Wind power integration in Egypt and its impacts on unit commitment and dispatch

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Abstract

Egypt is experiencing a high increase in power consumption due to rapid population growth. To meet this growing demand, a capacity expansion plan is made by the Egyptian government intending 7050 MW of extra wind power capacity to be integrated in the Egyptian power system. In the frame of an Ea Energy Analyses project on this topic, this master project has contributed to investigate the implications of these high shares of wind power on the Egyptian system. The project focusses on the interaction of the unit commitment constraints and high amounts of wind energy. The study was done using the Balmorel model to perform power system simulations. Relevant data on the Egyptian electricity system and on unit commitment parameters was gathered and critically evaluated. The Egyptian expansion plan was compared to 4 relevant scenarios to assess its performance. Results have showed that the Egyptian expansion plan does not have sufficient capacity to fulfil the renewable energy goal of 20% renewable production in 2020. To achieve this goal an doubling of wind capacity is needed. An expansion of the current transmission grid is necessary when the capacity expansion plan is implemented especially at high shares of wind power. Sensitivity analyses have shown that increasing the wind generation compared to the expansion plan with more than 25%, results in wind curtailment and a drop in the electricity price. The full load hours of the thermal power plants in the Egyptian system decreased significantly at these higher shares of wind power. It was shown that adding unit commitment to the power system simulations of Egypt has a small but significant effect on total system costs to 3.7%, in particular with higher shares of wind generation, as well as on the electricity price (17%). It was found that, when implementing unit commitment, a determining factor is the calculation time, which rises steeply with increased complexity or accuracy.

Acknowledgements

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Nomenclature

Abbreviation	Explanation
EEHC	Egyptian Electricity Holding Company
NREA	New and Renewable Energy Authority
BOOT	Buy, Own, Operate and Transfer
NG	Natural gas
DRC	Democratic Republic of the Congo
IPP	Independent Power Producers
BOO	Build, Own and Operate
FLH	Full Load Hours
EAPP	Eastern African Power Pool
VOW	Value Of Wind

CHAPTER 1

Introduction

As Egypt is currently experiencing both economic growth and a steep rise in population, resulting in a high average power consumption growth. In order to meet this growing demand, Egypt is exploring paths with increased shares of renewable energy, which focus mainly on wind power generation. An ongoing project conducted on this topic by EA Energy Analyses (Ea) (website: [1]) is named 'Wind power integration in Egypt' [2]. This thesis will contribute to the EA project and aims to focus on the unit commitment aspects of wind power integration. An earlier Ea study on the energy future of the whole of Eastern Africa, called 'Development of regional master plan in Eastern Africa' [3], was already concluded and is used as a basis for the study.
In this introduction chapter, the project outline of Ea's 'Wind power integration in Egypt' is explained as well as the specific focus of the master thesis. The conditions of the current Egyptian energy system are briefly described and the potential future developments are discussed based on the intentions of the Egyptian government and the wind potential in the country. The previous work and results of the 'Development of regional master plan in Eastern Africa' project are also discussed. A brief literature review is presented on a few relevant articles. Finally, the content of the remainder of the report is outlined briefly.

1.1 Wind power integration in Egypt

In the "Wind power integration project" by Ea, the consequences of installing an extra 7.050 MW onshore wind power by 2030 on top of the already existing and committed turbines are investigated. It is part of a bigger project that consists of three types of analyses that need to be performed to have a complete overview of the impacts of this investment in wind power.

- **An electrical analysis of the grid:** Ensure the reliability of the system based on load flow analyses and voltage control
- **A wind planning analysis:** Includes defining the wind potential of potential sites, environmental impact assessments and feasibility studies.
- **Overall energy system analysis:** Investigates the impacts on the energy dispatch and economic values such as the value of wind

It is on this last bullet point that the project in Ea Energy Analyses focusses. The changes in the power system necessary to take full advantage of the installed wind power is analysed. The Balmorel modelling tool has been chosen for this analysis (see next chapter).

1.2 Focus of master project

The present master project has contributed to the Ea-study by incorporating the by the Egyptian government intended expansions in wind power capacity in the Balmorel simulation model. As part of this project, the previously existing model has been improved to include unit commitment parameters that make the dispatch of generation units more realistic and accurate. The qualities and drawbacks of the future Egyptian energy system as it is intended to develop has have been examined by assessing its performance in certain key variables, among which the generation profile, the total system costs and the electricity price. The system has also been evaluated by comparing it to four other scenarios that differ in generation capacity and regional transmission capacity. The validity of the scenario results are tested by performing sensitivity analyses on certain relevant parameters. While examining the future power system in Egypt, special focus was given on the relevance of unit commitment simulation in scenarios with high shares of wind power and the interaction between wind generation increase and the unit dispatch of the remaining technologies.

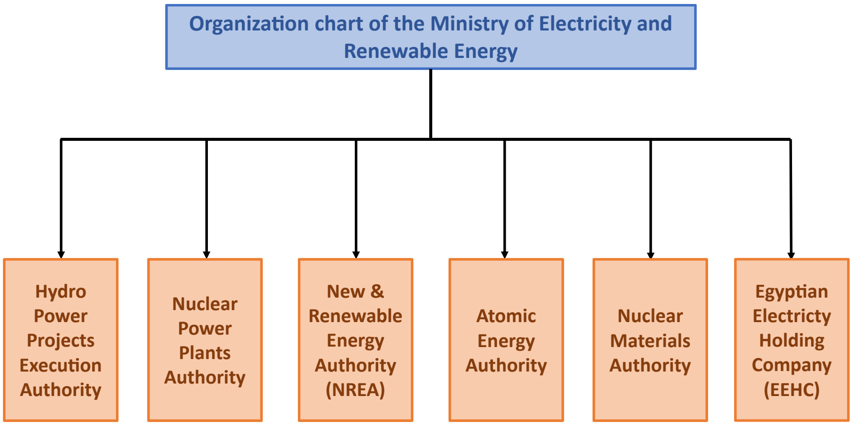


Figure 1.1: Organization of the power sector in Egypt

1.3 Current energy system in Egypt

The responsibility of the Egyptian electricity system rests with the Ministry for Electricity and Renewable Energy, which is organized in several energy authorities as seen in Fig. 1.1. Of those, the most important for this project are the Egyptian Electricity Holding Company (EEHC) and the New and Renewable Energy Authority (NREA). In Egypt the electricity system consists mainly of government-run companies. As such, there are six production companies, one transmission company and nine distribution companies under the control of the EEHC. (Fig. 1.2). The production companies own the large majority of the generation plants. Apart from those, a few generation plants are run by the private sector under the BOOT principle of Buy, Own, Operate and Transfer. In this financing scheme private companies are allowed to invest in production facilities, recover their construction costs and make profits for a fixed period of time after which they turn the plant over to the state [4]. The renewable generation facilities in the system are owned by the NREA. The total generation in 2013 is 165.6 TWh. The composition of the generation capacity is seen in Fig. 1.3 [5] in terms of generation fuel/technology and the plant companies and owners. It can be seen that in 2013 89% of the installed capacity is thermal generation based on natural gas (NG), i.e. 78.3% of total fuel consumption. The 2.2% renewable capacity totals at 687 MW and consists of a wind farm of 547 MW in Zafarana in the gulf of Suez and a solar-thermal plant of 140 MW. Hydro power 9.1% of the total capacity is hydro power. This amounts to

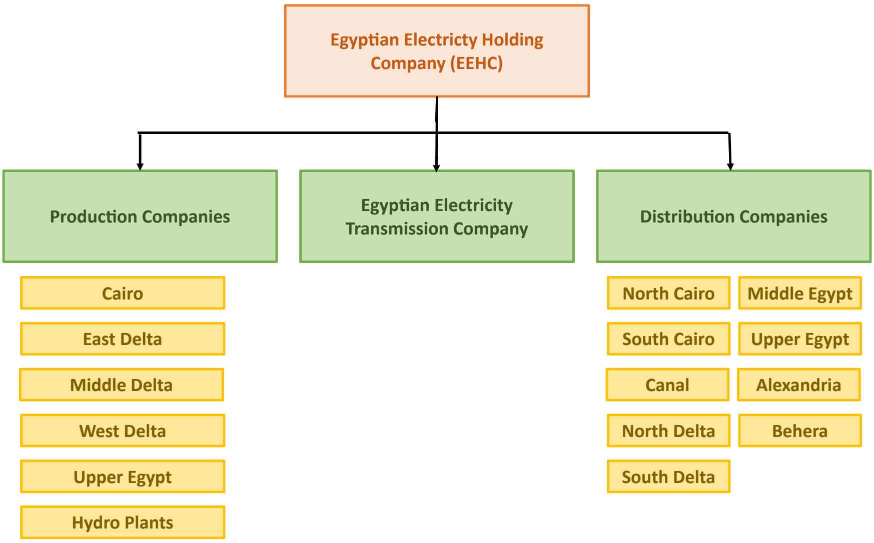


Figure 1.2: Organization of the government run energy companies [6]

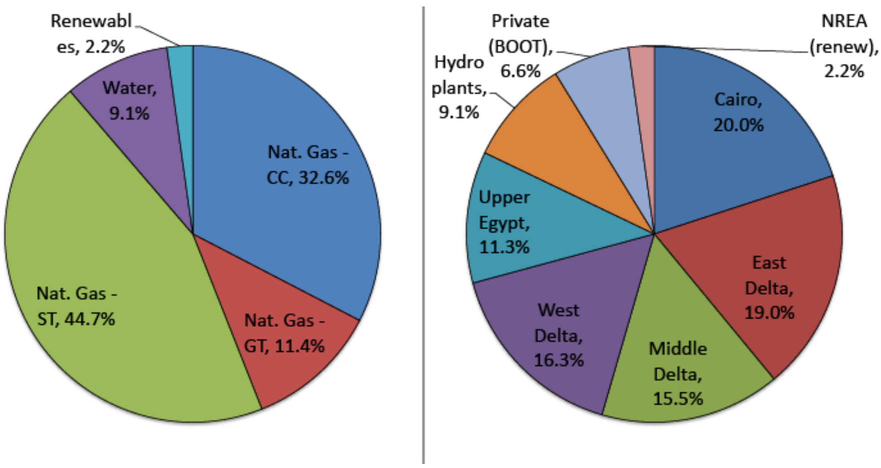


Figure 1.3: Composition of the Egyptian generation capacity of 2013 in terms of fuel (left) and companies (right) [5]

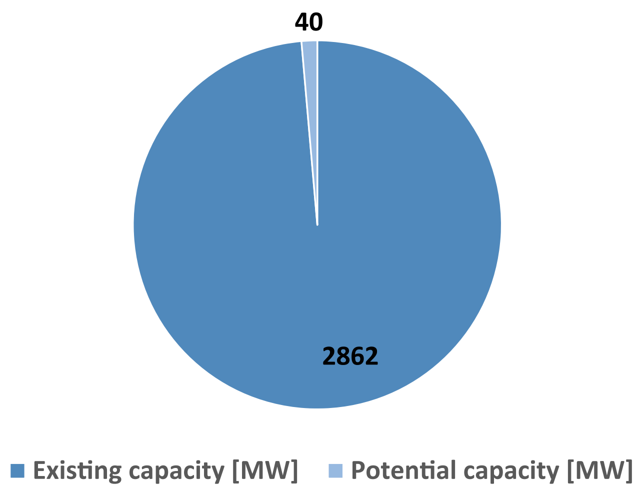


Figure 1.4: Hydro potential and installed capacity in Egypt [8, chapter 6]

about 2800 MW and is almost the country's full hydro potential (Fig. 1.4). In 2013 Egypt is connected both to Libya an Jordan with transmission capacity of respectively 240MW and 600MW [7].

1.4 Future energy system in Egypt

The development of an adequate Egyptian power plan is done by the Ministry for Electricity and Renewable Energy. The Egyptian annual electricity demand is rising sharply (from about 200 TWh in 2015 to an expected 378 TWh in 2025 with peak demand of 30 GW and 60 GW respectively) Therefore the power plan includes a large expansion of the current generation capacity (more details in section 3.2.3). While the energy plans foresee a great increase in thermal capacity fuelled by NG, also investments in coal and nuclear power are expected. Efforts are made to include renewable energy generation facilities in the energy mix as well.

1.4.1 Renewable Energy Development Program by 2020

Aiming to diversify energy resources and limiting climate change the ambitious goal of 20% renewable energy generation by 2020 has been set by the Egyptian supreme energy council in 2008, NREA annual report. This 20% of green generation is planned to consist of 6% hydro power, for the most part already operational in 2013, 2% solar energy and 12% wind power. [9] The 12% wind power, which translates into 7.050 MW capacity is intended to be financed for one third by public investments from the NREA aided by international financing and two thirds by private investments realized by a combination of energy incentives:

- **Competitive bids (starts August 2009):** an international request is made for tenders of the private sector to provide power through wind energy projects
- **Feed-in tariffs (starts August 2009):** based on the price of electricity found in the competitive bids, a feed-in tariff is set
- **Third party access (starts June 2012):** independent power producers (IPPs) are allowed to build, own and operate (BOO) a power plant in order to provide in their energy demands or to sell to the grid
- **Land reserved for wind farms**: About 7647 km^2 of land at the Suez Gulf and the East and West banks of the Nile have been allocated for the erection of these wind farms [5].

1.4.2 Wind power potential in Egypt

In 2005 a wind Atlas was developed for the whole of Egypt, [10]. This was done based on observations in 30 wind stations in Egypt and on a numerical model where a mesoscale model was used and long term-data was re-analysed. The wind atlas shows that besides the already uncovered very high wind region in the Gulf of Suez and Aquaba with 8-10 m/s average wind speed, the large regions on both sides of the Nile in the Western desert have fairly high wind resource (average wind speed of 7-8 m/s) and are closer to the consumers and the electricity grid, see Fig. 1.5. [5]

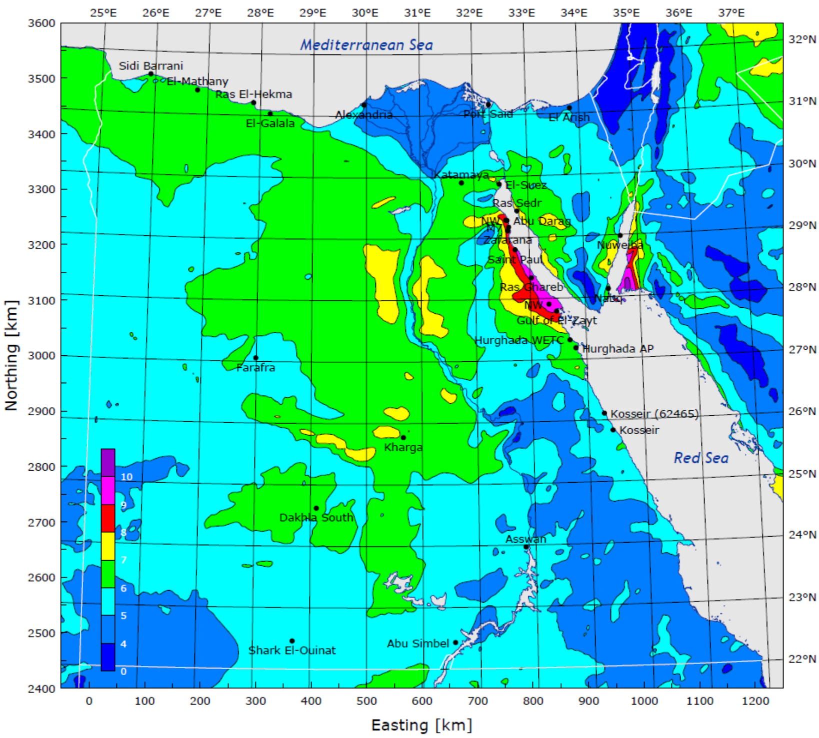


Figure 1.5: Wind atlas for Egypt [10]

1.5 Previous work: Development of regional master plan in Eastern Africa

The aim of the 'Development of regional master plan in Eastern Africa' project was to develop a master plan for investments in the electricity system based on regional cooperation. The project was concluded December 2014 in a cooperation of EA with Energinet.dk. An analysis was conducted on 10 countries that are member of the Eastern African Power Pool (EAPP): Libya, Egypt, Sudan, Ethiopia, Kenya, Tanzania, Uganda, Rwanda, Burundi and DRC (Democratic Republic of the Congo). For modelling purposes also South Sudan and Djibouti were added to the simulations. Due to economic growth, the electricity demand in these countries is growing rapidly. [11] The general trends in the final results for the whole Eastern African area are a big increase in fossil fuel based power generation (natural gas and later on coal) and a doubling of hydro power in 2020 compared to 2015. For Egypt natural gas is expected to continue to be the dominating fuel up until 2025 at about 89% of the total capacity in 2025. No investments in other fuel were made in the model used in the project. The master plan also recommends the extension of the transmission capacities between the Eastern African countries. For Egypt the recommended increase from 2015 to 2025 is 1000 MW capacity with Sudan and an extra 200 MW on its transmission line with Libya (see Fig. 1.6) [12]. A 200 MW transmission line to Sudan is committed as a project. [5]

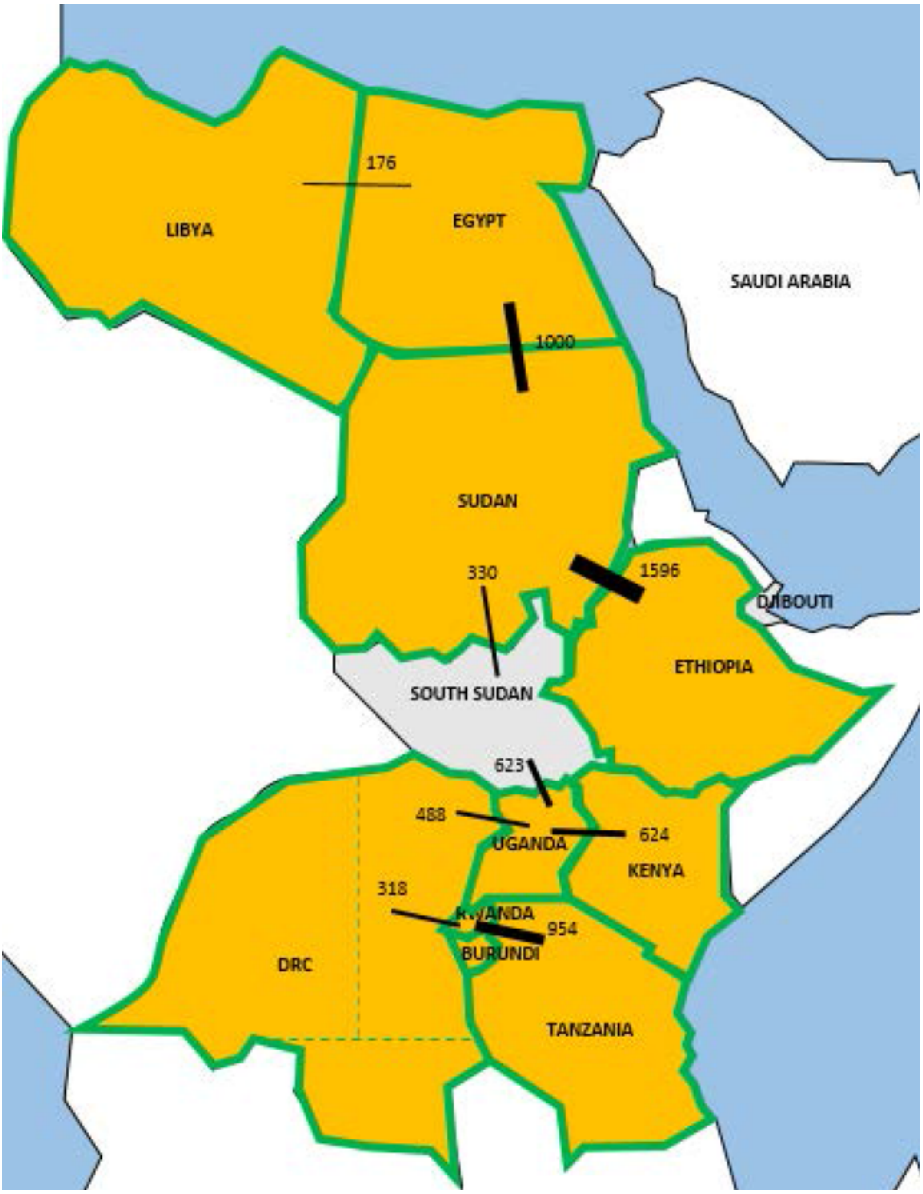


Figure 1.6: Simulated countries and transmission capacity increase by 2025 compared to 2015 (connection capacities in MW) [11]

1.6 Literature review

Many studies have been performed on topics related this project. The results of one study on the viability of wind power integration in Egypt is described here, along with the selection of articles on the impacts of high wind power shares on unit commitment.

1.6.1 Wind integration in Egypt

An important aspect for wind integration in Egypt is the stability of the grid frequency. A study was done on the performance of the Egyptian system after including a medium amount of wind power generation [13]. The results showed that the system operation did not experience problems and frequency drops remained above the acceptable level.

1.6.2 Impacts of wind integration on unit commitment

The impact of wind power integration on unit commitment is the topic of several studies found in literature. One of the recurring topics in many articles is the integration of the unpredictability of the wind power (as well as the load) into simulation models. The concern is that simple models do not take the changing wind forecasts into account as they move closer to the production moment, at which point thermal unit commitment constraints can create an issue. In [14], a stochastic method based on time-varying quantiles was incorporated in the simulations to improve the robustness of one such simple model. The consequences of the overestimation of wind power at production time depend highly on the circumstantial factors, as was shown in their numerical examples. In [15], a decrease of 0.25% in system costs was found when using stochastic optimization compared to a deterministic approach. It was also found that the biggest impact of the uncertainty of wind is on peak generators and transmission lines. Article [16] also considers the difference between foreseen and predicted wind speeds. Unit commitment constraints as minimum load, ramp-rates for generation and for reserve activation, minimum up and down time were implemented. The assessment of the forecasting error was tested in a realistic Dutch power system and shows to have very little impact on the unit dispatch. Some small amounts of curtailed wind are encountered (about 3% of generation without curtailment) at 8 GW wind power integration.
Another point of interest in literature is the investment optimization and expansion planning with UC. The option to include UC parameters in the investment

optimization is explored in [17]. Using a method to shorten the calculation times of investment runs with UC by grouping generators in categories, the conclusion was found that a sub-optimal capacity mix could results in 17% higher operation costs compared to optimal solution obtained by the new method. The sub-optimal result lacked the flexibility needed with increased wind power generation.

1.7 Content of the thesis

In the remainder of the thesis, results and conclusions of the master project are described. In the following chapter, the requirements for the simulation model are set out and the used model is characterized. The advantages and drawbacks of the model are discussed. A chapter on the inputs for this model and the associated assumptions follows. At this point, the set-up of the scenarios used is described as well. The fourth chapter contains the results of the scenario simulations accompanied by the explanation of how they came to be. To test the quality and robustness of the results obtained, sensitivity analyses are performed and reported in the validation chapter. A discussion chapter follows to put the main results in perspective. Lastly the thesis ends with a short conclusion on the project, its results and significance.

CHAPTER 2

Method: Balmorel as a simulation tool

Application of an appropriate energy tool is an important aspect of the master project. This chapter elaborates on the requirements of this tool and the justification of the choice. The chosen tool is shortly introduced and described using some of the underlying mathematical formulas most relevant to the simulations in this project. Finally, the limitations of the model are discussed.

2.1 Energy tool portfolio

Since energy system analyses are of paramount importance for informed decision making, many energy modelling tools exist. The functionality of these tools can differ in multiple respects and few of them are suited for all purposes. In order to select the appropriate energy tool for a certain project it is necessary to be informed of its specific properties and functionalities. In this paragraph some classifications of energy tools are described. The types described here are found in [18] where many more energy tools are listed and categorized.

A first division amongst energy tools can be made based on these modelling types:

- **Simulation tools:** The very operation of an energy system is simulated by optimization, based on specific information on the external system conditions, usually on hourly base.
- **Scenario tools:** The evolution of the energy system is modelled over a period of about 20-50 years in a well-defined scenario. The time-step is often a year.
- **Top-down tools:** Based on macroeconomic data, the trends of variables as the demand and the prices are determined
- **Bottom-up tools:** Starting from the individual energy technologies and small scale parameters the energy system is modelled with great detail
- **Operation optimization tools**: The operation of the energy system is optimized under given external conditions.
- **Investment optimization tools:** The investment in new generation technologies and transmission capacities is optimized for set scenarios.
- **Equilibrium tools:** The economic equilibrium is found based on the behaviour of the supply, the demand and the prices.

For the purposes of this master study on wind power integration and unit commitment, the energy modelling tool needs to classify as a simulation and scenario tool in order to have both a detailed insight in the generation profile and a long term view on the evolution of the energy system in certain scenarios. In order to implement unit commitment parameters on the generation units, the tool requires bottom-up modelling starting from individual power units. Operation optimization allows for correct unit commitment simulation, which should be based on equilibrium optimization. Investment optimization is advantageous for setting up future energy scenarios based on least-costs planning.

A few other important properties for energy tool are listed here.

- **Geographical scope:** This can go from an area, a region or state to a more international or even global extent
- **Maximum time-frame:** The amount of years for which the model can be used, if it is not limitless.
- **Minimum time-step:** The smallest time resolution the tool uses. This can be from seconds to years.
- **Energy sectors:** Which of the three energy sectors are considered: electricity, heat and transport.

The simulations in the master project are focussed on the electricity sector of Egypt, so on country level. The required timespan of the simulations is 16 years (from 2015 to 2030) . It is necessary to have at least an hourly time resolution, to implement unit commitment parameters as ramp-up time or minimum on time.

2.1.1 Balmorel model characteristics

Based on these requirements, the Balmorel modelling tool is an appropriate fit for the simulations performed in the project. The Bamorel model classifies as both a simulation tool and a scenario tool due to the great variability of the time steps and simulation periods. Input properties of the energy system are included in the model with a high level of detail. Specific parameters for individual generation facilities are all considered in order to describe the system constraints. Therefore the model is considered a bottom-up energy tool. Balmorel is both a operation and an investment optimization tool. When optimization the hourly operation it is an equilibrium tool. The investment optimization does not always reach an equilibrium as it is not possible to change the exogenous (manually entered input) generation or transmission in the optimization of endogenous (chosen by the model) capacities.

Balmorel has an international geographical scope (see Fig. 2.1), though there is no limit on the potential extension of this area. The time-frame for the model is 50 years with hourly time-steps (minutes and seconds can also be used but are not common). The electricity sector is considered entirely in the model. The heat sector is only modelled when district heating is concerned. The transport sector was not initially included in the model, though some add-ons are developed to include it to some extent.

2.2 Introduction to Balmorel

In this project simulations of the Egyptian energy system will be performed in the energy modelling tool Balmorel. The 'Baltic Model of Regional Electricity Liberation' or Balmorel is an open-source model originally developed by Elkraft, the former Danish transmission system operator which is now Energinet.dk. It was developed with the objective to analyse the electricity and CHP sector of the Baltic Sea Region for long term planning. The model comprehended the international context of this analysis while achieving a high degree of detail. It offered the option to execute analyses in both long and short term, on a regional,

national or international scale, [19].
Since then the model has undergone many adaptations and improvements to extends its functionality further. Balmorel has been used to perform analyses in a wide variety of regions (e.g. North Europe, Mexico, South Africa, Western Africa and China, see Fig. 2.1) with its main applications in:

- Market analysis
- Energy policy analysis
- Analysis of technical and economic feasibility
- Operational analysis
- Scenario analysis

Some examples of recent projects and theses can be found on the Balmorel website [20] and among the Ea projects [1].

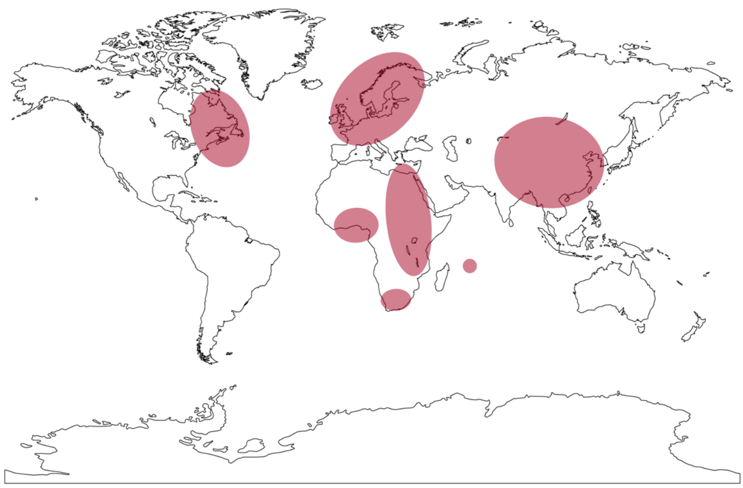


Figure 2.1: Regions subject to active or completed Balmorel projects

2.3 The mathematics behind the Balmorel model

The Balmorel model is based on the least system costs optimization principle. It is written in the GAMS modelling language (General Algebraic Modelling System) that specializes in modelling linear, non-linear and mixed integer optimization [21]. The basic Balmorel model exists as an extensive linear programming (LP) problem. The general outline of the mathematics behind these kind of problems is documented here. For a more detailed and practical description of how the model is developed and coded in GAMS, one can consult [19], [22] and [23].

2.3.1 Introducing the linear programming problem

In this section the basic principles of LPs are explained and the terminology is introduced. A LP problem is an optimization of a linear objective function, conform to linear constraints. In linear programming deals with the planning of how a number of resources are optimally allocated to a set of activities. [24] For m different resources and n activities the LP problem can be written in its standard (canonic) form as

$$\text{Maximize} \quad Z = \sum_{j=1}^{n} c_j x_j \tag{2.1}$$

$$\text{Subject to} \quad \sum_{j=1}^{n} a_{ij} x_j \leq b_i \quad \forall \text{ i } \in \{1,...,\text{m}\} \tag{2.2}$$

$$x_j \geq 0 \quad \forall \text{ j } \in \{1,...,\text{n}\} \tag{2.3}$$

Here Z is the objective to be maximized; x_j is a decision variables and represents the level of the activity j. The parameters c_j, b_i and a_{ij} represent the contribution of a unit increase in activity x_j to the objective Z (c_j), the availability for allocation of resource i (b_i) and the amount of resource i used for a unit increase of activity level x_j (a_{ij}). Eq. 2.1 are the objective functions. The two types of constraints are the structural constraints (Eq. 2.2) and the non-negativity constraints (Eq. 2.3).

2.3.2 Solutions to the LP problem

Any set of values for the decision variables x_j is called a solution to the LP problem. These solutions can be further categorized in three groups:

- **An infeasible solution:** a solution that violates one or more of the constraints
- **A feasible solution:** a solution that satisfies all constraints
- **An optimal solution:** a feasible solution that optimizes the objective function

It is possible for a LP problem not to have any feasible solution in which case no optimal solution can be found. If there are feasible solutions there can be

- One optimal solution
- An infinite number of optimal solutions
- No optimal solution due to an unbounded objective (meaning that the objective can be increased infinitely so no maximum can be found)

2.3.3 Variations on the standard form

Some variations on the standard LP problem exist. They can be transformed back to the standard form to prove they are in fact only different formulations of the original LP problem.

- **Objective function:** minimization instead of maximization.
- **Structural constraints:** '$\geq$' or '$=$' instead of '$\leq$' constraints.
- **Non-negativity constraint:** '$\in \mathbb{R}$' instead of '≥ 0'.

2.3.4 Balmorel equations

The Balmorel model is an extensive linear programming problem where the objective function is the total system costs which the model minimizes for a specific set of input parameters. This objective function takes among others the following costs into account:

- Fuel costs
- Operation and maintenance costs (both variable and fixed)
- Investment costs (both in transmission and generation capacity)
- Taxes

The model is subjected to a great number constraints of which the following are the most relevant for the presented project. For all hours these constraints are implemented

- Electricity generation $=$ Electricity demand
- Fuel consumption $= \frac{\text{Electricity generation}}{\text{efficiency}}$ for all generators

- Generation of fluctuating renewables ≤ Available generation (e.g. wind/solar/hydro/wave profile)

- Electricity transmission ≤ Transmission capacity

- Policy restrictions

2.3.5 Solving the LP problem

Several solvers are available for Balmorel and GAMS to solve the linear programming problem. The one used in this project is the CPLEX solver. It implements the so called simplex method, an algebraic iterative procedure for solving LP problems. At the base of the simplex method lies the concept of corner-point (CP) solutions. These are feasible solutions at the corners of the feasible region of the problem (defined by the constraints). CP solutions are called adjacent when they share n-1 constraint boundaries, n being the amount of decision variables. The line connecting two adjacent corner-point solutions is defined as an edge of the feasible region. It an important theorem that if an LP problem has one optimal solution it will always be a corner-point solution. If there are multiple optimal solutions at least two of them are corner-point solutions.
The simplex method uses this theorem and implements a method to find the optimal solution in an efficient way. The simplex method algorithm consists of the following steps:

- **Initialization**
  First a CP solution is chosen as a starting point. This is often the origin (solution for which all decision variables are 0).
- **Optimality test**
  In this step it is determined whether or not the current CP solution is an optimal solution. For this purpose the solver considers all edges between the current CP solution to the adjacent ones. Then the rate of improvement of the objective is calculated(increase for an maximization problem and decrease for a minimization problem). If the objective does not improve along any of the edges the current CP is and optimal solution.
- **Iteration**
  If the current CP point proves not to be the optimal solution, the CP solution with the highest rate of improvement on its edge with the current CP solution is chosen as the next one to consider.

2.4 The mathematics of the Unit Commitment add-on

2.4.1 Introduction to the mixed integer problem

Up to this point the generation units have been considered as simplified entities that can produce at any power level between zero and the maximal capacity. The costs involved are linearly related to this power generation through the fuel efficiency. This type of representation is called an economic dispatch problem and can be written as the following LP [25]

$$
\begin{aligned}
\text{Minimize} \quad & Z = \sum_{t \in T} \sum_{j \in J} a_{jt} f_{jt} && && (2.4)\\
\text{Subject to} \quad & \sum_{j \in J} p_{jt} = d_t && \forall \text{t} \in \text{T} && (2.5)\\
& p_{jt} \leq p_j^{max} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.6)\\
& f_{jt} = \tfrac{p_{jt}}{\epsilon_j} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.7)\\
& p_{jt} \leq 0 && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.8)
\end{aligned}
$$

Here T $= \{1, ..., t_m\}$ and J $= \{1, ..., j_n\}$ are enumerations of the time segments t and the units j respectively. For a plant j in time segment t, a_{jt} represents the fuel price per fuel consumption unit, f_{jt} is the fuel consumption and p_{jt} is the electricity generation. The demand at time t is written as d_t and ϵ_j is the fuel efficiency of unit j.
When the unit commitment add-on is included in the Balmorel model, extra constraints can be added to the simulation to make the simulation more realistic. The following considerations can be modelled.

- Minimum generation level
- Ramping times (start-up rate)
- Start-up costs
- Fixed fuel consumption
- Minimum on and off times

The unit commitment (UC) LP problem then becomes a more complex set of equations

$$\begin{aligned}
\text{Minimize} \quad & Z = \sum_{t\in T}\sum_{j\in J}(a_{jt}f_{jt} + c_j v_{\uparrow jt}) && && (2.9)\\
\text{Subject to} \quad & \sum_{j\in J} p_{jt} = d_t && \forall \text{t} \in \text{T} && (2.10)\\
& p_j^{min}u_{jt} \leq p_{jt} \leq p_j^{max}u_{jt} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.11)\\
& f_{jt} = \frac{p_{jt}+f_{0,j}\left(p_{jt}^{max}u_{it}-p_{jt}\right)}{\epsilon_j} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.12)\\
& v_{\uparrow jt} - v_{\downarrow jt} = u_{jt} - u_{j(t-1)} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \geq 2 \in \text{T} && (2.13)\\
& \sum_{t'=t-o_j+1}^{t} v_{\uparrow jt'} \leq u_{it} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \geq o_j \in \text{T} && (2.14)\\
& \sum_{t'=t-d_j+1}^{t} v_{\downarrow jt'} > u_{it} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \geq d_j \in \text{T} && (2.15)\\
& p_{jt} - p_{j(t-1)} \leq r_{\uparrow j} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.16)\\
& p_{j(t-1)} - p_{jt} \leq r_{\downarrow j} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.17)\\
& p_{jt} \leq 0, u_{jt}, v_{\uparrow jt}, v_{\downarrow jt} \in \{0{,}1\} && \forall \text{j} \in \text{J} \ \& \ \forall \text{t} \in \text{T} && (2.18)
\end{aligned}$$

In this unit commitment extension to the economic dispatch problem there are three extra decision variables: u_{jt} is the on/off status and $v_{\uparrow jt}$ and $v_{\downarrow jt}$ are the start-up status and the shut-down status respectively. These are not linearly continuous but binary variables. The objective function is expanded with c_j the start-up cost of unit j. Eq. 2.11 now includes a minimum generation p_j^{min}, preventing the plants from operating at very low generation. The on-line cost of a unit j is added to the problem as an additional fixed fuel use $f_{0,j}$ in Eq. 2.12. This parameter expresses the fuel use of a plant j with an on-line state as a ratio with the fuel use at full capacity. The efficiency of the plant is then changed to the marginal efficiency as shown in Fig. 2.2, meaning that the effect of the fixed fuel use decreases when a unit operates close to full capacity. Eq. 2.13 relates the on/off states of the plants to the start-up and shut-down variables. Eq. 2.14 and 2.15 are the constraints implementing the minimum up (o_j) and down (d_j) time respectively. Finally the ramp up ($r_{\uparrow j}$) and down ($r_{\downarrow j}$)times are insured by Eq. 2.16 and 2.17. Including the first considerations does not change the nature of the problem. However the start-up costs, the fixed fuel consumption, the minimum on/off time and ramping constraints introduce new variables which have to be integer (binary in this case). This changes the problem from an LP problem to a mixed integer programming (MIP) problem (mixed since the variable f_{jt} remains a continuous variable).

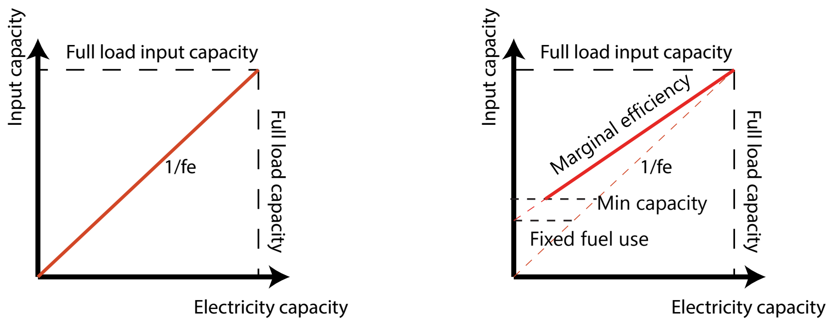


Figure 2.2: Fuel use versus generated electricity without (left) and with (right) fixed fuel use included

2.4.2 Solving the mixed integer problem

Introducing integer variables in the LP changes the nature of the problem to the extent that the simplex method cannot solve it any longer. The complexity of the MIP problem shows exponential increase with the number of integer variables. The technique for solving MIPs is called branch-and-bound. This is a procedure that enumerates the finite number of feasible solutions in a structured manner. The solutions are divided in sub groups to simplify the problem. This iterative method deploys the following steps performed in each iteration.

- **Branching**
  Divide the problem in sub-problems by setting the value of one of the integer variables to all the options available in the feasible region (e.g. u_{11} = 0 and 1 in the UC problem, two sub-problems are created).
- **Bounding**
  For each sub-problem solve the relaxed LP problem (where all the unfixed variables are linearly continuous) with the simplex method. This forms an upper bound (or lower bound in case of minimization) for the optimal MIP solution. Certain smart mathematical algorithms (deployed by GAMS) can make this bound even stricter based on input parameters.
- **Fathoming**
  Dismiss sub-problems when they fulfil one of these conditions: a) the bound is worse than the current best MIP solution, which is called the incumbent and initialized at $-\infty$ ($+\infty$ for minimization) b) the relaxed

LP problem has no feasible solutions. In case the relaxed LP is an integer solution which is better than the current incumbent, make it the new incumbent and perform condition a) on all unfathomed sub-problems under considerations.

This iteration is continued by subdividing sub-problems and thereby forming a solution tree. The problem is solved when no remaining sub-problems exist. The incumbent is then the optimal solution.The CPLEX solver of GAMS uses this branch-and-bound method to solve the MIP when unit commitment is included.

2.4.3 Approaching the mixed integer solution in Balmorel

The Balmorel model including UC is a very extended representation of this MIP problem. Since the complexity increases exponentially with the number of binary variables, the calculation times for a unit commitment problem can be a limiting factor. A way around this is to allow a certain inaccuracy on the solution. This allows the calculation times to stay limited. In Balmorel it is possible to set a value on the allowed inaccuracy of the objective function. When the best MIP solution and the strictest relaxed LP solution differ by this value, the MIP solution is assumed sufficiently accurate. The inaccuracy can be defined as an absolute number or as a percentage of the objective function.

2.5 Limitations of the Balmorel model

Now that the working principles of the Balmorel model are understood, it is necessary to dig into the limitations of the model. As it is a simulation tool, the model aims to imitate a realistic outcome under certain input conditions. There are however a few factors limiting the performance accuracy.

Input uncertainty The Balmorel model works with a wide range of input parameters being fed to the LP problem which are used as a starting point for the calculations. It is obvious that these input parameters suffer from a certain degree of uncertainty, especially when they represent predictions for the future. Inputs as the fuel prices or the generation efficiency improvements for example are dependent on a range factors that therefore make them difficult to predict. Changes in these parameters could induce changes in the least costs solutions found by Balmorel.

Perfect competition The Balmorel model assumes a perfectly liberated market,or perfect technological planning where the supply and demand curve determine the spot price. For perfect competition it is among other things important that there is a large number of seller and buyers of which non are large enough to have any market power, that no barrier for entering the market should exists and that there is perfect information on the market. In perfect technical planning the system is designed by people with perfect insight in the dynamics of the energy system.These requirements are not completely fulfilled in any energy market however.

Perfect foresight in dispatch optimization The model optimizes the dispatch problem for certain time periods in which it assumes perfect foresight. This implies the model know exactly what the external conditions of the energy system are in every hour in this period. In reality the unpredictability of parameters as hourly demand, hydro power water inflow and wind speed are a big factor in the functioning of the energy system.

Short-sighted investment optimization For the investment simulation, the Balmorel model considers each year individually and decides on the necessary investment in generation of transmission capacity without considering the conditions of the future energy system.

Partial equilibrium for investment optimization While the model includes investment optimization, the endogenous (computed by the model) developments have no impact on parameters of the exogenous input (inserted by the user of the model). The model thus finds an equilibrium.

Power grid properties not included The voltage considerations are not included in the Balmorel simulation. In the real-life energy sector, grid balancing is of great importance and the Kirchoff laws need to be complied by at all times. A structure of primary reserve, second reserve and black-out reserve is set-up to avoid issues. In Balmorel these considerations are not modelled.

Chapter 3

Input data and scenario description

3.1 Introduction

For realistically simulating the Egyptian electricity system a great amount of input data is needed. Information on demand, the energy mix and the corresponding plant parameters as well as transmission capacities, fuel prices and economical growth in Egypt is important data for the model. A completely accurate simulation of the Egyptian electricity system is not achievable as it would require an enormous amount of very accurate data and a model that is a perfect representation of reality. Therefore, a simplified version of the system is modelled, where the parameters are a good representation of the reality but with a lower degree of complexity. When evaluating future scenarios an extra factor of uncertainty is added to the difficulties of accurate simulation. Input data concerning the future are then based on extrapolations of trends and grounded predictions. In some cases required input data can be inaccessible for the public, in this case estimates based on the best available information and assumptions are used to approach reality.

As this project is based on the previous project in which a Master plan for the EAPP was studied (see 1.5) some general information on the Egyptian power system was already available and incorporated in the Balmorel model. As Egypt was only a fraction of the total simulation, it was not necessary to have a high level of detail on the Egyptian parameters in the EAPP project. In the Wind power integration in Egypt project hence in this thesis, however, more in-depth data was needed and was therefore gathered and added to the Balmorel input as part of the master project.

In the following section the main input parameters that are used in the model are described along with their assumptions and simplifications. These data are aimed to be as accurate as possible and includes a minimum of guesses. An explanation is also given on how hydro power is modelled and how model-based investment runs are simulated. In section 3.3, the description of five different energy scenarios is given. Here a "What if" approach is used and these scenarios are not necessarily aiming to represent any predicted future.

3.2 Input data and assumptions

In this section the input data for the Main scenario (for a definition see section 3.3.1). The data sources are mentioned and input assumptions are described.

3.2.1 Regions

One of the ways the Egyptian power model is made more detailed in this master project compared to the earlier EAPP version is by dividing the "copper plate" Egypt into geographical regions (see Fig. 3.1). These regions are based on the six production companies in Egypt [5] each owning a set of power plants linked by their location. The production company "Hydro Plants" was merged with Upper Egypt, since all hydro plants are upstream on the Nile river, making the total number of regions to five. There were a number of obvious options for dividing the Egyptian power system in regions. The division could be based on the six production companies, the nine distribution companies or the seven zones used by the transmission company (Fig. 1.2. The choice to base the regions on the production companies is motivated by the fact that it is easier to allocate higher resolution data over the fewer categories than vice versa.

Figure 3.1: The five regions in the Egyptian power system and their interconnections

Table 3.1: Demand distribution over the Balmorel regions

Region	Share
Cairo	31.2 %
East-Delta	16.9 %
Middle-Delta	23.0 %
Upper-Egypt	19.4 %
West-Delta	9.5 %

3.2.2 Electricity demand

The historic and predicted future annual demand in Egypt were already included in the Balmorel model during the EAPP project (see Fig. 3.2) and were based on the EEHC forecast up until 2026. For the years after an extrapolation was made. In order to allocate this demand over the different regions, data from the Egyptian transmission company was used. Here a momentary load distribution was given for a high and a low demand case in both 2014 and 2015. This information was averaged and the relative shares were used to divide the total Egyptian demand. As there are 7 transmission zones they were each assigned to one of the Balmorel regions as is seen in Fig. 3.3. The resulting shares of the demand are shown in Tab. 3.1. For the hourly demand profile, Egyptian data from 2011 is used.

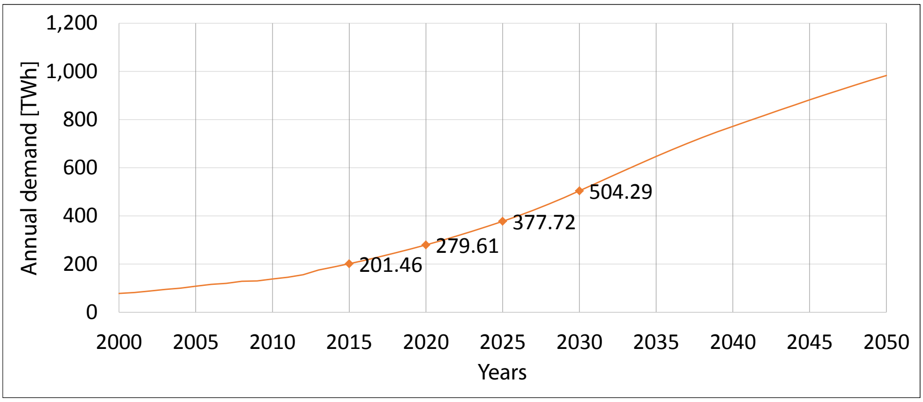


Figure 3.2: Historic and predicted annual demand in Egypt, specific numbers for 2015, 2020, 2025 and 2030

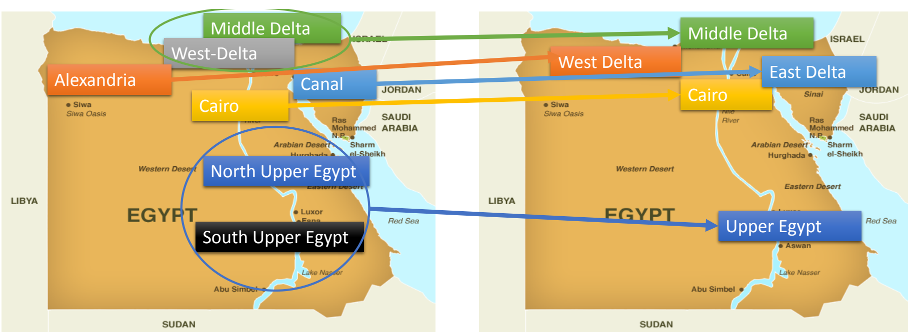


Figure 3.3: Assigning the seven transmission zones to the five Balmorel regions

Table 3.2: Characterizing parameters per fuel-/ turbine type

Fuel/ Turbine type	Efficiency	Fixed O&M costs	Variable O&M costs	Lifetime
	[%]	[$/MW]	[$/MWh]	[years]
Natural gas - CC	59	25	2.1	30
Natural gas - GT	38	20	1.7	30
Natural gas - ST	35	45	3.8	30
Coal	35	45	3.8	30
Nuclear	33	140	0.0	60
Fueloil	given by EEHC	45	3.8	30
Lightoil	given by EEHC	20	1.8	30
Water	based on FLHs	46	3.3	50
Sun	based on FLHs	24	2.0	25
Wind	based on FLHs	22	3.7	20

3.2.3 Generation plants

In the annual EEHC report [5] all existing power plants are listed and categorized by production company. Based on this list the current generation portfolio was set up in the EAPP project. Some characterising parameters such as capacity, efficiency fuel type and type of turbine (gas (GT), steam (ST) or combined cycle (CC)) are also found in [5]. When no plant-specific data was available, the values in Tab. 3.2 were used for efficiency, the operation and maintenance (O&M) costs and the lifetime. The efficiency of the wind and solar and hydro power is based on the full load hours (FLHs) In order to simulate unserved demand, an extra virtual power plant is modelled with a variable cost of 1199 $/MWh (no fuel price). When this plant generates, it would correspond to an outage and the related costs are intended to reflect the black-out costs. For building up the future generation technologies in Balmorel, the expansion plan by the EEHC was used. This plan describes the foreseen power plants for 2013 to 2027 in Appendix A.1.

Web searches helped locate many of these intended plants, as often the initial plans were available on-line. Using Google Earth to visualise the new plants, it was possible to allocate them to the regions used in the model. This can be seen in Fig. 3.4, where the colors indicate the regions. When no other characterizing data was available, data from Tab. 3.2 was used. Two power plants from the EEHC plan were not found and have been allocated to Cairo, as it is the region with highest consumption: Combined cycle plants and Steam units.

Figure 3.4: Future Egyptian power plants, (yellow: Cairo, turquoise: East-Delta, green: Middle-Delta, indigo: Upper Egypt, orange: West-Delta)

3.2.4 Fuel prices

The fuel prices in Egypt have been included in the model during the EAPP project, they are based on the IEA New Policies Scenario that assumes the low carbon agreements of G20 are being implemented. For natural gas, regional price difference exist as NG needs to be transported by gas pipes. The natural gas prices prices were assumed to start at the production price in 2013 and converging to the European price by 2030. The fuel prices are given in Tab. 3.3 for the four simulation years. For natural gas and coal a distribution costs of 0.50 and 1.00 $/GJ respectively are added to these prices.

3.2.5 Transmission

The division in 5 regions forms an increase in complexity, but is by no means a fully accurate representation of the grid, consisting of a great network of transmission lines on different voltage levels. The simplification is introduced that some of the Egyptian regions have one bidirectional transmission cable with a fixed maximum capacity. In reality the amount of electricity that can be trans-

Table 3.3: Fuel costs per fuel type in Egypt

Fuel/	Fuel costs 2015	Fuel costs 2020	Fuel costs 2025	Fuel costs 2030
	[$/GJ]	[$/GJ]	[$/GJ]	[$/GJ]
Natural gas	9.14	10.39	11.63	12.88
Coal	4.04	4.21	4.33	4.37
Nuclear	1.00	1.00	1.00	1.00
Fueloil	18.19	18.58	19.08	19.91
Lightoil	22.37	22.88	23.43	24.39
Water	0.00	0.00	0.00	0.00
Sun	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00

Figure 3.5: Transmission capacities on connections between regions in MW

mitted is highly dependent on the current flows on the grid. The capacity of the transmission lines was again found from the Egyptian transmission company's data where the actual flow on the between the 7 transmission zones is given for high and low demand in 2014 and 2015. The maximum amount of power on a line out of the 4 dataset is taken as the capacity of that connection. As earlier the transmission data needs to be converted from the 7 zone system to the 5 regions. In some cases this means adding the values of the transmission lines. The resulting capacities are shown in Fig. 3.5. The transmission capacities are kept constant in the years 2020, 2025 and 2030.

3.2.6 Unit Commitment

In order to implement proper unit commitment in Balmorel model, it is necessary to characterize the power plants included in the model. The parameters needed for unit commitment modelling are:

Table 3.4: Unit commitment parameters per fuel-/turbine type

Fuel/ Turbine type	**Start-up costs**	**Min gen**	**Fixed fuel use**	**Min down**	**Min up**	**Ramp up**	**Ramp down**
	[$/MW]	[% of total cap]	[% of fuel use at full cap]	[hours]	[hours]	[% of full cap/hour]	[% of full cap/hour]
Natural gas - CC	194.1	0.46	0.20	3.15	2.63	2.63	1.97
Natural gas - GT	97.9	0.34	0.17	0.64	0.62	7.33	8.07
Natural gas - ST	210.7	0.14	0.08	4.0	3.5	0.9	0.9
Coal		353.60.37	0.1	5.0	3.2	0.8	1.2
Nuclear	530.3	0.5	0	0	0	1.2	1.2
Fueloil	205	0.32	0.08	4.0	2.2	0.7	0.9
Lightoil	61.6	0.23	0.19	0	0	9.1	12.1
Water	0	0.38	0	0	0	14.6	37.7

- **Start-up costs**: given in $ per MW of installed capacity
- **Minimum generation**: as a share of the total capacity
- **Minimum up and down time**: in hours
- **Ramp-up and -down time**: share of the total capacity that can be started-up/shut-down in one hour
- **Fixed fuel use**: given as share of the fuel used at full capacity, changes the efficiency to a new marginal efficiency (see also Fig. 2.2)

These data are given for each generation facility. As the unit commitment parameters for most renewable production are negligible, only the plants running on natural gas, coal, fuel oil and light oil and nuclear are modelled with UC. The biggest hydro power generator is also subject to a minimum generation limit. Due to a lack of data for the actual plants, the parameters are found from official data for the Irish power plants [26]. Ireland was used as refence country as it had the most comprehensive data set in terms of unit commitment data. The average was found per fuel type or turbine type for each of the parameters. As Ireland has no nuclear generation, these values are found from Swedish data. The resulting values are given in Tab. 3.4 The assumptions in these data are that the generation facilities in Egypt have similar characteristics as in Ireland and Sweden. It is likely that for the newly built power plants this assumption holds relatively well as the power plant markets are becoming more international and uniform. For the older Egyptian plants some deviations from the Irish or Swedish values will probably exist. Another simplification is that all power plants from one subgroup are considered to have the exact same UC values, while from inspecting the Irish data it is clear that there is quite some variations within the used categories.

3.2.7 Hydropower

The hydro power in Egypt is a substantial part of the energy mix. A few smaller power plants are modelled as run-of-river, while the biggest "Aswan High Dam" is has a reservoir. The reservoir hydro plant is described by the the weekly water inflow in the reservoir. This is determined by the yearly variations of the Nile current and based on information given by EEHC. Before any more detailed simulations are made, a simulation over the whole year (52 weeks) is done in which the amount of water used per week is optimized and saved. This is done without UC. When later weekly simulations are performed for individual weeks, the weekly amounts of generation are taken from the yearly run. The maximum load of the High Aswan Dam is found in [5] and is 2300 MW. The minimum daily generation can also be found and amounts to only 12% of its maximum daily generation. The hourly minimum generation is then set to 10% in the UC parameters (adding some hourly fluctuation to this daily minimum), in order not to stop the current in the Nile river. For the run-of-river plants, the generation profile is fixed and is not optimized by Balmorel. This is a simplification of reality as the production of these hydro plants is highly related to the Aswan dam's generation profile. As the run-of-river plants are relatively small in capacity, not modelling them accurately is not expected to be a big limitation of the model.

3.2.8 Windpower

As explained before, there are two regions in Egypt in which power is generated by wind. The wind profile used is that of Karoo in South Africa but normalized to fit the average yearly full load hours of Egypt (2276), there is no differentiation for the two regions in wind power. As seen from section 1.5, this is not conform to reality. More data on the FLH and different wind profiles for both regions could make a big difference to the variables in the simulation. Presumably the FLH for the individual wind farm locations are much higher compared to Egypt's average value as the most optimal wind sites are used first.

3.2.9 Investments

When Balmorel performs an investment optimization, the simulation runs the full 52 weeks, with aggregated time-steps and no unit commitment parameters. Investments will only be allowed from the year 2020. The model is capable of investing both in generation capacity and in transmission capacity. For in-

Table 3.5: Technology catalogue for investments

Technology	CAPEX [m$/MW]	Fixed O& M [k$/MW]	Variable O& M [$/MWh]	Efficiency [%]	Lifetime [years]
Steam coal - subcritical	1.8	45	3.8	35	30
Steam coal - supercritical	2.2	63	5.3	40	30
CCGT	0.8	25	2.1	59	30
Gas Turbine	0.4	20	1.7	38	30
Medium speed diesel	1.6	22	1.8	45	30
Low speed diesel	2.4	10	0.8	46	30
Nuclear	5.7	140	0.0	33	60
Solar PV	1.9	24	2.0	FLHs	25
Onshore wind	1.5	22	3.7	FLHs	20

Table 3.6: Transmission line costs investments

Transmission line	Costs [k$/MW]
Cairo - East Delta	86
Cairo - Middle Delta	63
Cairo - Upper Egypt	133
East Delta - Middle Delta	109
East Delta - Upper Egypt	156
Middle Delta - Upper Egypt	225
Middle Delta - West Delta	86

vesting in generation Balmorel can choose generation units from the technology catalogue shown in Tab. 3.5. The data given on the plant's efficiency and costs are found from the IEA energy outlook [27]. The investment policy is that 110% of peak load needs to be available in thermal capacity. For the investments in transmission capacity, the maximum increase in capacity is 4000 MW every 5 years on all existing lines. The specifics are shown in Tab. 3.6 and based on their length and the EAPP data report, for lines of 500 kV. Balmorel invests in capacity when the annualized investments costs are less than the decrease in operating costs.

3.3 Scenario simulations

In the scenario simulations 5 possible variations of the electricity future of Egypt are modelled, which are summarized in Tab. 3.7 These potential future scenarios are simulated for 5 weeks (week 1, 11, 21, 31, 41) and in four years: 2015, 2020, 2025 and 2030. The hydro power generation is modelled as described in 3.2.7.

Table 3.7: Scenario summary

	EEHC gen. <2020	EEHC gen. >2020	Invest. in trans.	Invest. in gen.	Policy
Main	x	x			
Main+Trans	x	x	x		
Main+Invest	x	x	x	x	
Investment	x		x	x	
Renewable	x		x	x	Renew. shares

3.3.1 Main scenario

In the main scenario, Balmorel simulates the electricity system with the future generation capacity as forseen by the EEHC expansion plan and as described in section 3.2.3, the transmission lines are as described in section 3.2.5. This scenario is relies on the lowest amount of assumptions and is therefore named the Main scenario. The simulations are run twice for this scenario, once with and once without unit commitment constraints activated.

3.3.2 Main+Trans scenario

The Main scenario has fixed transmission capacities over the years, as there is no information available on possible expansions of the grid. However, it is likely that the transmission lines are not sufficient for the rising demand and generation. In the Main+Trans scenario, the same inputs are used as in the Main scenario, whilst allowing the model to invest in extra transmission capacity.

3.3.3 Main+Invest scenario

Another shortcoming of the Main scenario simulation is that the EEHC expansion plan only provides information on new capacity until 2027. As the simulations include the year 2030, the 2027 generation units are not meant to be carry the demand of the last simulated year. Therefore a simulation is made where the model gets to invest in both generation units and transmission increase.

3.3.4 Investment scenario

Even though the EEHC has a clear plan when it comes to the expansion of the generation mix of Egypt, it is interesting to examine what the electricity landscape would become when the generation is determined by Balmorel's investment optimization. In the Investment scenario therefore, all new generation from the EEHC plan from 2020 and onwards is removed from the input and is replaced by the generation the model decides to invest in. The model is also allowed to invest in transmission capacity.

3.3.5 Renewable scenario

The Renewable scenario is very similar to the Investment scenario, but adding an extra investment policy that in 2020, 20% of the generation needs to be renewable. This is conform with the NREA plans for renewable energy. In 2025 this value rises to 25% and 30% in 2030.

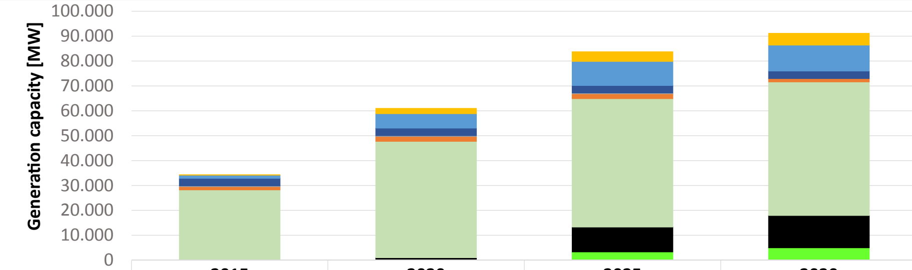
Chapter 4

Results

In this chapter of the thesis the Balmorel results of the different scenarios are discussed. First, the Main scenario is examined in more detail and the difference between simulation runs with and without unit commitment are described. In a second section, the results for the five different scenarios are described and compared to each other in terms of investments, system costs and generations per fuel.

4.1 Main Scenario

The Main scenario is considered the most likely based on information given by the EEHC. No investments are performed in this scenario not in generation capacity nor in transmission lines. The transmission capacities remain constant over the years. In the first paragraph of this section, some key results of the Main scenario are shown, where they UC constraints are included in the simulations. The next paragraphs presents further model outputs that are both showing the characteristics of the scenario as well as being used for comparing the case with and without including UC parameters.



	2015	2020	2025	2030
Sun	175	2.140	3.890	4.740
Wind	1.296	5.806	9.656	10.410
Water	3.000	3.032	3.032	3.032
Lightoil	321	321	321	
Fueloil	1.324	1.974	1.974	1.350
Nat. Gas.	28.209	46.724	51.562	53.662
Coal		1.000	10.000	13.000
Nuclear			3.300	4.950

Figure 4.1: Generation capacity in the Main scenario for 2015, 2020, 2025 and 2030

4.1.1 Generation capacity, production and demand

The total generation mix is used as input data and entered in the model exogenously as shown in Fig. 4.1. The wind power capacity is planned to increase with 7050 MW in addition to the already committed wind farms (2015-2018), resulting in a total increase of about 9000 MW i.e. 800% from 2015 to 2027. The 7050 MW wind power planned in the timespan 2019-2027 is a commitment made by the EEHC and NREA to increase wind power generation as explained in the introduction. Apart from wind power, the main increase in the expansion plan is natural gas that continues to dominate the power system in Egypt. In 2020, some coal generation appears, which is further increased in following years. From 2023, nuclear capacity is introduced in the energy mix, with a rise in up until 2027. Solar power capacity is planned to grow rapidly but remains under 5000 MW in 2027. In Fig. 4.2 the relative increase in demand and capacity is shown, where the year 2015 is chosen as reference year. The expansion in capacity is steeper compared to the demand increase and the power system therefore has higher security of supply (also seen from values of unserved demand) in the years 2020 and 2025 than in 2015. When higher shares of renewables are integrated in the energy system, it is necessary to have enough thermal capacity to cover periods when no wind is available and it is therefore sensible to have higher total capacity (including thermal and fluctuating power). In the year 2030 however, the gap between the demand and capacity increase is reduced

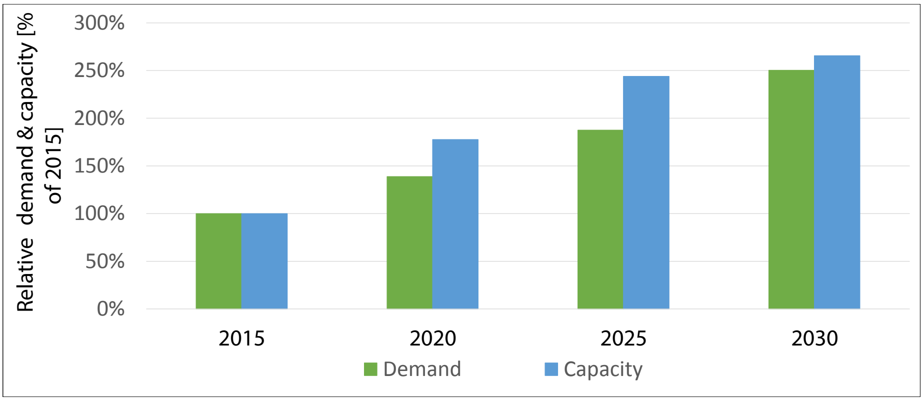
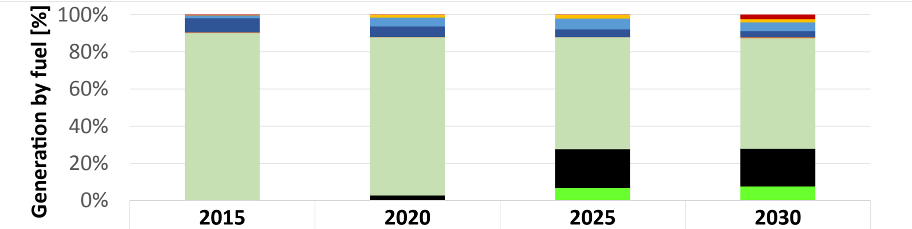


Figure 4.2: Relative demand and capacity increase in the Main scenario for 2015 (base year), 2020, 2025 and 2030 - with UC

and the system, containing a big amount of non-dispatchable renewable power is unable to cover the demand at all times. This is illustrated in Fig. 4.3 where the relative generation share by fuel is depicted. In 2020 and 2025 there is a drop in unserved demand (to values of 0.005% 0.012% respectively); the unserved demand, rises drastically in 2030 to 2.2%. The reason for this failure to meet the demand is that the EEHC plan is only projecting capacity expansion up until 2027 and no additional units were added after this year. It is obvious that the Egyptian energy system will further expand between 2027 and 2030 in order to satisfy the increasing electricity load. Apart from the unserved demand, Fig. 4.3 also served to show the shares of fuel use. When looking at 2020, the shares for hydro and solar power are approximating the expected values based on the 2020 Renewable Energy Development Program. 1.4.1 (6% and 2% hydro and solar generation respectively), but the share of wind generation is much lower than intended for 2020 (12%). The reason for this could be an underestimated full load hours for the wind power generation and solar energy, where country averages were used and that were not adapted to the different wind farm locations. In section 1.4.2, it is shown that the regions in the Gulf of Suez are especially high in wind potential. In this Main scenario, no curtailment occurs and therefore the low share of wind power is not caused by the energy mix. Natural gas generation is losing ground to coal and nuclear that for a big part take over the base load generation in progressing years.

The power generation in the four years for the individual regions in Egypt are illustrated in Fig. 4.4. To evaluate the values of power generation, the demand is shown as well. The regional share of the total demand is kept constant over the years. The production share however, does not increase with the same ratio and depends on where expansions in the capacity are located. The difference between



	2015	2020	2025	2030
Unserved	0,1%	0,0%	0,0%	2,2%
Sun	0,2%	1,4%	1,9%	1,7%
Wind	1,5%	4,7%	5,8%	4,7%
Water	7,6%	5,7%	4,1%	3,3%
Lightoil	0,1%	0,0%	0,0%	0,0%
Fueloil	0,3%	0,1%	0,1%	0,5%
Nat. Gas.	90,3%	85,2%	60,3%	59,5%
Coal	0,0%	2,8%	20,8%	20,2%
Nuclear	0,0%	0,0%	6,9%	7,8%

Figure 4.3: Fuel share in generation in the Main scenario for 2015, 2025, 2025 and 2030 - with UC

the demand and production in each region is an indication of the requirements for the transmission system. The demand is highest in Cairo followed by Middle Delta. These loads cannot be met by the regional production. The electricity therefore needs to be imported from regions East Delta, West Delta and Upper Egypt. In 2020, a large increase in capacity (3 new natural gas units) in Middle Delta, make the region self-sufficient in that year, but the increase in capacity is not sufficient to cover the demand in later years. Upper Egypt starts out as an import region, but the high increase in wind, solar and natural gas capacity (and even a small amount of hydro power) transforms it to an export region starting from year 2020.

4.1.2 Full load hours, system costs and electricity price - with and without unit commitment

In the following section the results shown have both an indicative value for the Egyptian energy system as it is laid out to develop, and a verification function on the added benefit and increase in accuracy of implementing unit commitment constraints.

As an illustration of the difference between the generation profile with and without UC Fig. 4.5. A week in 2020 is shown in both cases. A decrease in

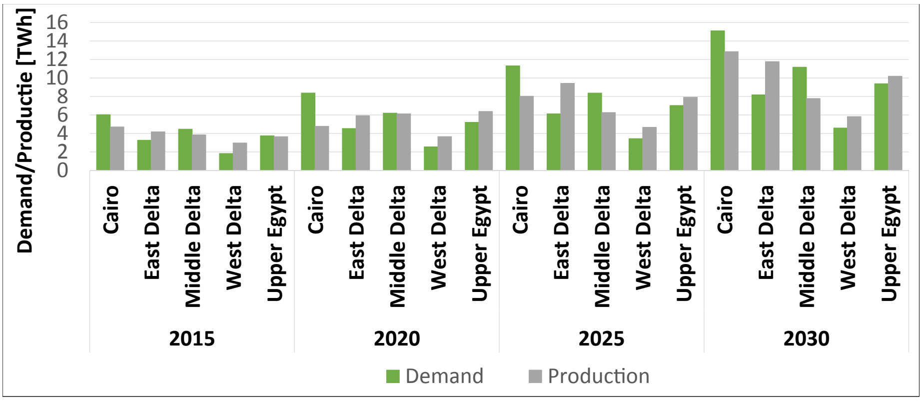


Figure 4.4: Demand and production per region in the Main scenario for 2015, 2020, 2025 and 2030 - with UC

flexibility of the units is seen when adding UC. The units stay on longer (due to start-up costs and minimum on-time) and produce preferably at maximum capacity (because of fixed fuel use, that has the highest impact at low generation shares). It can also be seen that some units stay on-line at minimum generation level in order not to pay start-up costs after a shut down. In this week less power is generated in the UC case, meaning that generators in different regions produce more.

Full load hours: In Fig. 4.6 the full load hours per fuel-/technology type are shown for the years that they have installed capacity in Egypt. They show a general decrease with the years, except 2030, where the shortage of generation capacity forces existing plants to run more hours. The downward trend is due to a higher ratio of capacity over demand. The jump in generation in 2020 for "Nat. Gas - GT" (natural gas, gas turbine) is seen to disturb this trend, but can be explained by a large capacity expansion of one of the three GT units. With respect to the UC simulations a shift can be seen from production from "Nat. Gas - GT" plants and "Nat. Gas - CC" (combined cycle natural gas plants) plants to the "Nat. Gas - ST" (natural gas, steam turbine), fueloil and lightoil power plants, that have higher marginal costs but also higher start-up costs and are therefore shut down less often compared to the no UC case.

System costs: When looking at the system costs in Fig. 4.7, the trend in the years 2015, 2020 and 2025 in both cases is a gradual increase in fixed and fuel costs. The variable costs are explained both examining the amounts of unserved demand (with very high variable costs) and by noting that the variable cost of

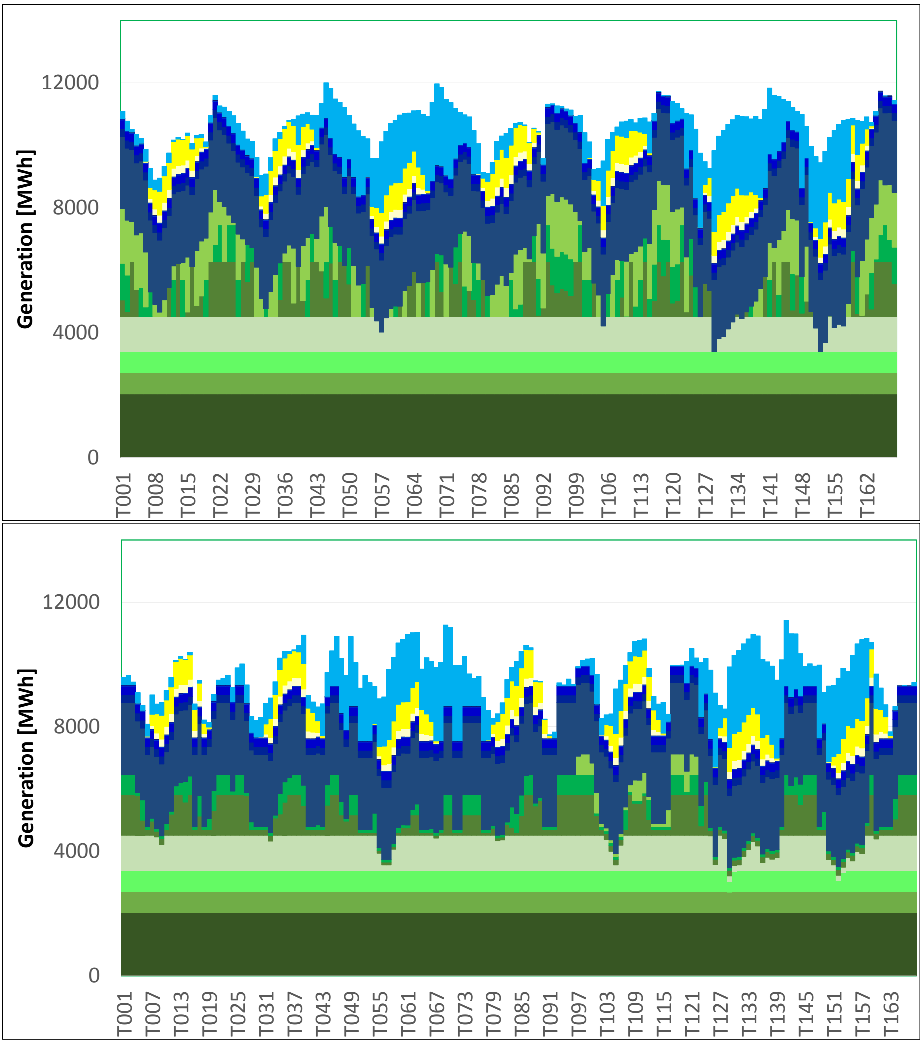
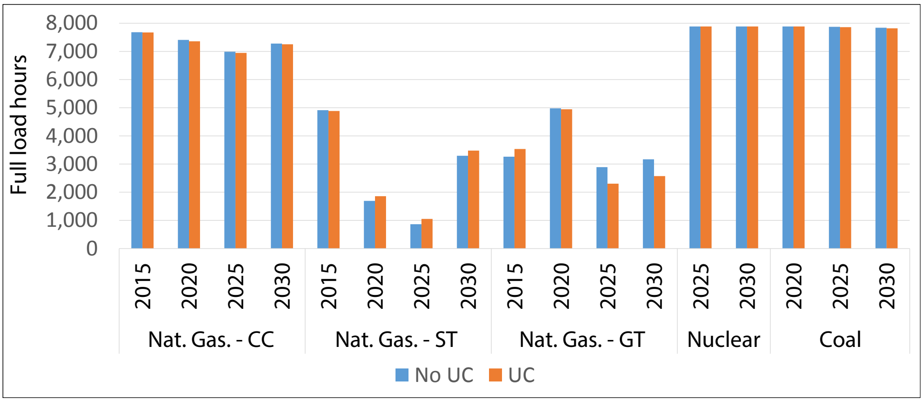
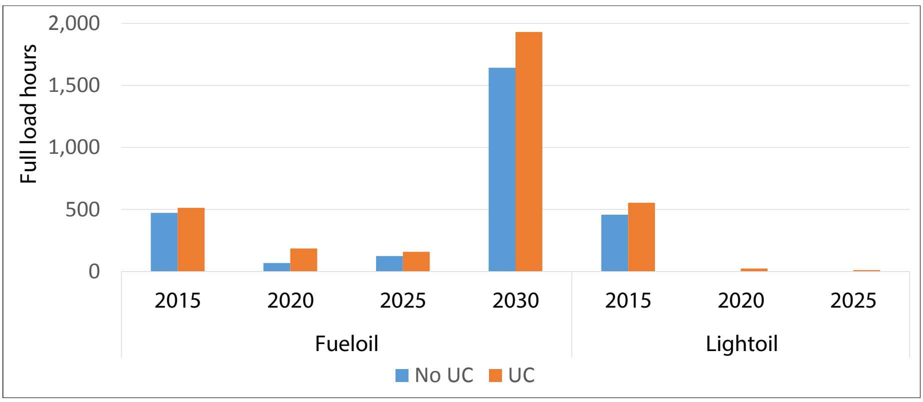


Figure 4.5: Generation in week 21 2020 - with and without UC

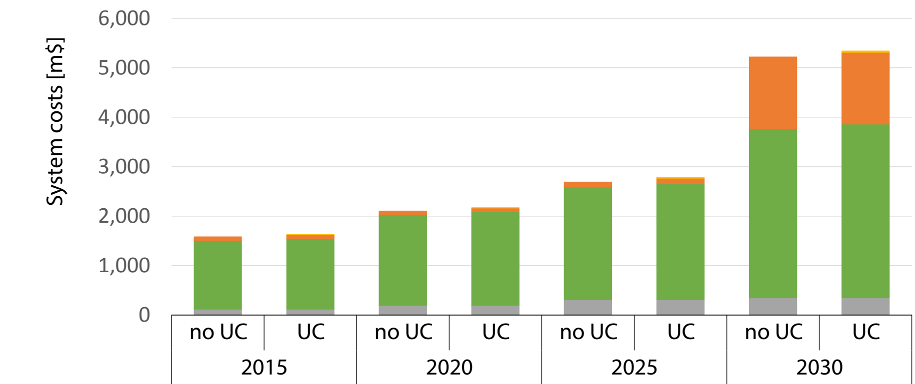


(a) Natural gas, nuclear and coal



(b) Fueloil and lightoil

Figure 4.6: Full load hours in the Main scenario for 2015, 2020, 2025 and 2030 - with and without UC



	no UC 2015	UC 2015	no UC 2020	UC 2020	no UC 2025	UC 2025	no UC 2030	UC 2030
Start-up costs	0.00	8.96	0.00	7.20	0.00	23.65	0.00	29.02
Variable costs	80.51	81.14	69.80	70.25	104.05	104.98	1448.10	1449.64
Fuel costs	1384.07	1422.27	1837.92	1897.43	2278.65	2352.35	3422.72	3512.77
Fixed costs	117.75	117.75	195.00	195.00	307.83	307.83	348.00	348.00

Figure 4.7: System costs in the Main scenario for 2015, 2025, 2025 and 2030 - with and without UC

coal plants compared to natural gas is higher. In 2030 a big jump is seen in in the fuel and variable costs. The inadequate generation system results in higher use of more plants with more expensive fuel or variable costs as well as a higher amount of unserved demand. Examining the effect of a simulation with UC compared to the no UC case, fuel costs exhibit an incline of 2.5 to 3 %; variable costs increase with 0.7 - 0.9 % in all years but 2030, where this increase in only 0.1 %, but should be discarded due to the incomplete energy mix. The higher fuel and variable costs are a consequence of the unit commitment constraints where it is often more advantageous to e.g. run units with higher marginal costs compared to switching to lower cost plants but paying start-up costs or run units at low levels and pay a high costs for fixed fuel use. Taking also the start-up costs in account, the total system costs show an increase of about 2.26 - 3.52% in 2015, 2020 and 2025.

Electricity price: While the differences in total system costs are small but significant, the impacts of the yearly average electricity price is higher, as it is based on the marginal cost of electricity production and not on overall costs, which is seen in Fig. 4.8. As it was shown that 2030 is not a relevant year to examine it is omitted here. For simulations with UC, the trend is a decrease in electricity price; a decline of 25% from 2015 to 2020 and another drop of 9% in the last five years. This is due to the large amount of (cheap) capacity available to provide the demand. The difference between simulations with and without

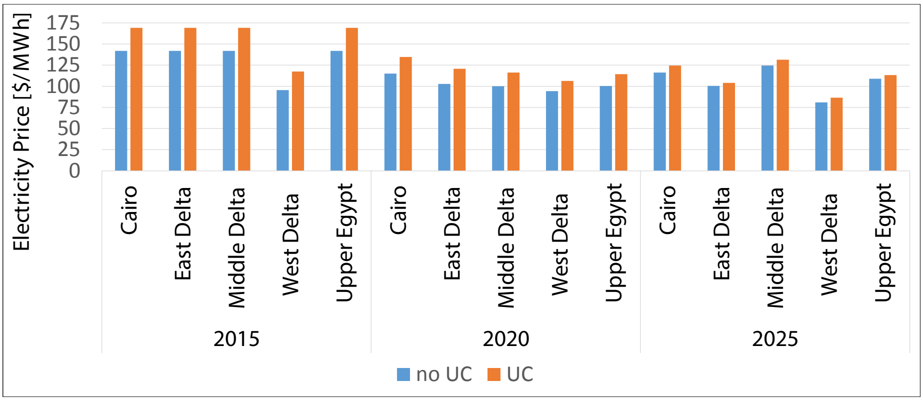


Figure 4.8: Electricity price per region in the Main scenario for 2015, 2020 and 2025 - with and without UC

UC decrease over the years (from 20% to 16% and 5% in 2015, 2020 and 2025 respectively), due to the increase in coal and nuclear generation that are less effected by UC constraints as they function as base load without shut-downs or minimum generation issues.

4.2 Comparison of different scenarios

This section describes the results for the scenarios explained in section 3.3 in terms of investments, generation and system costs. The CO_2 emissions and the electricity price will also be looked at.

4.2.1 Investments

The first interesting results are related to the investment runs, in which generation and transmission capacity are optimized for each scenario by the Balmorel model. In Fig. 4.9 the generation capacity is shown for four scenarios:

- **Main scenario**
- **Main+Invest scenario**: the main scenario is optimised by model-based investments in both generation and transmission capacity

- **Investment scenario**: planned expansion from 2020 is removed as input data and replaced by endogenous investments in both generation and transmission capacity
- **Renewable**: similar to Investment scenario, but with an added policy of 20%, 25% and 30% renewable generation in 2020, 2025 and 2030 respectively

The Main+Trans scenario is omitted as no investments in generators are done. The capacity composition is therefore equal to that of the Main scenario. For the Main+Invest scenario, the exogenous capacity, that is equal to the capacity in the main scenario, is shown as "Exo: Main", so it is clear which are the endogenous investments (note that endogenous investments are exogenously added to later years, these are not included in "Exo: Main"). It is remarkable that in the Main+Invest scenario already in 2020 some extra investments in natural gas plants are made, despite the energy system functioning well in the Main scenario, but that will have lower total costs as a results (see later). In 2030 an extra investment is made to fix the gap between the generation capacity of 2027 and the demand of 2030 in the Main scenario.
For the Investment and Renewable scenario scenarios the exogenous capacity, which is the capacity that is already built or planned in the years up to 2019, is shown as "exo: <2020". In the Investment scenario only in natural gas is added to the energy mix in the years 2020 and 2025, but in 2030 coal is chosen as to expand the capacity, because of the steeper increase in fuel price of natural gas in 2030. The Renewable scenario also invests in natural gas in 2020 and 2025, but adds about 13 GW and five GW of wind power in each year respectively (mainly in East Delta), which brings its total wind power capacity in 2020 to more than double that of the Main scenario. The NREA goal of 20% in 2020 is thus not reached in the Main scenario but needs double the wind power capacity to be achieved in the Renewable scenario. In 2030 the accumulative investments in wind power are 26.5 GW. The rest of the 2030 investments are coal.

There are four scenarios in which investments in transmission capacity by the model are allowed. However, in the scenarios Investment and Renewable, the model chooses to locate the new investments in the areas where the demand is higher and in this way limiting the need for increased transmission capacity between the regions. For the scenarios Main+Trans and Main+Invest, the increase in capacity is shown in Fig. 4.10 and is bidirectional. Mainly the connection Cairo to East Delta, Cairo to Middle Delta, and Middle Delta to West Delta are expanded. These expansions are designed to get the extra generation that can be produced in the 3 Delta regions to Cairo, with the highest demand. In the Main+Invest scenario, the increase in transmission is less extensive because the extra generation is placed in the appropriate regions, namely Cairo and East Delta get the highest investments in new capacity in 2020. Middle

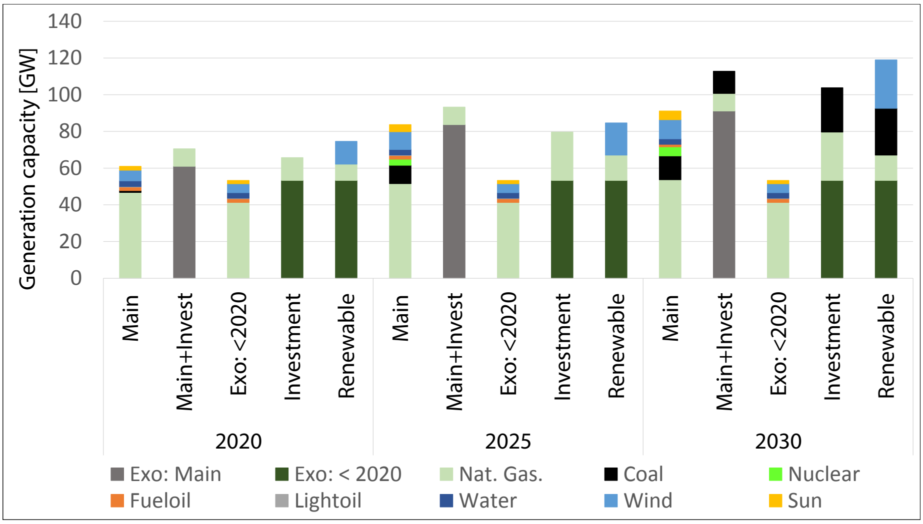


Figure 4.9: Generation capacity in four relevant scenarios in the years 2020, 2025 and 2030

Delta is the region that will have the highest share of the coal investments in 2030. One can notice that the increase in transmission capacity occurs in the year without generation investments. The early investment in generation, thus makes transmission grid expansion unnecessary in 2025.

4.2.2 Generation

For the generation in the five scenarios Fig. 4.11 shows the relative generation by fuel for the years 2020, 2025 and 2030. In 2020 and 2025, the difference between the Main scenario and the Main+Trans or Main+Invest scenario are very small: a tiny increase in natural gas generation at the cost of fueloil, lightoil and hydro power. Compared to the Main scenario, the Investment and Renewable scenarios show an increase in natural gas in 2025, which is due to the high amount of natural gas capacity. The Renewable scenario shows about 14%, 24% and 27.5% wind generation in 2020, 2025 and 2030 respectively. It is the only scenario where wind curtailment occurs, but with values below 0.06%.

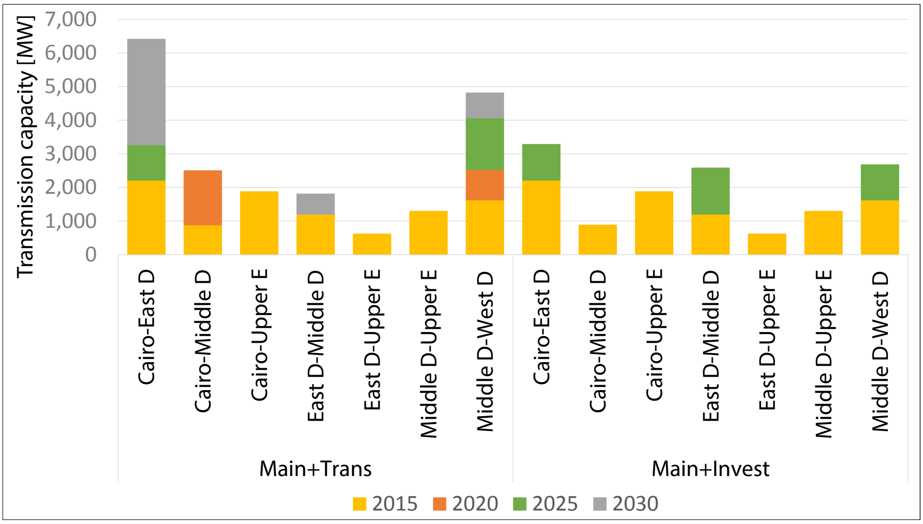


Figure 4.10: Transmission capacity in two relevant scenarios for the years 2015, 2020, 2025 and 2030

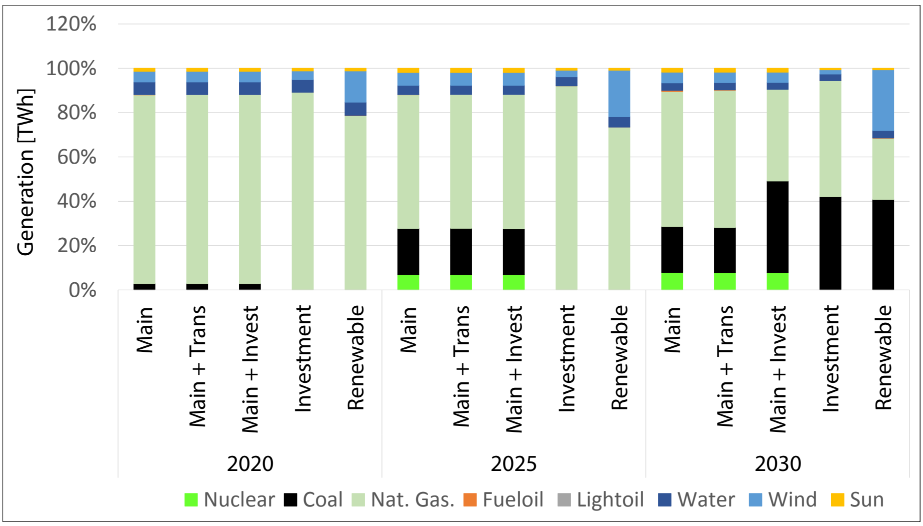


Figure 4.11: Relative generation in the five scenarios for the years 2020, 2025 and 2030 - with UC

4.2.3 System costs

Fig. 4.12 shows the costs in the five scenarios. Both the fixed costs and the annualized investment costs are scaled to the five weeks in the simulation. It is important to note that in terms of investments costs the Main, Main+trans and Main+Invest scenarios are not comparable to the Investment and Renewable scenario since the exogenous investments (used as input and not optimized by the model) do not have investment costs associated to them. In all three years, the cheapest scenario is the Main+Invest scenario. A conclusion that can be drawn from this is that the EEHC expansion plan does not bring down the operation costs to its optimal level, which can be done by adding some capacities.

The Investment scenario represents the optimal balance between capital costs and operating costs (fuel, fixed, variable and start-up costs). These operating costs are lower in the Investment scenario than the Main scenario in 2020 and 2030, but higher in 2025. This indicates that in the Main scenario, the system has does not have sufficient or appropriate generation to have low operating costs and in 2025 the generation mix is over-dimensioned and thus high in capital costs (exogenous and thus not shown in the figure). It can be noted that in 2020, the simulations with generation investments (Investment and Renewable), manage to bring the system costs down even when their investment costs are included in the comparison while this is not the case for the Main scenario. When comparing Investment and Renewable scenario, it is seen that the total costs for the latter are slightly higher (3% in 2030) but the operating costs are much lower due to lower fuel costs of renewables. It is interesting to not that the difference between the total costs of the Investment and Renewable scenario is only 1.5% in simulations without curtailment (not shown in the figure).

4.2.4 CO_2 emissions

Apart from 2030, the CO_2 emissions go down in the scenarios with investments, Main+Invest, Investments and Renewable. Less coal is used in as investments in natural gas are made. The Renewable scenario has significantly less emission compared to the Investment scenario. In 2025 a drop of 19% is seen. This difference decreases in 2030 as the Renewable scenario starts using coal.

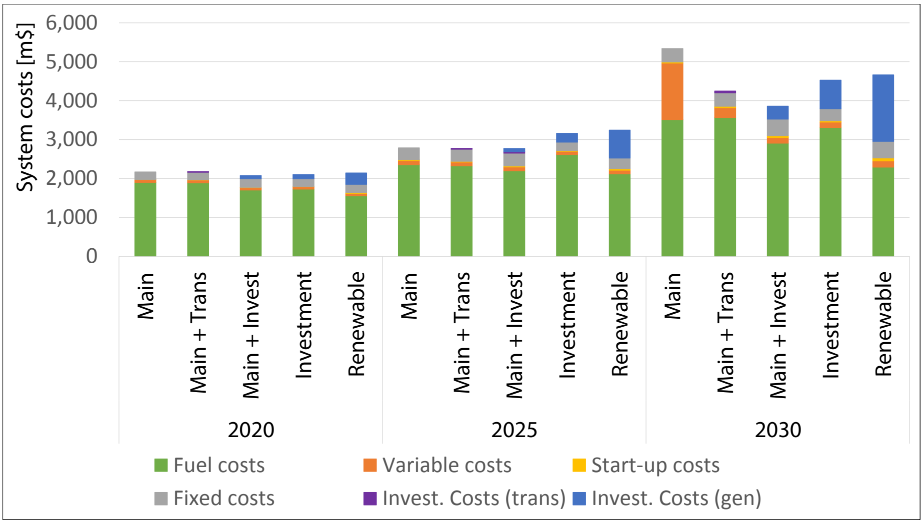


Figure 4.12: System costs in the five scenarios for the years 2015, 2020 and 2030 - with UC

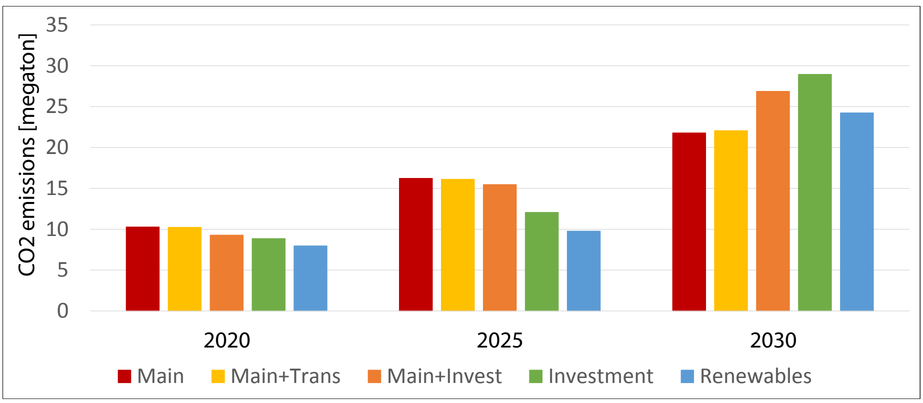


Figure 4.13: CO_2 emissions in the five scenarios for the years 2015, 2020 and 2030 - with UC

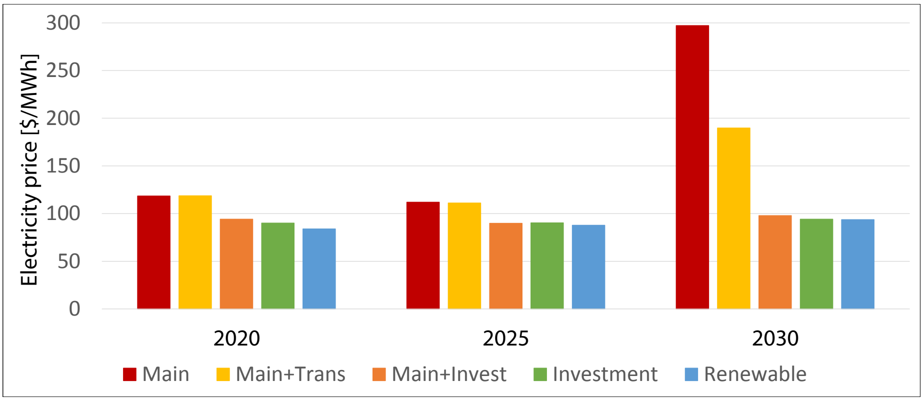


Figure 4.14: Electricity price in the five scenarios for the years 2015, 2020 and 2030 - with UC

4.2.5 Electricity price

In the electricity prices a clear drop is seen when endogenenous investments are made. The Renewables electricity price is slightly lower than the Investments price due to the low marginal costs of wind that have an impact on the average price.

Chapter 5

Validation of results

5.1 Set-up of sensitivity analyses

As the input data used in the simulations is subject to unavoidable uncertainty, a sensitivity analysis is conducted for some of these parameters to see the impact of deviations in these data. Since the topic of the thesis is the analysis of the impacts of wind capacity on the unit commitment, it is interesting to investigate the effects of increasing or decreasing the wind capacity in the Egyptian electricity system and comparing the difference with and without UC. The transmission grid is an input parameters with high uncertainty, as the data is based on snapshots in 2014 and 2015 and no information is found for the expansion of the grid. In order to see the effects of more limited grid or a capacity expansion, a sensitivity analysis will be performed on this parameters as well. The effect of deviations in UC parameters is also relevant, since the values used in the scenarios are based on rough averaging of data in other nations and the behaviour of the unit commitment in the presence of high shares of wind power a main research question of this thesis. Finally, as explained in section 2.4.3 it is possible to set an allowed error on the objective function. Depending on the errors of the variables of interest, a compromise between accuracy and simulation time can be obtained through a sensitivity analysis of this error.
For the sensitivity simulations, the Main scenario, year 2025 (when there is both lightoil, coal and nuclear capacity), are used as a starting point. The same five

weeks as in the Main scenario (1, 11, 21, 31 and 41) are chosen for all sensitivity analyses except the accuracy investigation where only week 11 was ran to avoid too long calculation times. In each sensitivity test one single input parameter is varied:

- **Wind capacity**: From 0% to 400% of Main scenario (9656 MW)
- **Transmission**: From 0% to 250% of Main scenario (see 3.5, all transmission lines are varied with the same ratio)
- **Start-up costs**: From 0% to 250% of Main scenario (see 3.4, values of all fuels/technologies are varied with the same ratio)
- **Fixed fuel use**: From 0% to 250% of Main scenario (see 3.4, values of all fuels/technologies are varied with the same ratio)
- **Minimum generation**: From 0% to 250% of Main scenario (see 3.4, values of all fuels/technologies are varied with the same ratio)
- **Accuracy**: From 1 m$ to 0.05 m$ allowed error in objective function

5.1.1 Wind capacity

When considering wind integration, a relevant variable is the wind curtailment. A high degree of wind curtailment is a signal of improper wind power integration. The relative wind curtailment versus wind capacity (% of the wind capacity in the Main scenario) is seen in figure 5.1a, which is calculated in Eq. 5.1; c_{rel} is the relative curtailment, w_{curt} and w_{no_curt} are the wind generation with and without curtailment.

$$c_{rel} = 1 - \frac{w_{curt}}{w_{no\_curt}}[\%] \tag{5.1}$$

Curtailment is found for simulations with and without UC. The difference between the two percentages in percentage point [pp], c_{diff} (Eq. 5.2), is shown on the right axis.

$$c_{diff} = c_{rel,UC} - c_{rel,noUC}[pp] \tag{5.2}$$

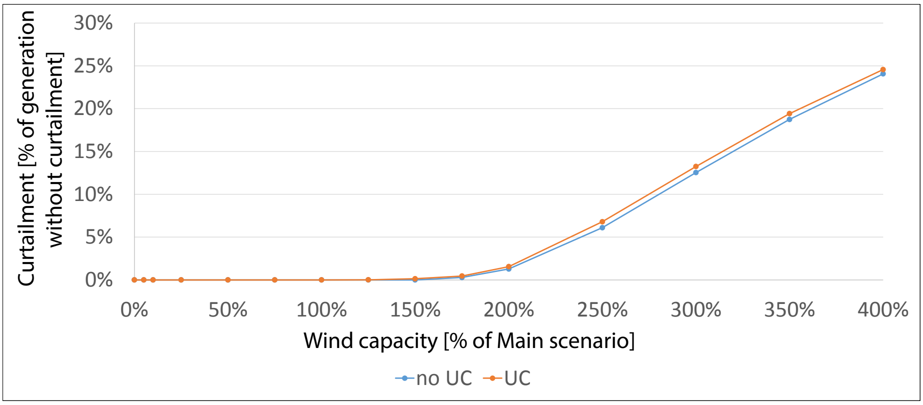
Starting from 125% of the intended wind capacity, small levels of curtailment are seen for the UC case. The curtailment grows exponentially with installed wind capacity to about 25% at 4 times the planned wind capacity. The difference between no UC and UC is interesting as it gives an indication of the amount of curtailment that is due to UC constraints as opposed to transmission limitations. As curtailment with UC starts earlier compared to without UC (at 175% of planned wind power), the initial curtailment is UC-related, more specifically the minimum generation and start-up cost constraint causes the curtailment.

The value of wind (VOW), which is calculated by in Eq. 5.3 as $Pvow$, where h is the hour and H the number of hours; r the region and R the number of regions in the simulation. $w_{h,r}$ signifies the hourly wind generation in region r and $p_{h,r}$ the hourly electricity price. The VOW can be regarded as an average electricity price for wind generation, when taking into account the hours for which wind power is actually available. The higher the value of wind the more profitable for wind farm operators. The VOW is usually lower than the electricity price.

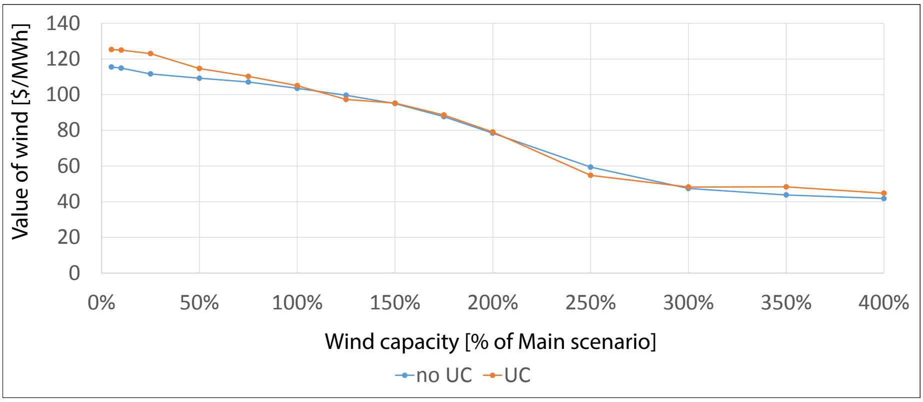
$$p_{vow} = \frac{\sum_{h=1}^{H} \sum_{r=1}^{R} (w_{h,r} \cdot p_{h,r})}{\sum_{h=1}^{H} w_{h,r}} \tag{5.3}$$

The value of wind initially stays constant when the wind capacity is low. When the wind integration is minimal, wind power producers are price takers as the wind generation does not yet have a significant effect on the electricity price. As the price is determined in larger shares by thermal generation initially, UC has a significant effect, later on large amounts of wind lower the price and the wind power price is less affected by UC. When the amounts of wind increase to higher values, the merit order effect ensures that wind power generators with low marginal costs have first priority in the market clearing with the consequential decreasing in electricity prices. As a comparison the electricity price is shown in Fig. 5.1c, which is much higher than the VOW.

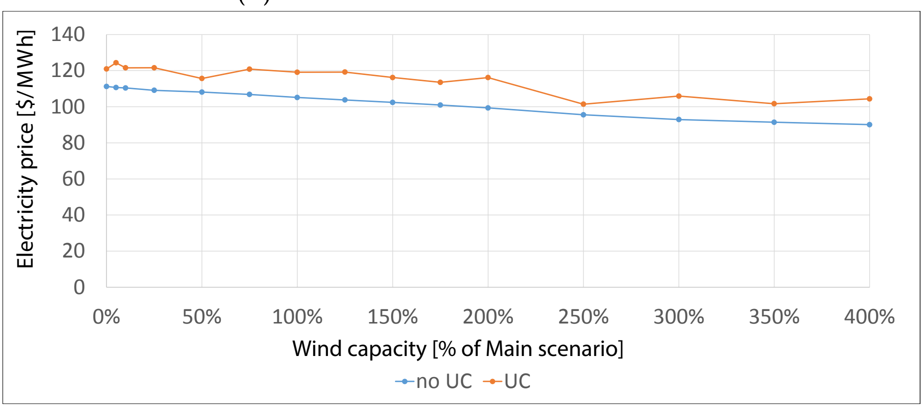
In Fig. 5.2 the full load hours of the different fuel- /plant types are shown. The nuclear power plant is not affected by an increase in wind capacity and runs the maximum FLHs allowed by the simulation (taking maintenance and breakdowns into account). For coal and natural gas the full load hours decrease as their production is replaced by wind generation. A drop is also seen in the flexible lightoil and fueloil full load hours, though from 100% onwards the full load hours are stable, illustrating that peak load will be needed even at high wind shares to help out at peak demands with low wind speeds. As hydro power and solar energy are predetermined by the they are not affected by increased wind generation and therefore not shown.
Finally, the evolution of the system costs is shown in Fig. 5.3a. The main trends are a big decrease in fuel costs, due to wind power replacing expensive fuel-use, slightly higher fixed costs from the extra turbines and an increase in start-up costs. The overall system cost decreases drastically. In the system costs the investment costs for the turbines are not taken into account. From 5.3b a decrease in total costs of about 6% is seen when doubling the wind capacity. Even though the contribution of the start-up costs to the total system costs seems small, it should be noted that doubling the wind capacity adds almost 50% to the start-up costs, implying that thermal generators are less likely to generate on a constant base load and the flexibility requirements are increasing. Fig 5.3c illustrates the total system costs in case of with and without UC. The relative increase of the UC case in compared to the no UC case is also



(a) Curtailment of wind - with and without UC

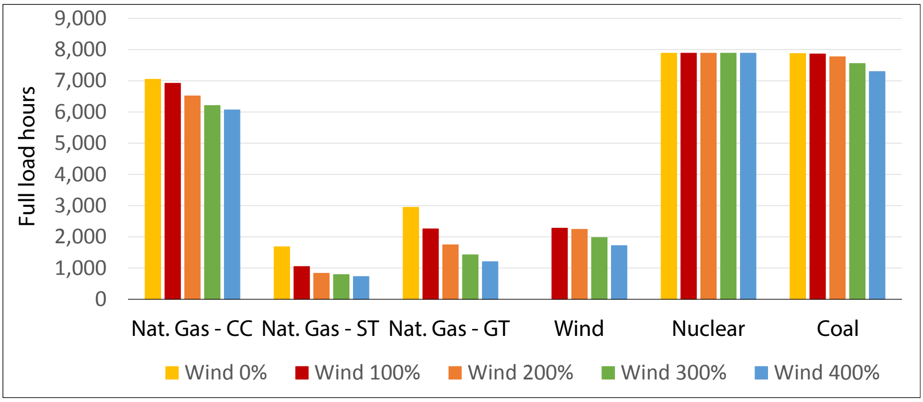


(b) Value of wind - with and without UC

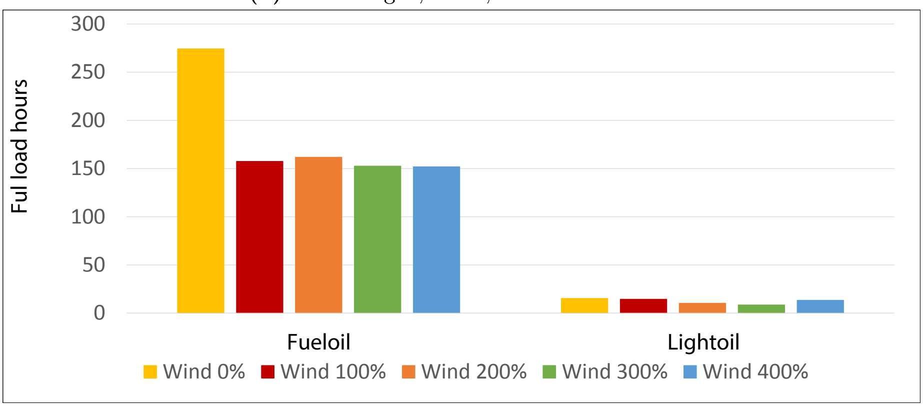


(c) Electricity price - with and without UC

Figure 5.1: Sensitivity to installed wind capacity



(a) Natural gas, wind, nuclear and coal



(b) Fueloil and lightoil

Figure 5.2: Full load hours for increasing wind capacity

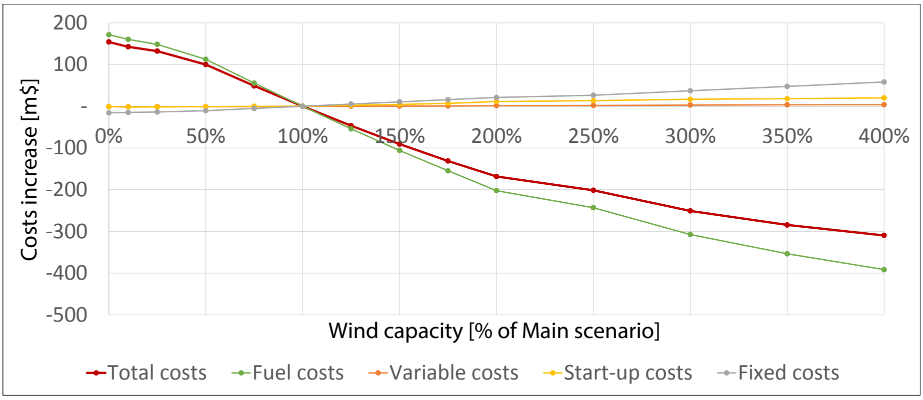
shown and indicates that more wind power in the system, increases the need for UC simulations as the difference rises from 3.7 to 4.4 % with double the wind capacity.

5.1.2 Transmission

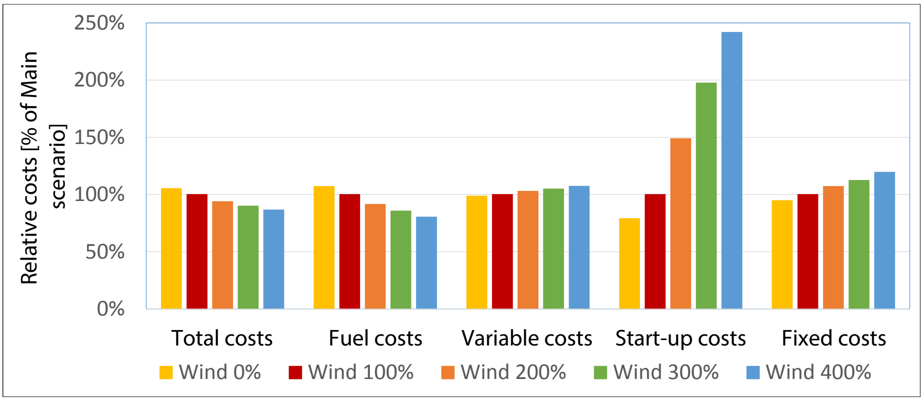
A severe decrease in transmission has the dysfunctioning of the electricity system as a result. The generation units cannot meet the demand in the regions at lower connectivity. At zero transmission the regions function as islands and a high amount of unserved demand is found (3.3% in Cairo and 14.0% in Middle-Delta). In the simulation of the system costs, the unserved demand is reflected in sky-rocketing variable costs, related to the spoof "unserved" generation unit. The resulting total system costs for both with and without UC are shown in Fig. 5.4a. An optimum transmission seems to be reached around 150%, where further increase does not bring any benefits for the system costs. To illustrate the consequences for the regions of a decrease in transmission, Fig. 5.4b depicts the full load hours per region. As the transmission decreases Cairo and Middle Delta are left to self-supply their energy needs, where an increase in transmission allows West Delta to take over some of the production for export to these regions that was before generated by East-Delta and Upper Egypt. Finally, the wind curtailment is shown in Fig. 5.4c for UC/no UC. From the big difference between the two, it can be concluded that curtailment due to transmission or curtailment due to UC are not independent.

5.1.3 Start-up costs

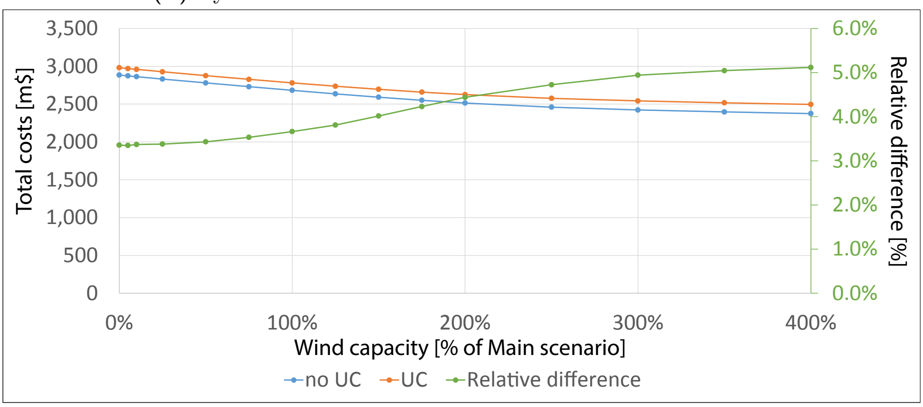
In Fig. 5.5a the impact of increased start-up costs on the system costs is seen. A trade-off is made between keeping plants on-line and avoiding start-up costs or shutting them down to save on fuel. At low start-up costs, some of the extra start-up costs is accepted. At higher start-up costs however the preferred tactic is increasing the fuel costs to keep the total start-up costs low.
In the composition of the generation profile, this translates in lower base-load and higher generation of peak-load plants, that are reluctant to go off-line for short periods between demand peaks /Fig. 5.5b). Namely natural gas steam turbines, fuel-oil and light-oil plants increase in production.



(a) Increase in system costs - with UC

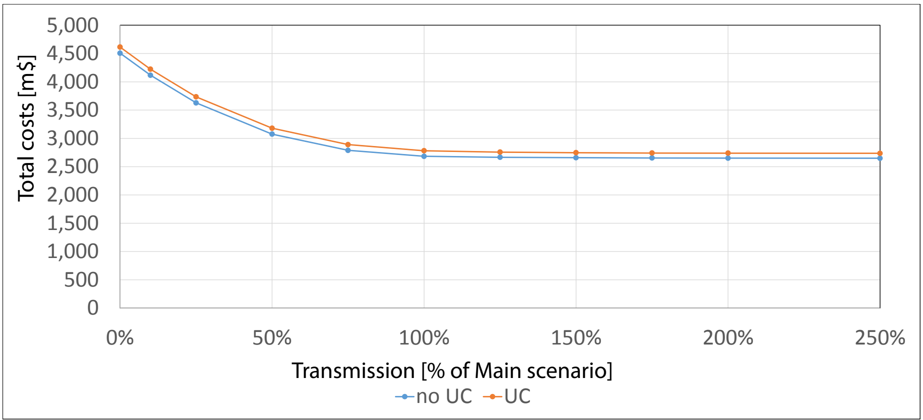


(b) System costs relative to the Main scenario - with UC

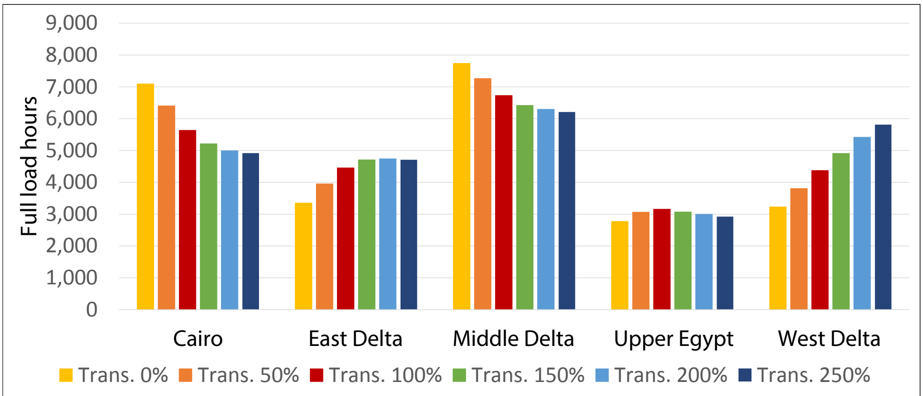


(c) Total costs with and without UC and relative increase of UC case compared to no UC

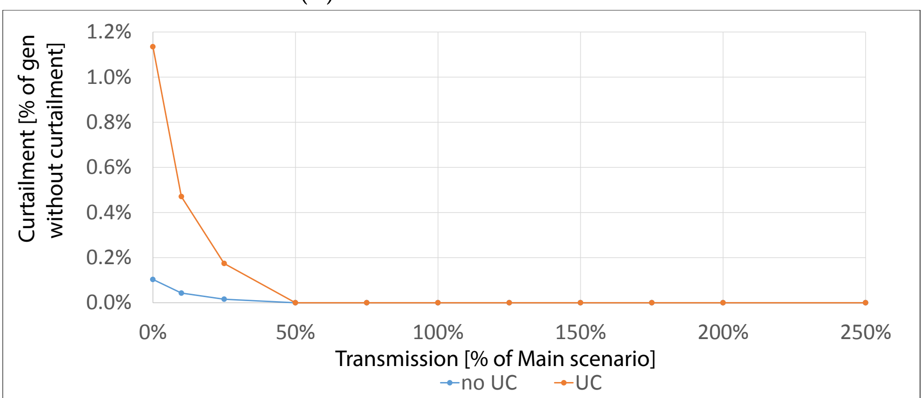
Figure 5.3: Sensitivity of system costs to wind capacity



(a) System costs - with and without UC

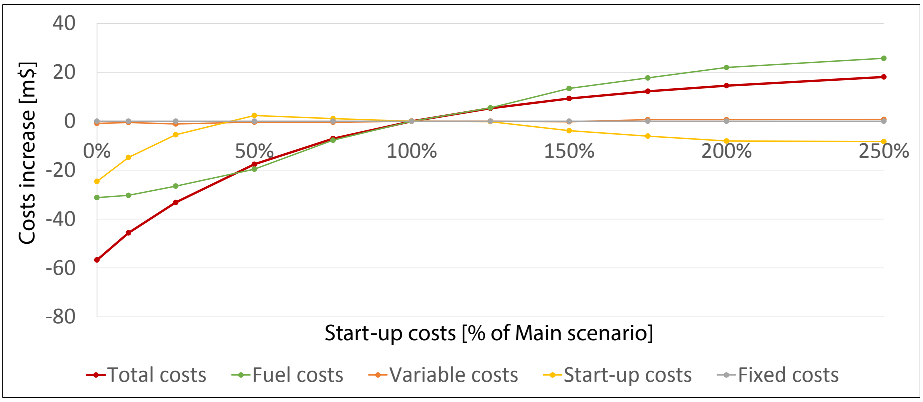


(b) Full load hours - with UC

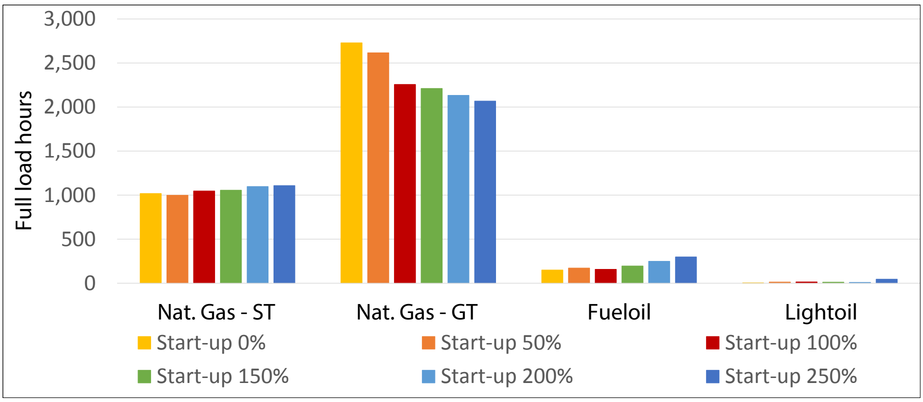


(c) Wind curtailment - with and without UC

Figure 5.4: Sensitivity to transmission capacity



(a) System costs



(b) Generation profile

Figure 5.5: Sensitivity to start-up costs

Accuracy [m$]	Calculation times [hh:mm:ss]
1	00:00:42
0.75	00:00:57
0.5	00:01:23
0.25	00:07:55
0.1	00:54:54
0.05	29:27:00

Table 5.1: Calculation times for simulations with different accuracies

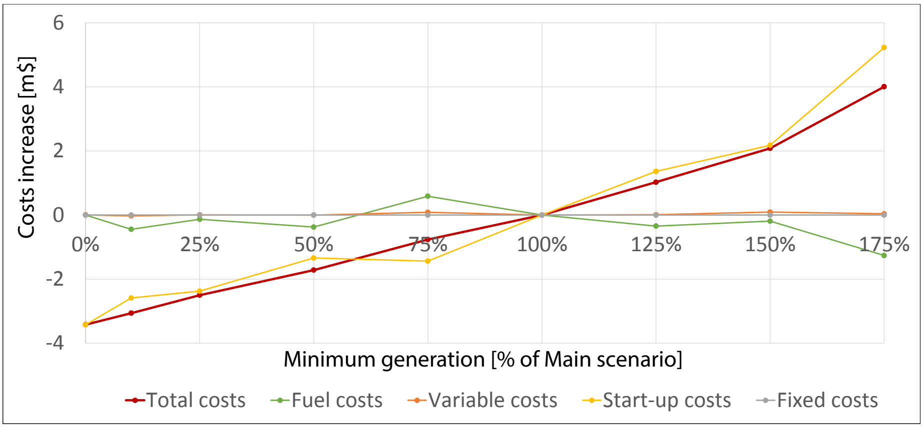
5.1.4 Minimum generation

Increasing the minimum generation of power plants makes them less flexible to variations in demand. At higher minimum generation, there is an increasing need to switch to plants with lower capacity when the generation of the on-line plants cannot be lowered further. This switching results in more start-ups and higher system costs. From the evolution of the FLHs, it can be seen that technologies with an original high share of minimum generation are producing less with a relative increase in minimum generation ("Nat. Gas - CC" has a 46% minimum generation in the Main scenario, coal 37% and nuclear 50%). These units are shut down instead of operating at lower generation shares. The opposite is true for "Nat. Gas - ST" with a minimum generation of 37% in the Main scenario. The "Nat. Gas - GT" is relatively stable as it has an intermediate minimum generation (34%) (Fig. 5.6). The flexible generation in still needed to cover peak demands and thus stays very stable and is therefore not shown here.

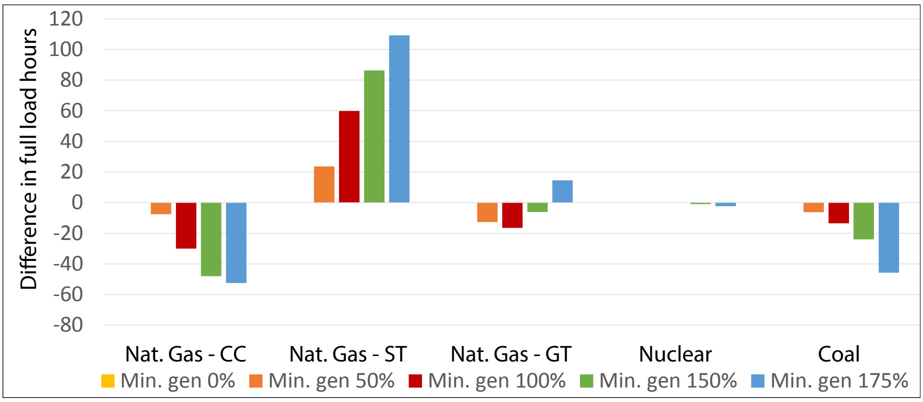
5.1.5 Accuracy

When checking the sensitivity of the results to the the accuracy of the simulations, an important variable of interest is the calculation time. Tab. 5.1 shows these values for the different levels of accuracy. It can be seen that the calculation time increases hyperexponentially; a trade-off thus exists between the quality of the results and the time of simulation.

The impact of the objective error on some of the relevant parameters is shown in Fig. 5.7. An increase in accuracy, results in lower system costs due to a more efficient unit dispatch (Fig. 5.7a). When going from an error of 1 m$ to 0.75 m$, the variable costs decline while the fuel costs increase. This is explained by a replacement of *unserved* demand - with no fuel costs, but very high variable

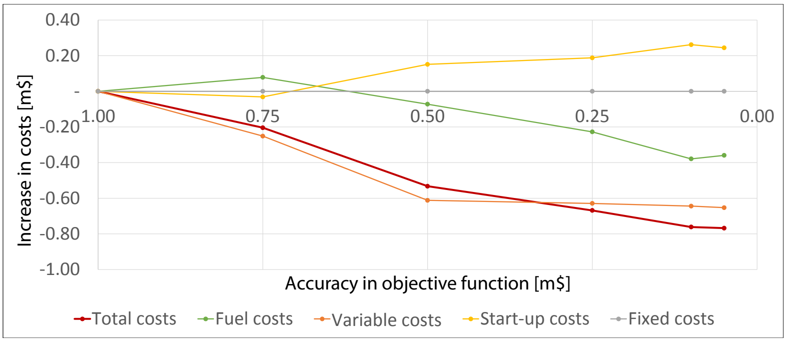


(a) System costs

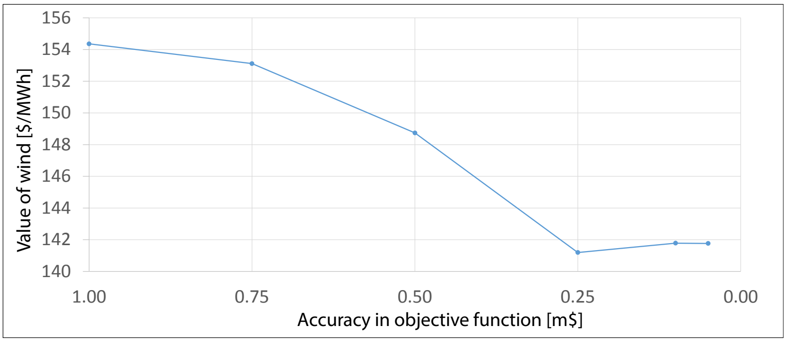


(b) Generation profile

Figure 5.6: Sensitivity to minimum generation



(a) Increase of system costs



(b) Value of wind

Figure 5.7: Sensitivity to accuracy of objective function

costs - by a power plant with higher fuel costs and normal variable costs. When increasing the accuracy further, the number of start-ups increase, lowering the need to keep expensive power plants on-line and thereby decreasing the fuel and variable costs. The relative decrease in the total system costs is very low; the most accurate simulation results in a decrease of 0.08% compared to the 1 m$ error simulation. The effect on the value of wind however, is more pronounced, with a decrease of almost 13$/MWh (Fig. 5.7b). As the electricity price (i.e. the marginal cost of production) in the regions with wind energy are very sensitive to which individual plants are generating, the value of wind is a reflection of this impact on the electricity price.

5.2 Sensitivity conclusions

From the sensitivity analyses, it can be seen that deviations in the wind capacity have large impacts on the generation profile and the system costs. The system's sensitivity to transmission capacity only becomes significant when the demand in certain regions cannot be reached. At this moment the variable costs rises drastically, imitating the costs of a black-out.
When it comes to unit sensitivity to unit commitment parameters, the changes in the system are relatively low even for unrealistically high deviations of the parameters. This indicates that the assumptions made about these parameters are not likely to compromise the results significantly and the model is robust with respect to these parameters.
An important notion is the sensitivity to the error in the objective function. As simulation runs with UC constraints have long calculation times it is interesting to be able estimate the loss in accuracy when setting the allowed error at higher values and thus shortening the simulation time. Depending on the topic of the study it can be a beneficial choice to allow more error on the results. However care should be taken when dealing with electricity prices or generation of individual power plants.

Chapter 6

Discussion

In this chapter the results and the sensitivities will be discussed and put in a broader perspective.

6.1 Discussion of master project results

6.1.1 Wind power integration and fulfilment of 2020 goals

From the results of the Main scenario it is shown that the 2020 goals, set by the NREA, to achieve a 20% share of electricity from renewable sources is not met in the simulations. Though the share of solar power is a bit lower than expected, it is mainly the wind power that is seriously under-represented. In comparison with the Renewable scenario where the wind power share is set as a requirement, the Main scenario has more than 50% less the required wind capacity (12.4 MW).
A possible explanation is the underestimation of the wind (and solar) FLHs in the model, as mentioned in the inputs chapter. the FLHs in the Balmorel model are an average for the whole of Egypt. The future wind farms, however are built on the most advantageous locations and therefore are bound to have higher FLHs. Especially the region close to the Gulf of Suez (East Delta in the

model) is seen to have high wind speeds. As no curtailment is seen in the Main scenario, the low share of wind in the system is not due to limitations of the power system, e.g. transmission or UC constraints.
To give an idea of the results with higher wind FLHs one can look at the wind sensitivity results, here a higher wind capacity can be interpreted as higher FLHs. As an estimation the wind share in the Main scenario is about 2.5 times smaller than the share required by the goals (in 2020, while the sensitivity in 2025 so not fully comparable). At 250% wind power, the curtailment is about 6%, which would best be solved by increasing the transmission capacities. (in this case with Upper-Egypt). The value of wind is also significantly lower than the electricity price which might be a problem for wind farm feasibility if no appropriate support schemes are in place.
Based on the Renewable scenario, it is possible (even with low wind FLHs) to reach the 2020 goals (and the chosen renewable shares for 2025 and 2030), with only a slight difference in overall costs compared to the most optimal Investment scenario, with significantly lower CO_2 emissions as a result. Very low levels of curtailment are seen in the Renewable scenario (compared to 250% of planned wind power capacity in the Main scenario). This is because the large majority of the wind investments are in East Delta, that is better connected than Upper-Egypt. The Renewable (or any other) scenario does not take any social and practical considerations into account with respect to building on-shore wind farms however. Social acceptance, wind farm feasibility, economic incentives etc. are considered when designing the EEHC expansion plan, but are not included in the model presented in this thesis.

6.1.2 Importance of unit commitment simulations

When comparing results of simulations with UC to simulations without any UC constraints in the Main scenario, some variables show relative differences. Differences in full load hours, though relatively small, are of importance for generator owners that might produce less than estimated with simulations without UC. Base load generation does not undergo a big impact, but peak load plants as fueloil and lightoil have a significant increase in FLHs, where "Nat. Gas - GT" units decrease in generation.
In terms of total system costs, differences of up to 3.7% were seen, which can be significant for when comparing scenarios, especially when high shares of fluctuating power like wind are present or with high start-up costs as was shown from the sensitivity analysis. It was also seen that e.g., the difference in total costs between the Investment and the Renewable scenario halved when omitting UC constraints compared to the UC case. Misleading results due to simulations without UC can easily lead to sub-optimal power system planning.
The differences in the electricity prices are larger as they are derived from

marginal costs, where a small change in unit dispatch can result in big differences. The impact of wrongly estimated electricity prices are important to the economic feasibility of any generation unit as well as for the provision for adequate support schemes for renewable energy. When applying UC constraints in power system simulations a balance between calculation time and accuracy needs to be found. For simulations with many time steps or in large power systems, the simulation time might be unreasonably long.

6.1.3 Transmission for the EEHC expansion plan

From the results of the Main+Trans scenario it is shown that Egypt would benefit from extra transmission on certain connections. As Cairo and Middle Delta are densely populated and have high electricity demands, they need strong connections to the regions with high generation capacity and lower consumption. An increase in capacity on the transmission lines interconnecting the Delta+Cairo region (East and West Delta with high production and Cairo and Middle Delta with high loads) would strengthen the power system. From the difference in endogenously invested transmission capacity in the Main+Trans and the Main+Invest scenario, the importance of the location of power units is seen. Placing new generation in regions with high demand will prevent the need for large grid capacity expansions, though in reality it is often difficult to install large units in densely populated areas. From this difference in transmission capacity between the two scenarios, it can also be concluded that the Main scenario is sensitive to errors in locating the future units of the EEHC plan. If one large unit was wrongly located in the input data, the requirements for the transmission lines could change significantly. The simplification of the seven transmission zones, used by the Egyptian transmission company, to five regions in the simulations of this project might also have a relevant impact on the results. The transmission lines between some of the zones that are joined in one region, are potential extra bottlenecks. Ideally a better representation of the Egyptian electricity grid would be incorporated in the model, where, e.g. voltage levels are taken into account, which would make for stricter transmission constraints.

6.2 Recommended improvements of the model and the input data

The project discussed in this thesis aims to give an impression of how the future Egyptian energy system might look with increased wind penetration. The timespan for the project does not allow the accuracy in input data and results that it could achieve at in longer project-time. Better input data could greatly improve the results of the simulations. In this project Egypt is modelled as a country disconnected from other countries. This of course is not the case and future large interconnections are expected to be built between Egypt and its neighbouring countries (e.g. Saudi Arabia). The inclusion of these connections would be relevant for accurately simulating the Egyptian power system. As mentioned before, the correct wind profiles and FLHs for the individual wind farms or at least the regions would be a great enhancement of the simulation. With respect to the transmission grid a more detailed representation is important for the results. As there is a current parallel study focused on grid simulations of the Egyptian system, a correspondence, exchange of results or even an approach integrating both studies could be beneficial for the simulations. Regarding UC constraints, accurate UC parameters for the individual plants are needed to make the UC results more realistic compared to this project where average values are used from a different nation. The impacts on individual plants could then be examined as well. It could be interesting to apply investments with UC which according to literature can result in significantly different energy planning and has a relevant impact in system costs.

Chapter 7

Conclusion

In this project the impacts of a big increase in wind power capacity in Egypt were examined. The generation expansion plan, set-out by the Egyptian government, was used as a basis for simulating the future Egyptian power system. It was found that the foreseen capacity for 2020 does not meet the 20% renewable energy goal, though this could be due to underestimated FLHs in the model. To support the Egyptian expansion plan, the future transmission grid will need to expand in order to provide sufficient connections between Cairo and the Delta region. This is especially the case if larger shares of wind power would be integrated in Egypt, when extra transmission is needed to prevent wind curtailment. From the sensitivity results it can be concluded that wind power integration is viable in the Egyptian power system up to a certain level at which the wind curtailment becomes excessive, the VOW is significantly lower and the FLHs of the remaining power units have decreased severely. It was shown that adding UC constraints to simulations of the Egyptian power system with wind power integrated, changed the results significantly compared to simulations without UC. Variables as system costs and especially electricity price show a difference compared to the no UC case. When bigger shares of wind power are integrated, the impacts on the system costs of including UC constraints grow. A serious draw-back of including UC in power system simulations is the calculation times that rises drastically with increasing complexity.

Appendix A

EEHC generation expansion plan

Plant Name	Fuel	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Suez Gulf Wind	*wind*			550		200	400									
East-West Nile Wind	*wind*			200	710	600	700	950	950	950	950	650	650	650	650	650
Solar units	*solar*					150	50	100	50	100	50	100	50	100	50	100
Photo Voltatic cells	*solar*			35	20	220	250	400	300	300	250	250	250	300	300	400
*Damitta west (CC) **	*gas*	500				250										
6 october (CC)	*gas*		150	450			300									
*Abu Kir (ST) **	*gas*	1300														
*Ain Sokhna (ST) **	*gas*			1300												
Banha (CC)	*gas*		500	250												
Giza North (CC)	*gas*		1000	750	500											
Dairout BOO (CC)	*gas*						1500	750								
Suez (ST)	*gas*				650											
Damanhour (CC)	*gas*						1000	500								
El_Suief (CC)	*gas*						500	250								
Mahmoudia (CC)	*gas*						300	150								
El_Shabab (CC)	*gas*					500										
Mini & Small Hydro Units	*hydro*						32									
Helwan South (ST)	*gas*						1950									
Cairo West (ST)	*gas*							650								
Assuit (ST)	*gas*						650									
Damitta west 2 (CC)	*gas*						1500	750								
Safaga (ST)	*gas*							650	1300							
Bani Seuif (CC)	*gas*							1500	750							
Alex East (CC)	*gas*							1500	750							
Sidi Krir 2 (CC)	*gas*							750								
Qena (ST)	*gas*								1300							
Cairo South (ST)	*gas*								1300	650						
Oyoun Mousa coal (ST)	*coal*								1000	2000						
Oyoun Mousa ext (ST)	*gas*									650						
Kafer El-Dawar (ST)	*gas*									650						
Abo Kir (ST) New	*gas*										650					
port Said Ext coal	*coal*										2000	2000	1000	2000	1000	2000
Steam Units	*gas*												1300		1950	
Combined Cycle Units	*gas*											1000	2250	1500	1250	1500
Nuclear	*nuclear*											1650		1650		1650

Figure A.1: EEHC generation expansion plan in MW

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