE). As CCGT usually cover the base load, many CCGT plants have up to 8760 FLH and their LCOE ranges between 6 and 10 ct/kWh. The GT plants are operated only for very short time during the evening peak, so they have less than 90 FLH (without unit commitment constrains) and less than 600 FLH (with unit commitment constrains). Consequently their LCOE reaches up to 144 EUR/kWh (without unit commitment constrains) and up to 28 EUR/kwh (with unit commitment constrains). The PV plants have around 2000 FLH, while the wind parks have between ca. 3000 and ca. 4000 FLH. The LCOE of both PV and wind plants ranges between 6 and 8 ct/kWh.

It is worth mentioning that when Scenario 1 with modelled with unit

Table 4.4: Technical details of the introduced CSP plants

Scenario 2	CSP plant's location	Installed units	Installed Capacity [GW]	Solar Multiple (SM)	Thermal Energy Storage (TES) [hours]	Back-up System (BUS) [% of turbine capacity]
without unit commitment	east Qena	70	7.0	2.35	7.7	100
	west Asiut	36	3.6	2.13	8.2	100
with unit commitment	east Qena	58	5.8	2.31	7.7	93
	west Asiut	42	4.2	2.00	7.9	100

commitment constrains, the LCOE generated from CCGT increases from 7 ct/kWh in 2017 to 9 ct/kWh in 2032 (this is influenced by the expected escalation of the fossil fuel price) while the LCOE generated from renewables (wind and PV) is stabilized around 7 ct/kWh from 2017 through 2032.

4.2.2 A Look at Scenario 2 with and without unit commitment constrains

Figure 4.9 shows the capacity expansion according to Scenario 2 (i.e. Mid fuel price escalation assumption and Mid RE generation assumption, considering 20% reduction of CSP capital cost) with and without unit commitment, while figure 4.10 shows the fuel share of total generated electricity. The major difference when Scenario 2 was modelled with and without unit commitment constraints is that the wind installed capacity in 2017 increased from 3.1 GW when the model was run without unit commitment constraints to 5.2 GW when the model was run with unit commitment constraints. Consequently in 2017 the generation share of wind increased from 7% without unit commitment constraints to 12% with unit commitment constraints, reducing the gas fuel generation share from 84% to 79%.

Table 4.4 shows some technical details of the introduced CSP plants when Scenario 2 was modelled with and without unit commitment constraints. It is worth mentioning that all the CSP plants was only introduced in 2032.

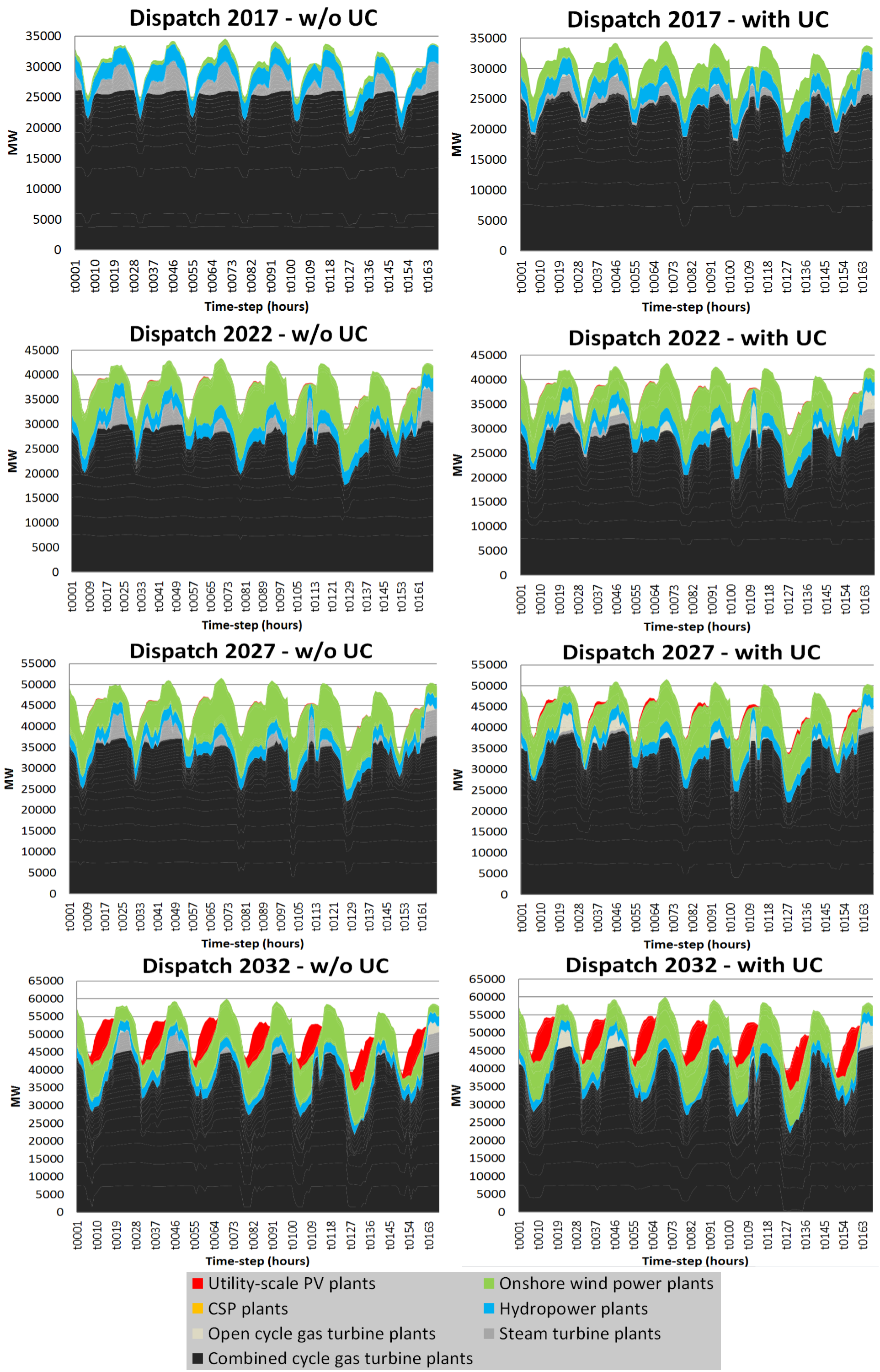

Figure 4.6: Highest demand week extract from the annual hourly power dispatch of the entire system (Sc1)
without unit commitment (left) and with unit commitment (right)

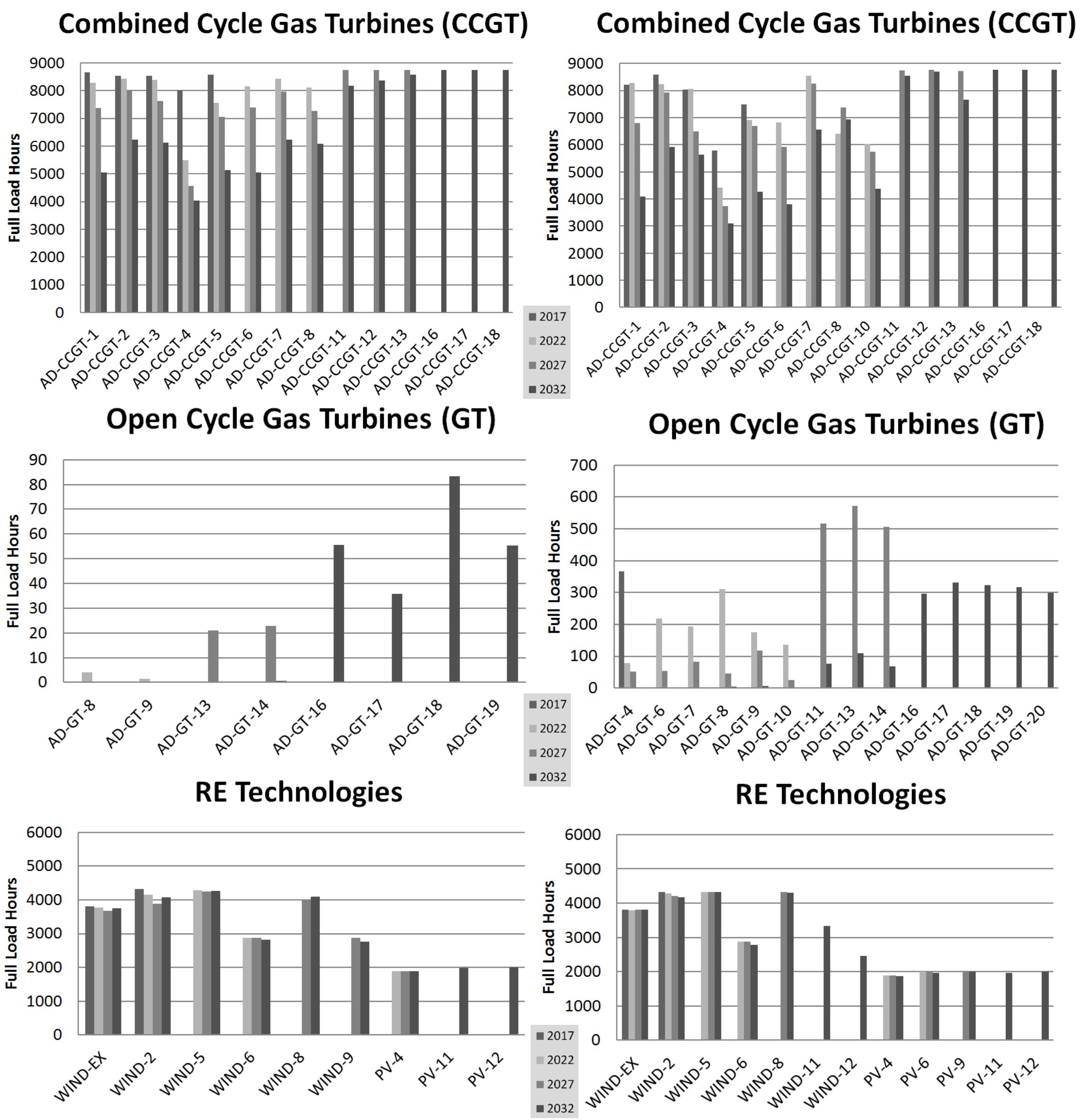

Figure 4.7: Full load hours (FLH) of all newly installed plants from 2017 through 2032 (Sc1) without unit commitment (left) and with unit commitment (right)

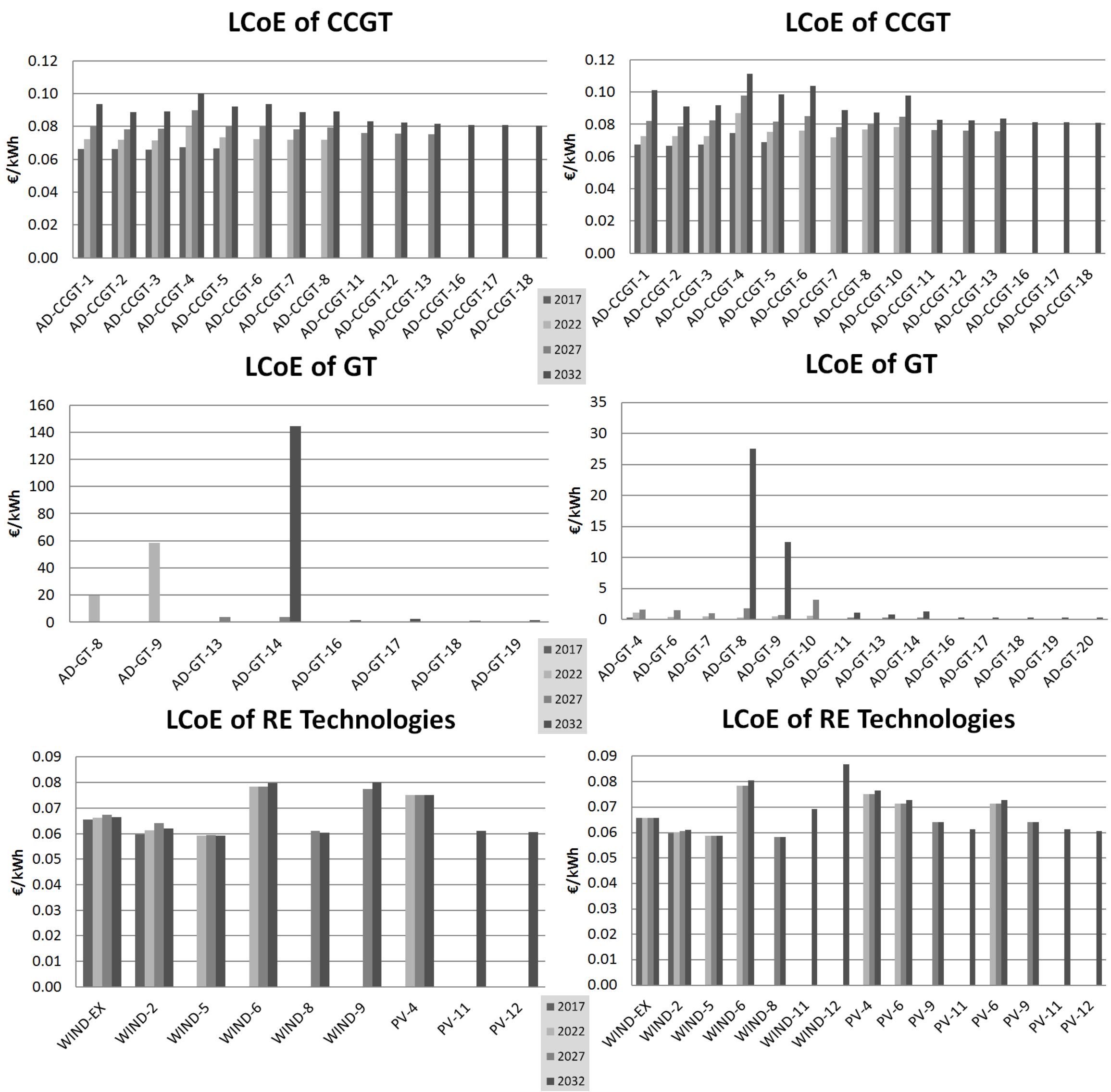

Figure 4.8: Levelized cost of electricity (LCOE) of all newly installed plants from 2017 through 2032 (Sc1)
without unit commitment (left) and with unit commitment (right)

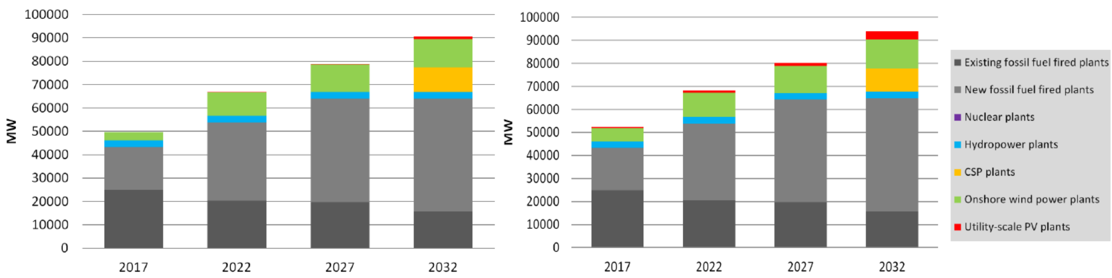

Figure 4.9: Capacity expansion (Sc2)
without unit commitment (left) and with unit commitment (right)

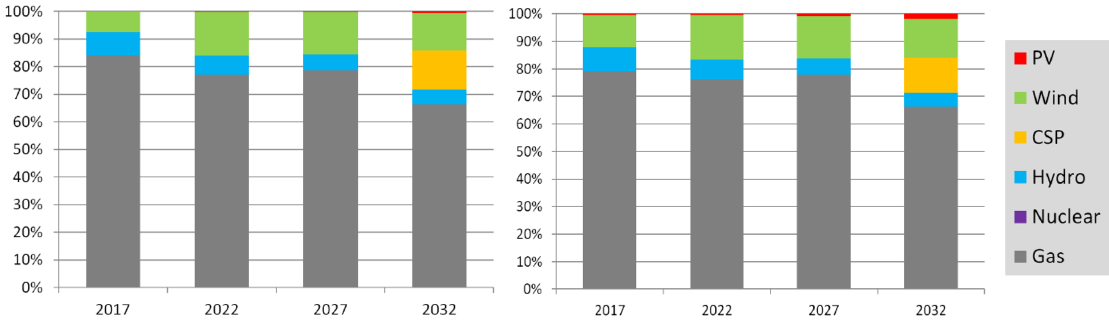

Figure 4.10: Fuel share of total generated electricity (Sc2)
without unit commitment (left) and with unit commitment (right)

Figure 4.11 shows the average system cost according to Scenario 2. It is clear also that the average system cost that increased from 7.5 ct/kWh in 2017 to 8.7 ct/kWh in 2032 when Scenario 2 was modelled without unit commitment constraints, while it has been increased from 7.6 ct/kWh in 2017 to 8.8 ct/kWh in 2032 when Scenario 2 was modelled with unit commitment constraints. Generally, the average system cost with unit commitment constraints is 1 ct/kWh higher than the average system cost without unit commitment constraints.

Figure 4.12 shows the development of the unit dispatch for the planning steps 2017, 2022, 2027 and 2032 (Scenario 2) exemplary for the week of the highest demand (the 9^{th} summer week). The midday-peak and the evening-peak which are served mainly by ST and GT plants (fired by expensive gas) in 2017 would be replaced mainly by wind plants until 2027, and by 2032 CSP plants would contribute significantly during both midday-peak and evening peak in addition to a small contribution from PV during midday-peak. It is worth mentioning that the CSP units are highly dispatchable as they are equipped with TES and BUS (refer

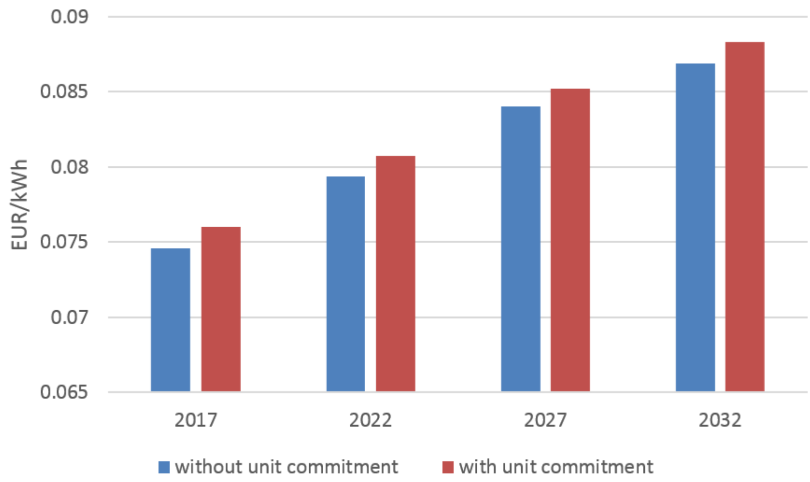

Figure 4.11: Average specific generation cost (Sc2)
without unit commitment (left) and with unit commitment (right)

to Table 4.4), so during morning hours the surplus thermal energy is stored in the storage system to be used during the evening hours when the power demand increases to reach its peak, making CSP (if their capital cost could be reduced by about 20%) a valuable option for Egypt's power supply system as it offers both firm and flexible power generation capacity. It is also very clear that wind power contributes significantly to the generating mix through the day, so wind power is used as a cheap fossil fuel saver due to its low generation costs (especially at the well-selected hot spots).

Figure 4.13 shows the full load hours (FLH) of all newly installed plants from 2017 through 2032, while figure 4.14 shows their levelized cost of electricity (LCOE). As CCGT usually cover the base load, many CCGT plants have up to 8760 FLH and their LCOE ranges between 6 and 10 ct/kWh. The GT plants are operated only for very short time during the evening peak, so they have less than 50 FLH (without unit commitment constrains) and well less than 615 FLH (with unit commitment constrains). Consequently their LCOT reaches up to 20 EUR/kWh (without unit commitment constrains) and up to 33 EUR/kwh (with unit commitment constrains). The PV plants have around 2000 FLH, while the wind parks have between ca. 3000 and ca. 4000 FLH. The LCOE of both PV and wind plants ranges between 6 and 8 ct/kWh. In 2032 CSP plants contribute as mid merit power plants with about 5000 FLH that increases significantly the share of RE on the overall power generation, the LCOE of the CSP plants is about 8 ct/kWh.

It is worth mentioning that when Scenario 2 with modelled with unit commitment constrains, the LCOE generated from CCGT increases from 7 ct/kWh in 2017 to 9 ct/kWh in 2032 (this is influenced by the expected escalation of the fossil fuel price), while the LCOE generated from renewables (wind, PV, and CSP) is stabilized around 7 ct/kWh from 2017 through 2032.

4.2.3 A Look at five scenarios without unit commitment constrains

This section elaborates on the results of the five scenarios (modelled without taking the unit commitment constrains of the dispatchable thermal generators). Figure 4.15 shows the capacity expansion according to each scenario, figure 4.16 shows the share of RE installed capacity, and figure 4.17 shows the fuel share of the total generated electricity.

Comparing Scenario 2 with Scenario 1

Both scenarios assumed Mid fuel price-escalation and Mid RE generation. Scenario 2 investigates the impact of CSP capital cost reduction (by 20%) on the results. It is noticeable that more wind power is introduced in 2017; ca. 3 GW new installed capacity in Scenario 2 compared with only ca. 0.5 GW in Scenario 1, and generation share is 7.4% in Scenario 2 compared with only 2% in Scenario 1. In Scenario 2 more than 10 GW of CSP is introduced in 2032 (represents generation share of 14%), reducing the PV new installed capacity in 2032 from more than 11 GW in Scenario 1 to less than 1 GW in Scenario 2. It is worth mentioning that introducing CSP in 2032 (that contributes to the firm capacity as it includes back-up system) reduced the total installed capacity in 2032 from ca. 100 GW in Scenario 1 to ca. 90 GW in Scenario 2.

Scenario 2 confirmed that reducing the CSP capital cost would be the

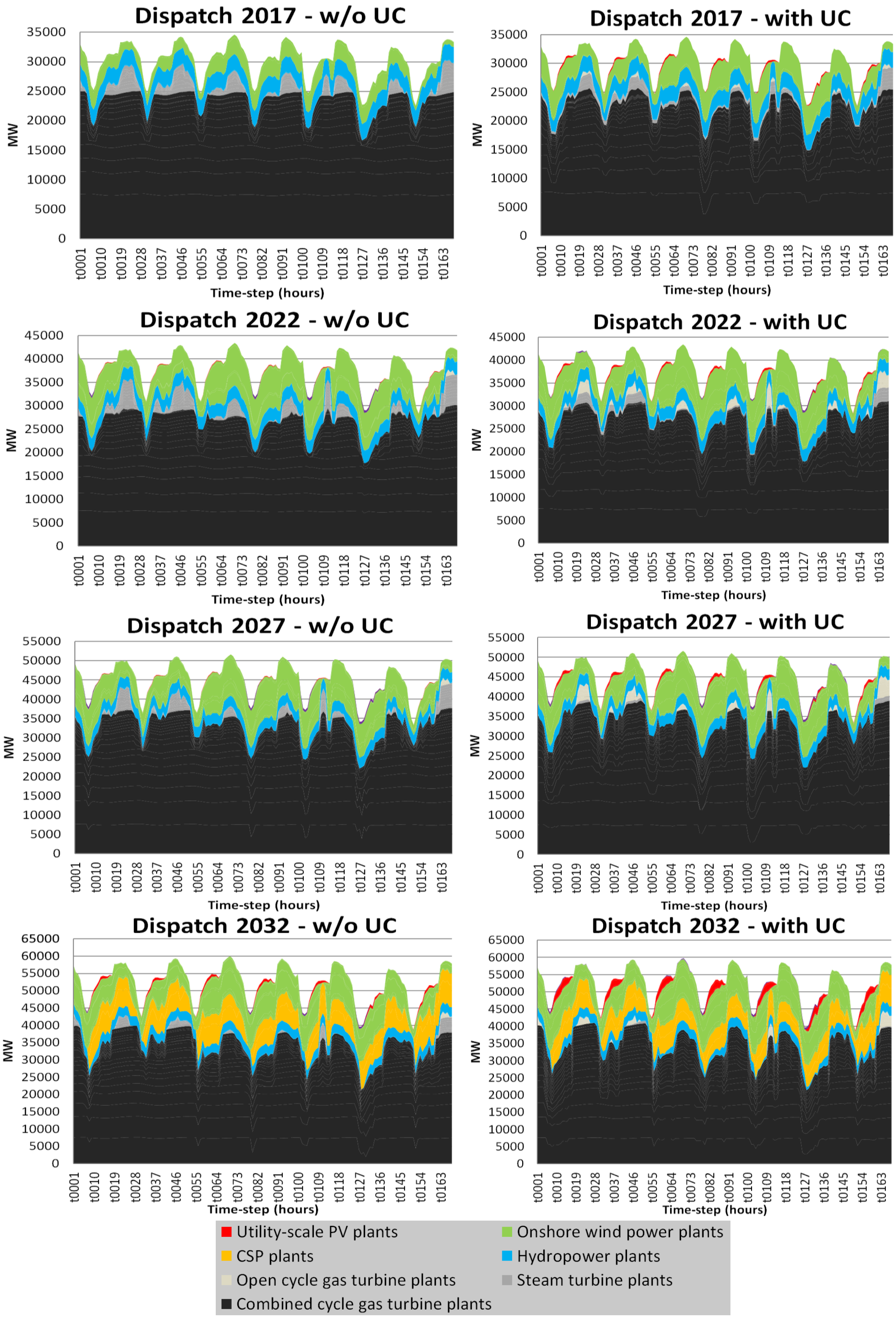

Figure 4.12: Highest demand week extract from the annual hourly power dispatch of the entire system (Sc2)
without unit commitment (left) and with unit commitment (right)

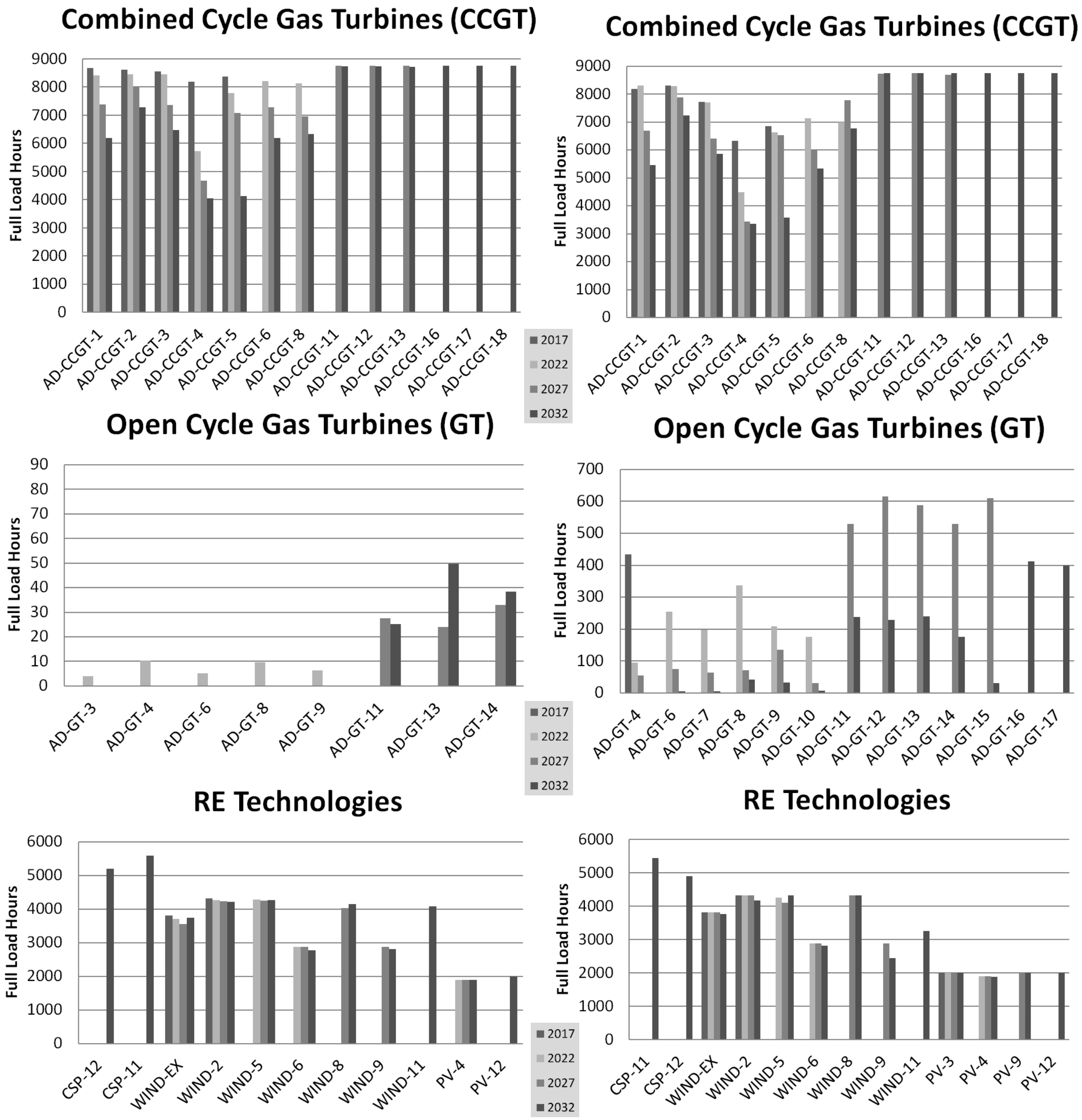

Figure 4.13: Full load hours (FLH) of all newly installed plants from 2017 through 2032 (Sc2) without unit commitment (left) and with unit commitment (right)

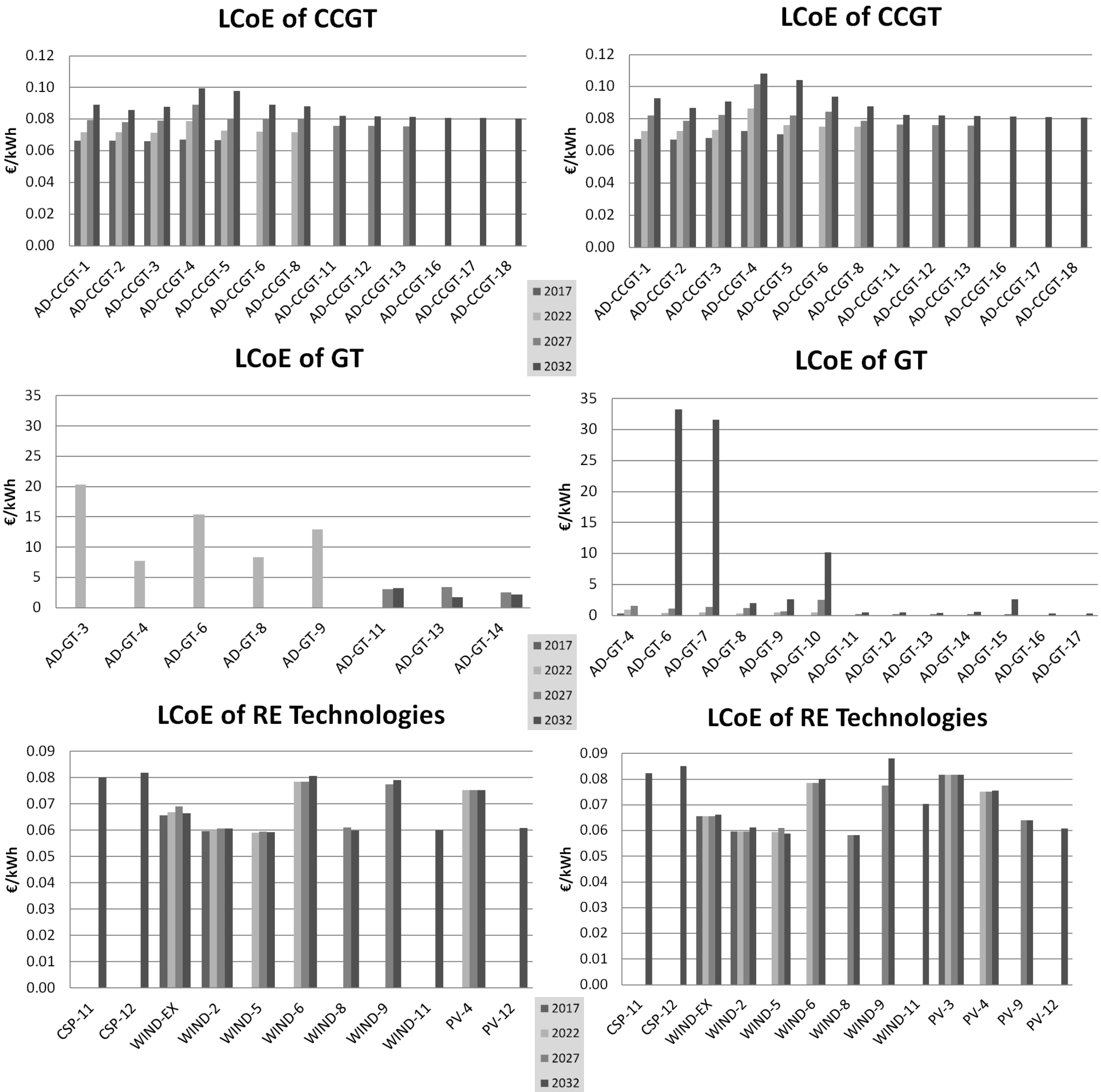

Figure 4.14: Levelized cost of electricity (LCOE) of all newly installed plants from 2017 through 2032 (Sc2)
without unit commitment (left) and with unit commitment (right)

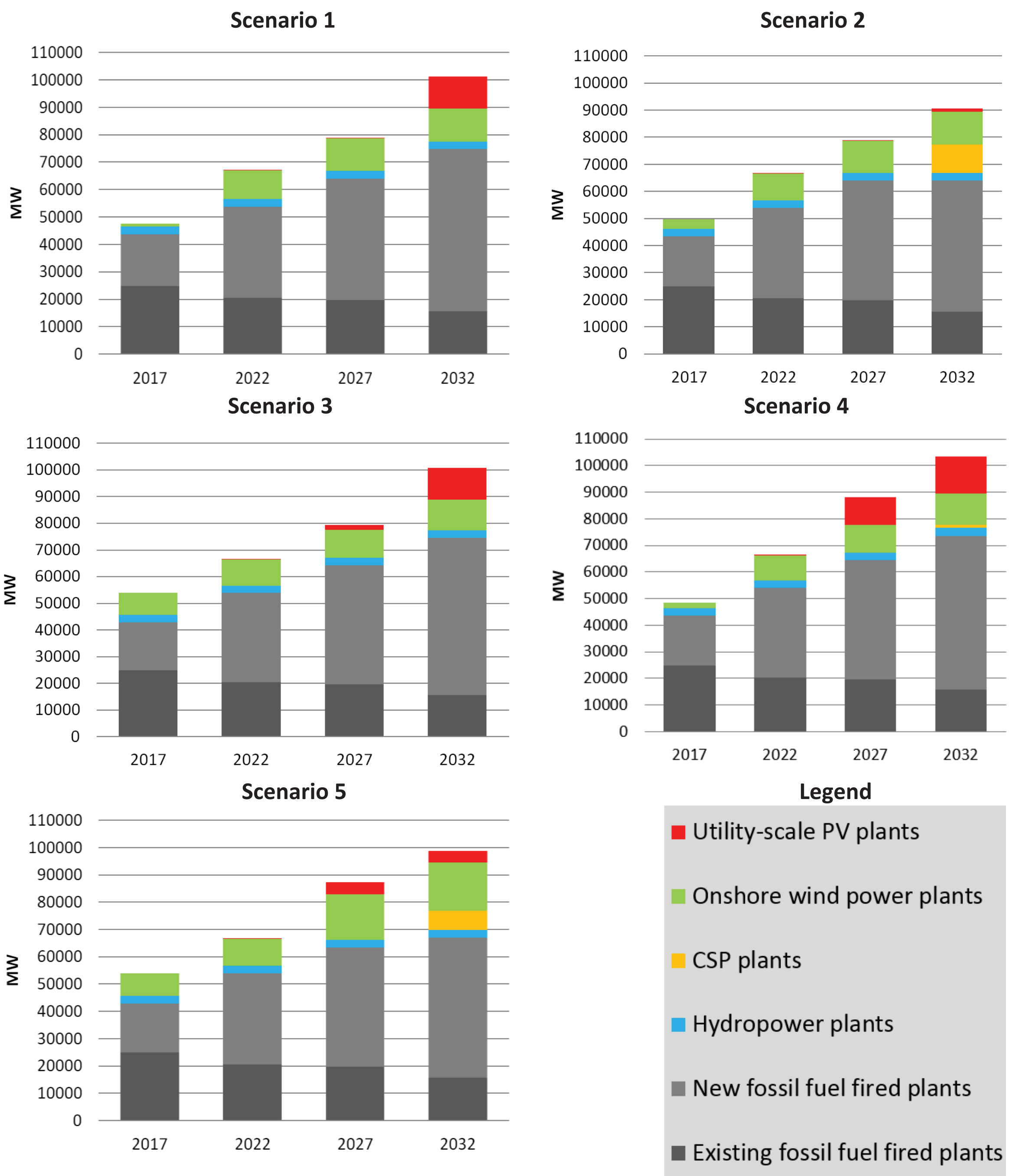

Figure 4.15: Capacity expansion without unit commitment constraints

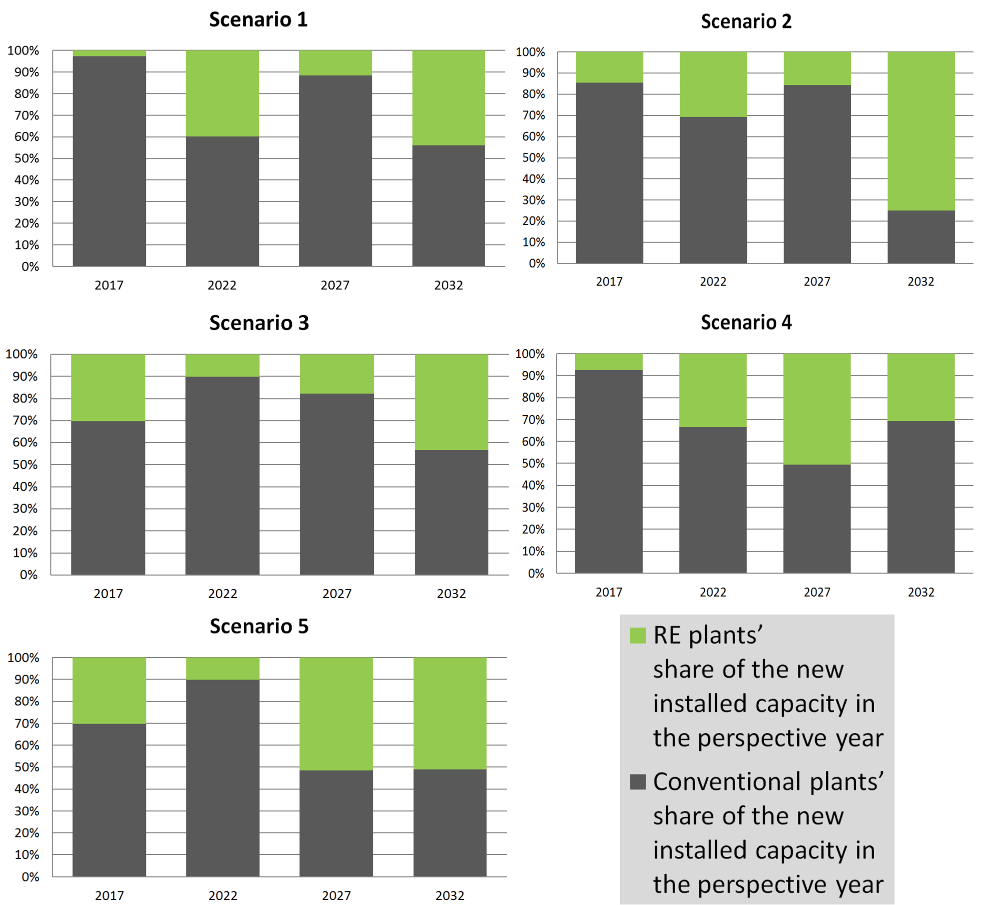

Figure 4.16: RE technologies share of installed capacity without unit commitment constraints

Figure 4.17: Fuel share of total generated electricity without unit commitment constraints

major factor to make CSP as an economically feasible option (given that no restriction on the available amount of natural gas as long as it could be imported with forecast international market price). CSP capital cost is expected to be reduced in Egypt and MENA region as discussed in section 4.1.

Comparing Scenario 3 with Scenario 1

Both scenarios assumed Mid fuel price-escalation. But while Scenario 1 assumed Mid RE generation, Scenario 2 assumed High RE generation. Scenario 3 investigates the impact of High RE generation on the results. It is noticeable that more wind power is introduced in 2017; ca. 8 GW new installed capacity in Scenario 3 compared with only ca. 0.5 GW in Scenario 1, and generation share is 22% in Scenario 3 compared with only 2% in Scenario 1, consequently the gas fuel generation share reduced from ca. 90% in Scenario 1 to only 70% in Scenario 3. Additionally in Scenario 3 ca. 1.7 GW of PV is introduced in 2027.

Comparing Scenario 4 with Scenario 1

Both scenarios assumed Mid RE generation. But while Scenario 1 assumed Mid fuel price-escalation, Scenario 4 assumed High fuel price-escalation. Scenario 4 investigates the impact of High fuel price-escalation on the results. In Scenario 4 more than 10 GW of PV is introduced in 2027, consequently the PV generation share is increased in 2027 from almost nothing in Scenario 1 to 6.6% in Scenario 4. It is also noticeable that 1.1 GW of CSP is introduced in 2032 that contributes to 1.2% of the generation share at this year.

Comparing Scenario 5 with Scenario 3

Both scenarios assumed High RE generation. But while Scenario 3 assumed Mid fuel price-escalation, Scenario 5 assumed High fuel price-escalation. Scenario 5 investigates the impact of High fuel price-escalation

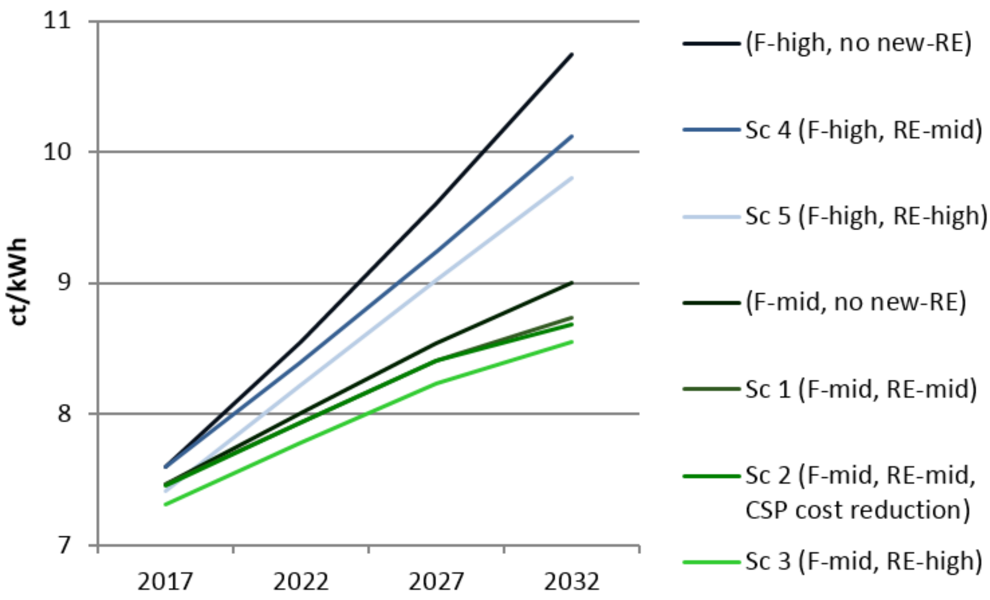

Figure 4.18: Comparison of average specific generation cost

on the results. In Scenario 5 more than ca. 7 GW of wind is introduced in 2027 compared with only 0.7 GW in Scenario 3, consequently the wind generation share is increased in 2027 from 19% in Scenario 3 to 25% in Scenario 5. It is also noticeable that 7 GW of CSP is introduced in 2032 that contributes to 8.8% of the generation share at this year, and replaced the 10 GW PV installed capacity introduced in 2032 in Scenario 3.

Comparing average system cost of all scenarios

The average specific generation cost of the system is defined as the total system cost (including the capital cost of all newly build plants during this year, all plants' operation and maintenance expenditures, and total fuel cost) divided by the total generated electricity at the respective year. Figure 4.5 shows the average system cost according to all scenarios, while figure 4.6 shows the relative total system cost over the planning horizon with Scenario 1 as reference state.

For the scenarios with Mid fuel price-escalation assumption (Scenario 1, Scenario 2, and Scenario 3) the average system cost varies from 7.3-7.5 ct/kWh in 2017 to 8.6-8.7 ct/kWh in 2032. It is worth mentioning that

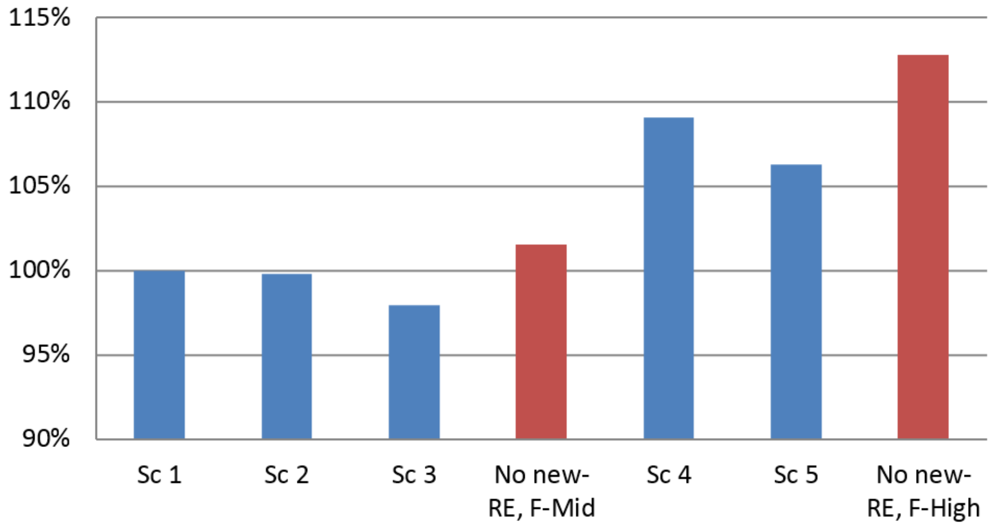

Figure 4.19: Relative total system cost over the planning horizon with Scenario 1 as reference state

if no new RE added after 2012, then the average system cost would then vary from 7.5 ct/kWh in 2017 to 9.0 ct/kWh in 2032. For the scenarios with High fuel price-escalation assumption (Scenario 4 and Scenario 5) the average system cost varies from 7.4-7.6 ct/kWh in 2017 to 9.8-10.1 ct/kWh in 2032. It is worth mentioning that if no new RE added after 2012, then the average system cost would then vary from 7.6 ct/kWh in 2017 to 10.7 ct/kWh in 2032. It is noticeable that the scenarios with High RE generation assumption lead to lower average system cost compared with the scenarios with Mid RE generation assumption (i.e. Scenario 3 compared with Scenario 1 and Scenario 5 compared with Scenario 4).

Regarding the relative total system cost, the scenarios with Mid fuel price-escalation assumption (Scenario 1, Scenario 2, and Scenario 3) show values between 98%-100%, while if no new RE added after 2012 then the relative total system cost would be increased to 102%. The scenarios with High fuel price-escalation assumption (Scenario 4 and Scenario 5) show relative total system cost values between 106%-109%, while if no new RE added after 2012 then the value would be increased to 113%.

5 Conclusions

This chapter presents the research conclusions and some future recommendations.

The optimization of capacity expansion for Egypt's power system has been conducted for a 20 year time frame starting from the status of the year 2012 (the last year with accurate data provided by the utility). The capacity expansion has been optimized for the planning milestones 2017, 2022, 2027, and 2032.

The main conclusions of this study, based on the applied input data, are:

- Nuclear option is economically unfavourable
- Using imported coal is economically unfavourable
- Not integrating further RE will lead to higher average system cost in the future
- CSP capital cost reduction is required to foster earlier CSP integration
- High fuel price-escalation assumption would favour faster RE integration
- Wind power and PV are the largest RE contributor to the generation dispatch (Scenario 1)
- Wind power and CSP are the largest RE contributor to the generation dispatch (Scenario 2)

Nuclear option is economically unfavourable

It is worth mentioning that the nuclear alternative is not contributing to the least system cost under Mid or High fuel price-escalation assumption. The deployment of nuclear energy in Egypt is economically unfavourable. Egypt is not expected to be technically capable or politically allowed to enrich and handle significant amount of uranium in such currently turbulent region. So in the light of the current political, economic, technical, security dimensions in Egypt and in the MENA region, the deployment of the nuclear energy in Egypt seems unrealistic -at least within the time horizon of this study-.

Using imported coal is economically unfavourable

One of the very interesting results of this study that the coal has not been selected as a fuel that contributes to the least system cost at any year and under any circumstances throughout the planning horizon. It is worth mentioning that after the nuclear fuel, the coal is the cheapest fuel among the fuel portfolio. Even under High fuel price-escalation assumption when the gas price increases from 29 EUR/MWh_{th} in 2017 to 49 EUR/MWh_{th} in 2032 while coal price just increases from 15 EUR/MWh_{th} in 2017 to 25 EUR/MWh_{th} in 2032, imported coal still has not been selected to contribute to the minimum total system cost at any year. This is regardless the environmental drawbacks and without taking any externalities into consideration.

Not integrating further RE will lead to higher average system cost in the future

For the scenarios with Mid fuel price-escalation assumption, the average system cost varies from ca. 7.4 ct/kWh in 2017 to ca. 8.6 ct/kWh in 2032. It is worth mentioning that if no new RE added after 2012, then the average system cost would then vary from 7.5 ct/kWh in 2017 to 9.0 ct/kWh in 2032. For the scenarios with High fuel price-escalation assumption, the average system cost varies from ca. 7.5 ct/kWh in 2017 to ca. 9.9 ct/kWh in 2032. It is worth mentioning that if no new RE added after 2012, then the average system cost would then vary from 7.6 ct/kWh in 2017 to 10.7 ct/kWh in 2032.

Regarding the relative total system cost (relative to scenario 1) , the scenarios with Mid fuel price-escalation assumption show values ca. 99%, while if no new RE added after 2012 then the relative total system cost would be increased to 102%. The scenarios with High fuel price-escalation assumption show relative total system cost values ca. 108%, while if no new RE added after 2012 then the value would be increased to 113%.

CSP capital cost reduction is required to foster earlier CSP integration

The high initial capital costs of the CSP technology still the most significant factor for CSP adoption. Hence for CSP projects in Egypt to be economically feasible and consequently included amongst the least cost capacity expansion plans in the short to medium term, the reduction of the capital costs would be necessary in addition to participating in the carbon emissions trading and offering policy incentives (e.g. long-term power purchase agreements, feed-in tariffs or tax incentives).

The ESMAP study [30] concluded that activities corresponding to 60% of CSP plants' capital cost be achieved locally within MENA region within the coming decade. Given the Egyptian context at the present time, plant construction and civil works in addition to steel structures and non-CSP-specific components could be handled locally. Egypt is home of one the biggest glass processor in MENA region which could be interested in CSP mirror production in the future.

Scenario 2 investigates the impact of CSP capital cost reduction (by 20%) on the results (under Mid fuel price-escalation and Mid RE generation assumptions). In Scenario 2 more than 10 GW of CSP is introduced in 2032. It is worth mentioning that introducing CSP in 2032 (that contributes to the firm capacity as it includes back-up system) reduced the total installed capacity in 2032 from ca. 100 GW in Scenario 1 to ca. 90

GW in Scenario 2. Scenario 2 confirmed that reducing the CSP capital cost would be the major factor to make CSP as an economically feasible option (given that no restriction on the available amount of natural gas as long as it could be imported with forecast international market price). CSP capital cost is expected to be reduced in Egypt and MENA region as discussed in section 4.1.

High fuel price-escalation assumption would favour faster RE integration

Under Mid RE generation assumption, Scenario 4 assumed High fuel price-escalation, while Scenario 1 assumed Mid fuel price-escalation. In Scenario 4 more than 10 GW of PV is introduced in 2027. It is also noticeable that 1.1 GW of CSP is introduced in 2032 that contributes to 1.2% of the generation share at this year.

Under High RE generation assumption, Scenario 5 assumed High fuel price-escalation, while Scenario 3 assumed Mid fuel price-escalation. In Scenario 5 more than ca. 7 GW of wind is introduced in 2027 compared to only 0.7 GW in Scenario 3, consequently the wind generation share is increased in 2027 from 19% in Scenario 3 to 25% in Scenario 5. It is also noticeable that 7 GW of CSP is introduced in 2032 that contributes to 8.8% of the generation share at this year, and replaced the 10 GW PV installed capacity introduced in 2032 in Scenario 3.

Wind power and PV contributions to the generation dispatch (Scenario 1)

The midday-peak and the evening-peak which are served mainly by GT and ST plants (fired by expensive gas) in 2017 would be replaced mainly by wind plants until 2027, and by 2032 PV plants would contribute significantly during the midday-peak. It is also very clear that wind power contributes significantly to the generating mix through the day, so wind power is used as a cheap fossil fuel saver due to its low generation costs (especially at the well-selected hot spots).

As CCGT usually cover the base load, many CCGT plants have up to

8760 FLH and their LCOE ranges between 6 and 10 ct/kWh. The PV plants have around 2000 FLH, while the wind parks have between ca. 3000 and ca. 4000 FLH. The LCOE of both PV and wind plants ranges between 6 and 8 ct/kWh.

Wind power and CSP contributions to the generation dispatch (Scenario 2)

The midday-peak and the evening-peak which are served mainly by ST and GT plants (fired by expensive gas) in 2017 would be replaced mainly by wind plants until 2027, and by 2032 CSP plants would contribute significantly during both midday-peak and evening peak in addition to a small contribution from PV during midday-peak. It is worth mentioning that the CSP units are highly dispatchable as they are equipped with TES and BUS, so during morning hours the surplus thermal energy is stored in the storage system to be used during the evening hours when the power demand increases to reach its peak, making CSP (if their capital cost could be reduced by about 20%) a valuable option for Egypt's power supply system as it offers both firm and flexible power generation capacity. It is also very clear that wind power contributes significantly to the generating mix through the day, so wind power is used as a cheap fossil fuel saver due to its low generation costs (especially at the well-selected hot spots).

It is worth mentioning that for both Scenario 1 and Scenario 2 (with unit commitment constrains taken into consideration), the LCOE generated from CCGT increases from 7 ct/kWh in 2017 to 9 ct/kWh in 2032 (this is influenced by the expected escalation of the fossil fuel price), while the LCOE generated from renewables (wind, PV, and CSP) is stabilized around 7 ct/kWh from 2017 through 2032.

Future recommendations

This study could be considered as a first step towards investigating the role of RE into the future Egyptian power plant portfolio, yet the study could be improved through:

- conducting further sensitivity analyses would be highly recommend in order to increase the reliability of the results and to investigate the impacts of the input data uncertainties on the results
- accessing updated authentic information (from relevant Egyptian authorities) for making more accurate assumptions
- taking the influence of political targets for RE, future international aids for RE projects, and carbon trading into account
- taking into account more RE hot spots according to the interest of the Egyptian authorities
- expanding the horizon of the study until 2050 as this may lead to earlier RE integration to avoid the fuel price-escalation after 2032

Final remarks

Egypt is currently facing a sever energy challenge, since 2012 Egypt experiences frequent blackouts especially during summer months. So it is expected that Egyptian officials have realized that securing a reliable electricity supply at reasonable prices is a key factor to avoid further public frustration and to pave the road towards decent economic development in the future. A comprehensive modelling of different characteristics of the power generation technologies is required to reach the optimal integration of RE technologies into an existing power plant portfolio.

It was shown that, under different considered assumptions, introducing imported coal to the fossil fuel portfolio is economically unfavourable, the nuclear option also is found to be economically unfavourable besides that it seems even unrealistic alternative under the current national and regional conditions. So beside natural gas, only RE technologies could contribute to the least power system cost in the future. It was clear that a well-balanced mix of all available RE technologies would not only reduce the total and average power system cost in the future, but it would also foster Egypt's energy security by making Egypt more energy independent and less sensitive to possible fossil fuel price escalations and availability restrictions in the future.

Although the study concluded that RE technologies are competitive in Egypt in the short- to medium- term and their large-scale integration makes economic sense, a fundamental electricity market reform is required to stimulate investments in RE projects immediately. It seems that reaching an atmosphere of peacefulness in this country (which is located in a currently turbulent region) would be the first step towards providing the sense of security about future revenues of any future RE projects this sense of economic security is one of the most essential reasons to convince national and international private investors to invest their capital with reasonable interest rates.

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