NATIONAL TECHNICAL UNIVERSITY OF ATHENS
SCHOOL OF MECHANICAL ENGINEERING
FLUIDS SECTION
LABORATORY OF THERMAL TURBOMACHINES

Methods for Assessing the Evolution of the Greek Power System

Diploma Thesis

IOANNIS SFIKAS

Supervisor: K. Mathioudakis

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ABSTRACT

The present thesis deals with methods for assessing the evolution of the Greek Electricity System, with special emphasis on the role of the Natural Gas Stations. To this end, a model was developed so as to examine the evolution of the Greek Energy System in a computational package by applying different optimization approaches. The examined time period considered is up to the year 2040.

The first part of this thesis presents a literature review of the different modelling methods of a country's broader energy system. The required input data as well as the basic results of these models are also presented. Then, the determination of the data that are required in order to model the Greek Power System as well as the possible sources of this data is conducted.

The second part contains the collection of historical and current data regarding the basic quantities need in order to describe the Greek Power System. Also, the projections regarding the evolution of these quantities over a period of time until 2040 is presented. Subsequently, the methods of optimizing the Greek Power System are presented. These methods are the method of minimizing the annualized cost of the power system, of maximizing investments in new power plants, of maximizing the gross added value of such investments as well as of minimizing the national monetary outflows. In order to evaluate these methods, the initial results are compared with the corresponding results of a commercial software package as well as with those of the recent National Plan for Energy and Climate.

The comparative evaluation of the model's results generated for each optimization method is presented in the last part of this thesis. Overall, the present work attempts to introduce several criteria for optimizing a power system by focusing not only on minimizing the total cost of a power system, but also on the macro-economic results-sizes of investments in new power plants.

ΕΘΝΙΚΟ ΜΕΤΣΟΒΙΟ ΠΟΛΥΤΕΧΝΕΙΟ
ΣΧΟΛΗ ΜΗΧΑΝΟΛΟΓΩΝ ΜΗΧΑΝΙΚΩΝ
ΤΟΜΕΑΣ ΡΕΥΣΤΩΝ
ΕΡΓΑΣΤΗΡΙΟ ΘΕΡΜΙΚΩΝ ΣΤΡΟΒΙΛΟΜΗΧΑΝΩΝ

Μέθοδοι Αποτίμησης της Εξέλιξης του Ελληνικού Ηλεκτρικού Συστήματος

Διπλωματική Εργασία

ΣΦΗΚΑΣ ΙΩΑΝΝΗΣ

Επιβλέπων: Κ. Μαθιουδάκης

ΠΕΡΙΛΗΨΗ

Η παρούσα διπλωματική εργασία πραγματεύεται το θέμα της εξέλιξης και βελτιστοποίησης του Ελληνικού Ηλεκτρικού Συστήματος δίνοντας παράλληλα ιδιαίτερη έμφαση στον ρόλο των μονάδων Φυσικού Αερίου. Για τον σκοπό αυτό δημιουργήθηκε μοντέλο βελτιστοποίησης της εξέλιξης του Ελληνικού Ενεργειακού Συστήματος μέσω κατάλληλου υπολογιστικού πακέτου. Η χρονική περίοδος που θα εξεταστεί θα είναι μέχρι το έτος 2040.

Στο πρώτο μέρος παρουσιάζεται μία βιβλιογραφική ανασκόπηση των διαφόρων μεθόδων μοντελοποίησης του ευρύτερου ενεργειακού συστήματος μίας χώρας. Παρουσιάζονται επίσης τα απαιτούμενα δεδομένα εισόδου καθώς επίσης και τα ευρύτερα αποτελέσματα αυτών των μοντέλων. Εν συνεχεία, επιχειρείται η εκλογή των απαιτούμενων δεδομένων για την μοντελοποίηση του Ελληνικού Ηλεκτρικού Συστήματος καθώς και οι πιθανές πηγές αυτών των δεδομένων.

Το δεύτερο μέρος περιέχει αρχικά τη συγκέντρωση ιστορικών και σημερινών δεδομένων σχετικά με τα βασικά μεγέθη που περιγράφουν το Ελληνικό Σύστημα Ηλεκτροπαραγωγής. Επίσης, η εξέλιξη αυτών των μεγεθών σε χρονικό ορίζοντα μέχρι το 2040 παρουσιάζεται. Εν συνεχεία, προτείνονται οι μέθοδοι υπό τις οποίες θα πραγματοποιηθεί η βελτιστοποίηση του Ελληνικού Ηλεκτρικού Συστήματος. Αυτές οι μέθοδοι είναι η μέθοδος της ελαχιστοποίησης του ετήσιου κόστους του ηλεκτρικού συστήματος, της μεγιστοποίησης των επενδύσεων σε νέες μονάδες ηλεκτροπαραγωγής, της μεγιστοποίησης της εγχώριας προστιθέμενης αξίας τέτοιων επενδύσεων καθώς επίσης και της ελαχιστοποίησης των εκροών συναλλάγματος σε εθνικό επίπεδο. Για την αξιολόγηση αρχικά αυτών των μεθόδων, πραγματοποιείται η σύγκριση των αρχικών αποτελεσμάτων με τα αντίστοιχα αποτελέσματα ενός εμπορικού λογισμικού καθώς και με τα αποτελέσματα του πρόσφατου Εθνικού Σχεδίου για την Ενέργεια και το Κλίμα σε ότι αφορά την εξέλιξη του Ηλεκτρικού Συστήματος.

Η συγκριτική αξιολόγηση των αποτελεσμάτων του μοντέλου το οποίο δημιουργήθηκε για κάθε μέθοδο βελτιστοποίησης παρουσιάζονται στο τελευταίο μέρος της παρούσης εργασίας. Συνολικά η παρούσα εργασία επιχειρεί την εισαγωγή νέων κριτηρίων βελτιστοποίησης ενός ηλεκτρικού συστήματος εστιάζοντας πέρα από την ελαχιστοποίηση του συνολικού κόστους ενός ηλεκτρικού συστήματος, και στα μακροοικονομικά αποτελέσματα-μεγέθη των επενδύσεων σε νέες μονάδες ηλεκτροπαραγωγής.

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First of all I would like to thanks Professor Konstantinos Mathioudakis for giving me the opportunity to work on a topic for my diploma thesis that deals with an issue that will be in the spotlight the next years. Although it was a special topic that for the first time a diploma thesis in the Laboratory of Thermal Turbomachines was dealing with, the experience and the guidance of Professor Mathioudakis proved to be extremely helpful for the completion of my thesis.

Also I have to acknowledge the contribution of Mr. Kyriakos Kapsalis, Mechanical Engineer and Economist, who as an energy expert evaluated some of the initial results of my thesis.

Last but not least, I would like to express my gratitude to my family for their unconditional love and guidance during my studies. A special thanks to all of my friends for standing by me, both in good times and especially during the bad ones.

Ioannis Sfikas
October,2019

Methods for Assessing the Evolution of the Greek Power System

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Symbols Abbreviations

BUENAS	Bottom-Up Energy Analysis System
CCGT	Combined Cycle Gas Turbine
CET	Carbon Emission Trading
CGE	Computable General Equilibrium
CRES	Center for Renewable Energy Sources and Saving
DB	Deutsche Bank
DESFA	Hellenic Gas Transmission System Operator
DIME	Dispatch and Investment model for Electricity Markets in Europe
EEA	European Environment Agency
EL.STAT.	Hellenic Statistical Authority
ELETAEN	Hellenic Wind Energy Association
ETS	Emission Trading Schemes
ETSAP	Energy Technology Systems Analysis Program
EU	European Union
FIT	Feed in Tariff
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GVA	Gross Value Added
GVA	Gross Value Added
HVAC	Heating Ventilation and Air-Conditioning
i	Technology Index
IEA	International Energy Agency
IOBE	Foundation for Economic and Industrial Research
IPTO	Independent Power Transmission Operator
IRENA	International Renewable Energy Agency
ISEIC	Interconnected System's Energy Imports Cost
LCOE	Levelized Cost of Electricity
LEAP	Long-Range Energy Alternatives Planning
MAED	Model for Analysis of Energy Demand
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MS	Member States
NEMS-RSDM	National Energy Modelling System – Residential Sector Demand Module
NGFC	Natural Gas Fuel Costs
NIA	National Impact Analysis
NIIs	Non-Interconnected islands system
NPV	Net Present Value
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
OECD	Organization for Economic Co-Operation and Development
OF	Objective Function
PAMS	Policy Analysis Modelling System
PEM	Partial Equilibrium Model
POLES	Prospective Outlook on Long-term Energy System
PPC	Public Power Corporation
RAE	Regulator Authority of Energy
REEPS	Residential End-Use Energy Planning System

REF	Reference
RES	Renewable Energy Sources
SD	Systems Dynamics
SMP	System Marginal Price
TAPC	Total Annualized Production Cost
WEM	World Energy Model
YPEN	Hellenic Ministry of Environment, Energy and Climate Change
z	Year Index

1 Introduction

This thesis has as a goal the study of methods for assessing the evolution of the Greek Power System as well as the investigation of the role that the Natural Gas Stations will have under different scenarios by constructing a new model and introducing new optimization approaches. This introduction aims at presenting the basic structure of the present thesis as well as to define the goal of this study.

The evolution of power systems and more generally of energy systems can be analyzed by using different modelling approaches. Literature review has been conducted in order to assess the different modelling approaches. The two main approaches are the Top-Down and the Bottom-Up Energy Modelling. There is a vast array of existing models that despite the fact that they have the same goal, their modelling approach is completely different. The description of these modelling approaches is presented in Chapter 2.

The literature review of the various available models also provides information regarding the basic input and output data that are essential for modelling an energy system. Modelling an entire energy system in not the purpose of this thesis. However, modeling an energy system proved to be similar to the one of a power system in terms of both the nature of the input-output data as well as the goals of the modelling process. Therefore, the data collection for simulating or optimizing a power system is being presented in Chapter 3.

Data requirements for optimizing the Greek Power System are divided into historical-current period’s data and projections regarding the evolution of basic indicators of a power system. The data collection for both periods is being presented in Chapter 3.

Chapter 4 presents the different optimization approaches that were introduced in this thesis. Four approaches were introduced: the Total Annualized Power System’s Production Cost Minimization, the Investments Maximization, the Value Added Maximization and the Monetary Outflows Minimization. In order to assess the credibility and the performance of these approaches a comparison between these simplified models and a modelling tool developed by Stockholm’s Environment Institute has been conducted. In addition, the recent proposals of the Greek Energy Ministry in the National Plan for Energy and Climate were utilized as a reference point in order to assess the outputs of the model that was constructed in this thesis. Following the introduction of these approaches, the input data as well as the constraints for optimizing the evolution of the Greek Power System under different scenarios are presented in Chapter 5.

The scenarios developed and examined in this thesis were a reference scenario, a scenario of penetration of offshore wind energy farms in the Greek Power System, a scenario with different demand projections as well as a scenario of 100% decommission of Lignite Power Plants. The results and the interpretation of the output data are presented in Chapter 6.

Chapter 7 presents the final remarks and the conclusions of this thesis.

2 State-of-the-art regarding Energy Systems Modelling Approaches

As mentioned in the introduction, modelling an energy system can be conducted by different methods and perspectives. As a consequence, the following literature review shows that there is scientific controversy in modelling energy systems due to the different nature of the existing energy modelling approaches. The first broad category of models are the detailed techno-economic (or process-oriented) models. These models try to understand the penetration and the cost of new energy technology or policy based on technical parameters. Although, process-technology oriented, these models fail to forecast the economic, structural, or employment societal effects. That’s why, macroeconomic models can bridge this gap, by simulating sector-specific future energy demand and supply. These models encompass economic growth, employment and foreign trade variables. Inputs of this macroeconomic models are mainly economic and financial parameters such as energy price fluctuations, monetary and fiscal policies. As a result, specific technology improvements or sectoral policies and related emissions, are poorly projected by macroeconomic models.

Therefore, there are two general methods of modelling an energy system: the top-down method and the bottom-up. Bottom- up models have been developed mainly from engineers, scientists and energy supply companies and they reflect the detailed techno-economic concept regarding energy modelling. On the other hand, top-down models have been constructed and used by economists, public administrators et al. The macroeconomic element in energy modelling can be reflected in the top-down method.

Taking into consideration both types of energy modelling, and their advantages as well as their limitations, a hybrid energy model has been developed from various scholars and organizations (Hourcade et al., 2006; Jochem et al., 2007;Schade et al., 2009; Catenazzi, 2009) in order to address the gaps of each model.

2.1 Top-Down Energy Modelling

Top-Down models attempt to analyze the economic impact of energy and/or climate change policies in a national, regional or international level, expressed in monetary units. Macroeconomic models take into account macroeconomic factors such as the economic growth, inter-industrial structural changes, demographic forecasts and price trends (excluding energy related technological advancements and innovations or intra-industrial structural alterations). The goal of macroeconomic models is to reach a market equilibrium point by maximizing the consumer welfare. These models have been used in the recent years as an evaluation method of various general and climate policy actions (emission trading schemes (ETS), CO_2 taxes, FIT in the renewables market etc.). The current top-down models try to encompass in their energy demand forecasting tools, technological and economic feedbacks (Löschel, 2002; Böhringer and Löschel, 2006) as well as non-price determinants (technical standards, norms etc.; Worell et al., 2004). In the following paragraphs, four different types of top-down models are presented: the input-output models, econometric models, computable general equilibrium models and system dynamics models.

2.1.1 Input-Output Models

This method of top-down modelling has its foundations on the analysis of Francois Quesnays *Tableau économique* (1758) and Leon Walras and Wassily Leontiefs *Input-Output Economics* (1966). It has been applied for the purposes of the assessment of the total flow of products and services within a country, divided into specific sectors and users of a national economy, in terms of added value. Input-Output tables fit better in short-term energy policies evaluation rather in long-term ones due to the fact that they describe the current economic status based on historical data (Catenazzi, 2009). As Nathani [1] stated, these type of models separate the final energy demand of a country into two broad categories: a production-oriented that accounts the energy required for the production of the goods in a country and a consumption-oriented that sums the energy required for producing the consumable goods

Input-Output models have been constructed by Nathani for Switzerland and Germany. In the latter case, input-output tables generated valuable information regarding the interrelationships between material use and the final energy demand. Despite this fact, it can be stated that model improvements are vital so as to minimize uncertainties related to specific industries' energy demand.

Nathani also suggested that the input tables should contain data regarding the overall product life cycle. This means that based on a life cycle analysis approach, at every step of a good's production the energy used should be identified and accounted. All in all, Nathani claims that the final energy consumption of a material good is highly determined by the production process, the use of a product as well as its disposal. An input-output model takes also into account data related to the imported goods, either for direct final consumption or imported goods that are part of the supply chain of domestic product, as well as materials required for the production of non-material goods (i.e. electricity or services sector).

2.1.2 Econometric Models

Econometric Analysis is a fundamental theory of economics. In energy modelling, econometric models are open-ended, growth oriented macro-econometric models requiring time series data analysis, with no equilibrium provision.

Econometric models represent a vast array of macroeconomics models. The construction of an econometric model aims at evaluating and forecasting the impact of a proposed energy policy change. In other words, having as inputs time series of various macroeconomic variables, econometric models try to predict (with regression tools) the impact of a specific energy policy change in a specific macroeconomic variable. For instance, examining an ecological tax reform, as inputs of an econometric model could be the tax imposed on different products according to their environmental impact as well as each products consumption level and as output the estimated reduction in the consumption of these goods. [2]

The major drawback of econometric models is their dependence on huge amount of data. Data availability is not guaranteed in the case of small macro-econometric models. Thus, data quality play a crucial role as they add an extra factor of uncertainty in the final model output.

2.1.3 Computable General Equilibrium (CGE) Models

These models are based on the general equilibrium theory which was first developed by Léon Walras in the 1870s and later on by Vilfredo Pareto in 1906 and Kenneth Arrow-Gerard Debreu in the 1950s. CGE models assume that all markets of an economy are in a perfect equilibrium with no shortages or excesses in the demand or supply side. This equilibrium assumption eliminates energy efficiency gaps and as a result the significance of market inefficiencies are ignored.

In general, CGE's assume a general equilibrium point (REF) which is then affected by a policy shock. Standard CGE's have two main elements: the model structure which is basically the system of equations that need to be solved in order to attain the new equilibrium point and the database. The database may have relevant information regarding the capital, the labour or the resources that are essential for the production of a good or a service. All of these information is divided into two parts: the flow of spending and income in an economy and parameter values. Spending and income flows usually are the demand for and the supply of goods and services. [3]. In the following figure an economic system described by a CGE model is presented.

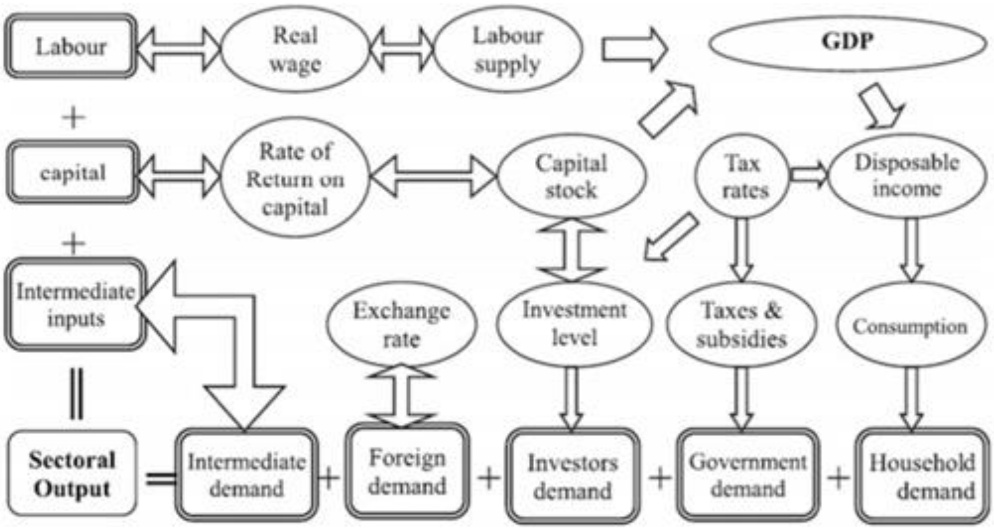


Figure 2.1: Economic System Analysis under CGE modelling approach

Being a macroeconomic model, CGE fails to include technological details (which are of great importance for policy analysis) in its core. CGE models try to conduct an impact analysis, on a socio-economic and environmental level, instead of searching for an optimal set of policy measures. Using CGE for policy analysis, when an exogenous economic parameter is changed, a new general equilibrium is computed. The main advantage of CGE models over Partial Equilibrium Models (these models focus on policy impact on one specific sector of the economy) is the multi-sectoral image of the economy that is produced (i.e. a general equilibrium point of all the interdependent economic sectors) [4]. Some examples of CGE models are the GEM-E3 and the GEMINI-E3 models [5].

2.1.4 System Dynamics Models

Systems Dynamics (SD) approach was developed by Forrester (1958, 1962, 1971, 1980) in the 1950s at the Massachusetts Institute of Technology (MIT). The long-term behavioural dynamics of a complex and interacting social system have been described by the dynamic changes (differential equations) of the assumed interdependencies, among the components of the defined social system. The interconnections that arise between the flows and central components of the defined system, can be described by feedback loops (non-linear differential equations). Long-term provisions and developments in the energy sector can be projected by SD models.

An illustrative example in order to define the inputs and outputs of system dynamics models, are the elements of the TIMES-model. TIMES which is a typical SD model, generates the structure of a local, national, regional or global energy system as well the dynamics of this energy system over a long-term horizon. The user of a model among others provides the estimated end-use energy service demands, the energy related equipment across every sector as well as future sources of primary energy supply. With these inputs, the TIMES model has as a goal to provide the energy supply at a minimum national, regional or global cost. At the same time, it gives guidelines for equipment investment, primary energy supply and energy trading. Finally, the TIMES model provides a clear image on the environmental emissions [6].

Criticism regarding the inability of SD models to predict future sectoral technologies improvements, is one of those that top-down models are facing.

2.2 Bottom-Up Energy Modelling

Bottom-up models focus on the technological aspects of the energy modelling problem rather than the macroeconomic ones. To be more specific, these kind of models implement a business economic perspective for the economic valuation of the technologies that constitute the energy mix. Macroeconomic factors as well as the impacts of energy and climate policies are not being processed by this models. Therefore, the technological development aspect and the deployment of new and innovative technologies that characterizes bottom-up models, cannot make them effective and accurate for long-term energy demand and supply forecasting. The majority of bottom-up models are optimization or simulation ones and recently multi-agent ones.

Scholars, who use these models, try to discover the technologies that are suitable for the energy mix of a country, by examining policy impact, investments, costs and benefits of energy efficiency measures, by describing synergy-effects between sectors of the economy as well as sectoral costs and benefits [4].

The four main types of bottom-up models are the following: Partial Equilibrium Models, Optimisation Models, Simulation Models and Multi-Agent Models.

2.2.1 Partial Equilibrium Models (PEM)

Partial Equilibrium Models have the same fundamentals with the CGE models. Their difference can be found on the fact that PEM focus only on one sector or a subset of sectors. By excluding interrelations of the greater economy, PEM can apply more technological details than CGE models can. Many PEM have been developed in the past years but the most credible ones are the POLES model (Prospective Outlook on Long-term Energy System) from Enerdata, the WEM (World Energy Model) of the International Energy Agency and the PRIMES Energy System Model of the European Commission. It is important to state that the aforementioned models include macroeconomic and process-oriented aspects, in an effort to minimize the gap between techno-economic and the macroeconomic approach.

Enerdata developed the POLES model which is based on a simulation process via the energy demand and supply of each national or regional territory (analysis of the international energy markets for seven world regions, eleven sub-regions, 32 countries and 40 technologies of power and hydrogen production) is being affected by the international price fluctuations as well as technological and economic limitations, in a past period of time.

A typical PEM like POLES, uses a learning process, in order to conduct a simulation. Learning curves (either one-factor or two-factor), that are being used as inputs in the POLES model, are usually representing the relationship between the investment costs of new technologies and cumulative capacity. This learning process determines the future changes in the costs and in the energy that will be produced form new energy technologies and is a common tool when analysing immature scenarios of future deployment that prioritize renewable energy technologies. Having, this past data in the form of learning curves, the POLES model describes the progression of the energy mix in a long-term horizon [7].

Medium as well as long term sectoral and regional forecasts in terms of energy demand, power generation, investments from the supply side and net changes of demand side investments, can be extrapolated by the WEM model. This model has various demand modules (i.e. final energy demand of transport or residential sector etc.), a refinery module, a power generation module, three fossil fuel supply modules (oil, coal and gas) and amongst others a module that estimates the CO_2 emissions from oil, coal and gas power generation, for different sectors and regions.

The PRIMES model, amongst others, can conduct an impact analysis for instance of carbon emission trading (CET) schemes or energy efficiency policies, by simulating a market equilibrium for energy demand and supply for each EU MS. It also takes into consideration the national energy price market conditions.

2.2.2 Energy System Optimisation Models (ESOMs)

Energy System Optimisation models (ESOMs), having energy prices as well as quantity demanded fixed in the market equilibrium point, attempt to identify the optimal set of technologies in order to reach a specific goal, minimizing costs under specific constraints. In other words, ESOMs have a bottom-up approach for the technology specifications and by applying linear programming techniques with the goal to minimize the present cost of energy that is being produced, they conduct an optimisation for the installation of energy technology capacity [8].

Being optimisation models, ESOMs generally have constraints that guarantee energy system’s credibility and performance. Amongst various outputs, ESOMs forecast the energy technology capacity and utilization, the range within the commodity prices will fluctuate as well as the emissions from the energy system as a whole. On the other hand, regarding the inputs of an ESOM model, these can be tracked in five broad categories : demand of several economic sectors (i.e. agricultural, industrial, transportation etc.), emissions data, energy carriers (i.e. fossil fuels, nuclear, renewables etc.), materials and technological state of the art [9].

One model that represents this category is the MARKAL model. MARKAL describes energy demand and supply using a dynamic modelling method. MARKAL is a combination of a detailed bottom-up method with macroeconomics variables. This model tries to construct a cost effective energy system with restraints on emissions. It also takes into account price policies (i.e. taxes) and the deployment of new technologies and trends as far as the technological improvements is concerned.

One of the MARKAL model's offspring is the well-known TIMES model, which encompasses identical modelling approaches with the MARKAL but it contains some additional capabilities. For instance, flexibility in the time horizon, data decoupling, process generality, commodity related factors, climate change equations etc.(ETSAP, 2005). In the figure 1.2 an illustrative version of the structure of a TIMES model developed for Norway is presented [10].

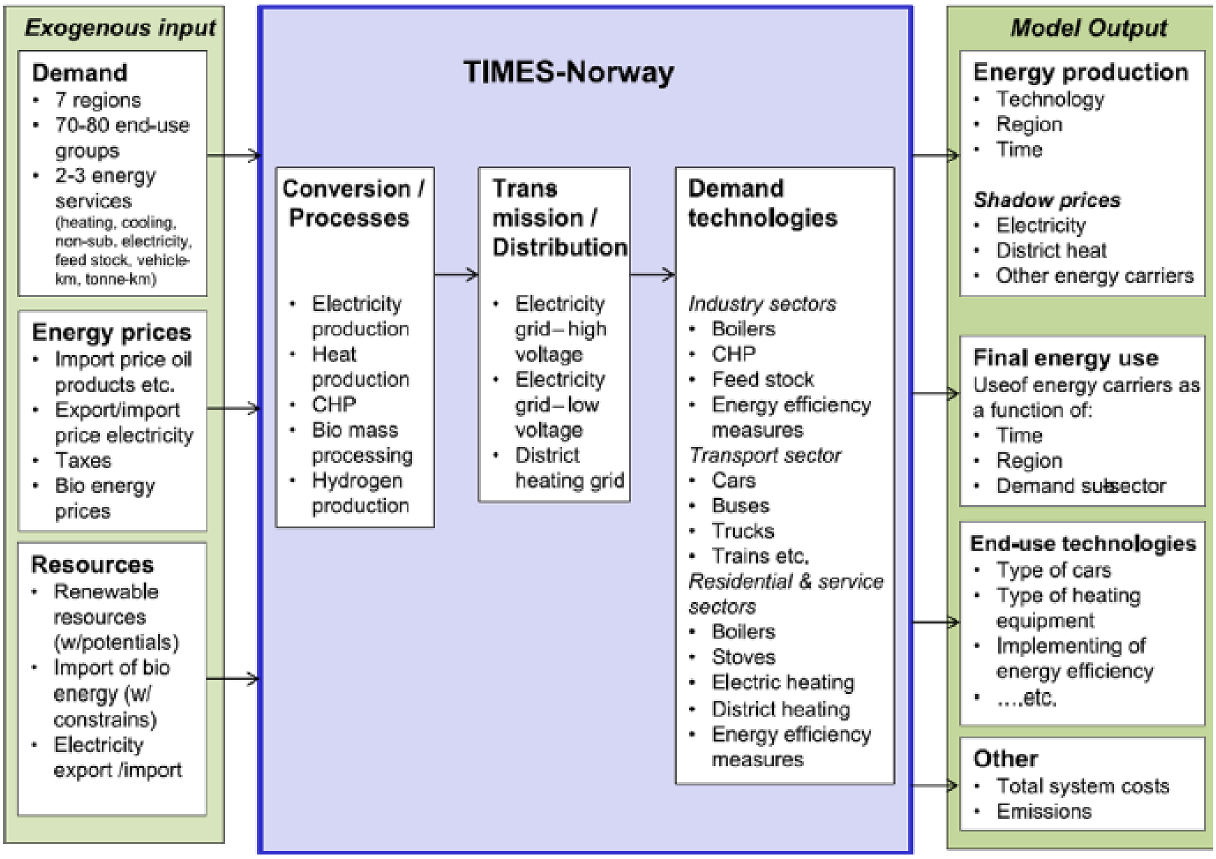


Figure 2.2: TIMES model developed for Norway's Energy System

Other versions of the MARKAL model is the Euro MM (European Multi-regional MARKAL), the MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impact) and the DIME (Dispatch and Investment model for Electricity Markets in Europe).

A usual constraint of ESOMs, is the standardization of the energy conversion technologies and the final energy use, due to the fact that these models require information on investment and operating costs. As a consequence, these models cover only certain technological areas and final energy sectors. For example, in the service and industrial sector where there is a vast array of technological choices, the MARKAL model fails to predict the energy demand, as a result of the lack of cost information. Finally, someone can claim that low energy demand forecasts are observed, as a result of the market imperfections and obstacles in various final energy sectors that cannot be taken into account by the MARKAL model.

2.2.3 Simulation Models

Simulation models have as a goal to define a descriptive, quantitative image of energy demand as well as energy conversion by taking into consideration exogenously determined drivers and technical data. Cost minimizing objectives are not applied in this kind of models. Determinants such as income, population, employment, living area, mileage, energy prices, government policies etc. and their change, are fundamentally required in order to replicate the final user behavior and thus the demand side. Boundary Conditions (e.g. energy and climate change policies) as well as scenarios of economic and demographic development are linked with the aforementioned determinants.

The liberalization and restructuring of many electricity markets imply that the traditional cost minimization models may not reflect the potential imperfect competition of market stakeholders. This requirement is fulfilled by flexible simulation models that take into consideration market imperfections. Several simulation models have been developed such as the Residential End-Use Energy Planning System (REEPS); World Energy Model (WEM); Mesures d'Utilisation Rationnelle de l'Energie (MURE); and the National Energy Modelling System – Residential Sector Demand Module (NEMS-RSDM) (Mundaca and Neij, 2009).

In addition, game theory models where the interaction of energy market stakeholders, market design aspects and market power analysis are replicated, can be categorized as simulation models. Accounting frameworks is a simple form of a simulation model which reports the physical and economic flows of the energy system (Heaps, 2002; Mundaca and Neij, 2009). Instead of replicating stakeholders decisions, accounting frameworks model reports the results of an assumed development (i.e. penetration of a new technology in the energy market) in a descriptive manner or in a prescriptive one. Overall, this method is used in order to forecast future energy demand of final energy sectors but for decision making process is not suggested (mainly for its simplicity as a model). Some examples of accounting frameworks models are the Long-Range Energy Alternatives Planning (LEAP); National Impact Analysis (NIA); Bottom-Up Energy Analysis System (BUENAS); Model for Analysis of Energy Demand (MAED); and the Policy Analysis Modelling System (PAMS).

2.2.4 *Multi-Agent Models*

Multi-Agent models are a simulation process that take into consideration market imperfections such as asymmetric information between energy market stakeholders and other non-economic determinants. In this kind of models the agents (i.e. energy market stakeholders) can act in the defined energy system autonomously and interact with other agents as well as the environment. Until recently, multi-agent models were focused on operational aspects rather than long-term planning. The combination of an agent method with a linear optimisation model as a model for planning patterns of the electricity suppliers in a liberalized market has been suggested by Fichtner et al. (2003).

Applications of multi-agent models can be found in the energy converting technologies as well as a lower number in final energy sectors. The main drawback of this kind of models is the huge demand on empirical data in order to accurately forecast the behaviour of each agent. An example of a multi-agent model is the PowerACE, developed for the German electricity market (three main analysis: impact of renewable energy penetration, learning algorithms in price building mechanisms and long-term developments in terms of investment choices in the conventional power sector).

2.3 Comparison of Top-Down and Bottom-Up Energy Modelling

Each energy modelling approach has its advantages and disadvantages. Energy modelling has become an interdisciplinary problem. Therefore, the combination of the macroeconomic as well as the technology detailed approach has become essential. In the following paragraphs, a comparison between the two approaches are presented in order to reach a conclusion about the critical elements that a hybrid model should encompass.

Top-down energy modelling, taking into consideration macroeconomic parameters, has the major advantage of providing the socio-economic effects of energy policy measures on the whole economy of a country or a region. Although, they give a clear image on a macroeconomic level, the absence of technological detail may cause –especially in a long-term horizon- non credible results. Long-term planning must entail technological improvements (or saturation) as well as structural and intra-sectoral alterations. In addition, an attainable market equilibrium which is a basic assumption of top-down models, may not reflect energy's market imperfect competition. Asymmetric information, poor decision making algorithms as well as conflicts among market stakeholders, are the basic sources of market's imperfect competition. Furthermore, top-down models overvalue monetary policies such as subsidies or taxes, as they focus on monetary terms.

On the other hand, bottom-up modelling provides a more accurate representation of the technological standards and details as well as feasible technology futures. A high accuracy of sectoral or technological policy evaluation is a major characteristic of bottom-up models. Despite this fact, a heavy reliance on data as well as on technology deployment assumptions (i.e. investments strategies, O&M assumptions) is arisen. This reliance increases the computational demands of bottom-up models. Finally, the lack of macroeconomic effects on the economic status, employment and prices, from the technology change is one of the major criticism points on bottom-up modelling.

In the next paragraphs, hybrid energy system models which can tackle the limitations of both top-down and bottom-up models are presented.

2.3.1 Hybrid Energy System Models

The basic future of a hybrid energy system model is the merge of at least one macroeconomic model with at least one set of bottom-up models, for each final energy and conversion sector. A concrete hybrid energy system model should entail at least three properties: technological explicitness, micro and macro- economic validity {(Hourcade et al. (2006) and Bataille (2005)}. There are various ways for formulating a hybrid approach regarding energy modelling. The "soft-linking" method is to transfer manually data and coefficients from one type of model to the other and the "hard link" is to use for this transfer automatic routines.
Merging top-down with bottom-up models requires the connection of some model parts (either of top-down or bottom-up) with their modelling counterparts. As Catenazzi (2009) has described, a hybrid energy system model is defined as: "a macroeconomic model with bottom-up energy supply models" and "bottom-up models with some limited macroeconomic sub-models". All in all, these hybrid models have to be accurate and solid keeping the computational cost at normal levels. Yet, the different nature of bottom-up and top-down energy modelling makes the combination of the two models a challenging task.

2.4 Basic structure of various Energy System Models

2.4.1 List of Input Data for various Energy System Models

Many scholars suggest that the main types of models regarding the analysis and the forecasting of an energy system are optimisation (ESOMs) or simulation models. The data required for conducting energy system modeling broadly should contain information regarding the costs and the constraints of technology characteristics [5]. Also, the goal of energy system modelling which can be either cost-minimizing or welfare-maximizing, has to be taken into account by the modeler [11]. The target of an optimisation model is being analyzed in the next section.

Table 2.3: Data input for various energy system models

<table>
<tr><th></th><th colspan="2">Data</th><th>Source</th></tr>
<tr><td rowspan="10">Supply Side</td><td rowspan="4">Commodities</td><td>Fuels</td><td>IEA, YPEN</td></tr>
<tr><td>Energy Carriers</td><td>YPEN</td></tr>
<tr><td>Energy Imports</td><td>YPEN</td></tr>
<tr><td>Emissions</td><td>EEA, DB</td></tr>
<tr><td rowspan="5">Technologies</td><td>Conversion Plants</td><td>YPEN</td></tr>
<tr><td>Refineries</td><td>YPEN</td></tr>
<tr><td>End-use demand (Transportation, Heating etc.)</td><td>YPEN, IOBE, EC</td></tr>
<tr><td>Gas networks</td><td>DESFA</td></tr>
<tr><td>Coal processing</td><td>YPEN</td></tr>
<tr><td>Commodity Flows</td><td>Linking Technologies and Commodities</td><td>YPEN</td></tr>
<tr><td rowspan="7">Demand Side</td><td rowspan="4">Economic Parameters</td><td>GDP growth</td><td>EL.STAT., EC</td></tr>
<tr><td>GVA growth rate</td><td>EL.STAT., EC</td></tr>
<tr><td>Discount Rates (i.e. Cost of Capital or Hurdle Rates) [12]</td><td>IEA, IRENA, Oxera</td></tr>
<tr><td>Elasticities</td><td>EL.STAT., EC</td></tr>
<tr><td>Demographic Parameters</td><td>Population</td><td>EL.STAT.</td></tr>
<tr><td colspan="2">Annual Energy Service Demand in each economic sector</td><td>YPEN, IOBE, EC</td></tr>
<tr><td colspan="2">Annual Electricity and Peak Load demand</td><td>IPTO</td></tr>
</table>

The literature review of various representative energy system models, can be summarized in terms of data input, in the Table 2.3. In this table, the first column contains variables and data that are essential for various models that are namely stated in the second column. The third column contains the source in which each of the data of the first column can be tracked (especially for the Greek Energy System). Due to the vast array of existing energy system models as well as the uniqueness of each examined energy system, the following table is a brief examination of the usual required data input of several energy system models.

The data input of various energy system models can be categorized in those that are related to the supply side of an energy system and those that are relevant to the demand side. In addition, the data input for the technologies of the supply side should contain information regarding the associated costs, the variable costs, taxes, subsidies etc. [9]. Another important factor of each model is the historical data of energy prices. For instance, these prices are those related to the energy imports, fuel pricing and the examined system's marginal price (SMP) amongst others. The time horizon that each model examines also affect the timeline of input data that is required [13].

The aforementioned data input may differ as stated due to the complexity of each energy system that is being modeled. Albeit, Table 1.3 is an attempt of highlighting the basic categories of data input for energy system models.

2.4.2 List of Output Data for various Energy System Models

Taking into consideration the list of inputs of an Energy System Model as well as the constraints of the modeling process, the modeler can define the output of the model. Firstly, it is of great significance that the constraints of a model are properly defined. Constraints may be for instance certain targets in terms of RES penetration in the energy mix or a specific percentage of GHG emissions reduction as well as numerous regulatory and policy guidelines [5].
A literature review in the field of energy modelling can demonstrate the most usual outputs of several energy system models. Some indicative yet representative main outputs of various energy system models are the following ([9], [5], [6]).

- The optimal short or long term energy planning. In other words, the technology mix that satisfies the goal of the modeler (i.e. the goal of the model is linked with the term optimal which are defined in the following section) as well as the defined constraints.
- Operating, equipment, primary energy supply (fuel mix), energy trading (imports-exports of energy) decisions.
- Estimations about CO_2 and other GHG emissions.
- Final Energy use as well as end use technologies. The final energy use term describes for example the economic sectors in which energy will be consumed and the term end use technology refers for instance the type of transportation means or the HVAC equipment via which the energy will be consumed.
- Total energy system's costs. The term energy system cost may be referring to a national, regional or international geographical area or in a specific timeframe. Examples of energy system's costs is the CO_2 emission allowance price or the development of infrastructure.

2.4.3 Criteria of an Energy System modelling approach

The term criteria of an energy system modelling approach refers to the optimal set of outputs that meets the needs of the models. The needs of the modelling approach may be identified and defined in the description of the optimisation and simulation models. Typically the consumer is considered rational and the allocation of the produced energy is being conducted to the energy demanded [5]. By having in terms of constraints, a specific goal or target (e.g.CO_2 reduction target) defined, an optimisation model will forecast the least expensive set of outputs that satisfy the specific set of constraints. In other words, this approach of modelling could be namely described as "least-cost" approach. A "least-cost" approach is being applied in the TIMES model. In macroeconomic terms, TIMES aims at reaching at an equilibrium point where the suppliers produce the quantity demanded by the consumers and more importantly the total surplus is maximized [6].

On the other hand, simulation models are trying to translate the technological and economic reality into feasible yet not cost-effective set of outputs. This leads to the conclusion that this kind of criteria is not representative of models in which one and only decision maker (e.g. a government) aim for example to a "least-cost" set of outputs. Instead, these criteria are more applicable in modelers who represent different market stakeholders and they typically have different goals.

2.5 Summary-conclusions

Different energy system's modelling approaches were examined. The two main approaches, the macroeconomic as well as the techno economic, have both their advantages as well as their disadvantages. Creating a hybrid model may be the solution in order to create a concrete model. Also, the basic structure of various Energy System's models was examined by focusing on the input-output data of these models as well as the criteria that satisfy modelers' needs and goals. This thesis' goal in not the optimization of an entire energy system but the optimization of the power system. To this end, taking into consideration that the Power System is one of the core elements of an energy system, it can be concluded that a power system simulation or optimization model have similar structure and input-output data with those of an energy system model. The main data set required for performing an energy system's modelling study are focused on the supply side –i.e. fuels, emissions, production technologies- and on the demand side –i.e. GDP growth, annual electricity and peak load demand-. Gathering a valid data set is not an easy task as the credibility of the references has to be examined. Thus, the introduction of the main data that are utilized in order to perform an optimization of the Greek Power System are presented in the next Chapter.

3 Data Collection for the Greek Power System modelling

In the following paragraphs, a collection of the required data for the purposes of modelling the Greek Power System is being presented. The time horizon of the modelling is being consisted of a historical data period from 2011 to 2017 and a simulation period beginning from 2018.

Taking into consideration the aforementioned general guidelines and the basic structure of various energy system models, the collection of the appropriate data can be divided into two broad categories. The first is historical and current data which represent technical and financial parameters regarding the available electricity generation technologies, electricity demand data as well as data describing the transmission and distribution of electricity in the power grid. The second category is related to forecasts regarding the evolution of the power system in terms of techno economic assumptions and projections associated with the electricity generation technologies and also electricity demand projections.

3.1 Historical and Current Period's Data

3.1.1 Electricity Demand

A special characteristic of the Greek electricity system is the non-interconnected islands system (NIIs). This system consists of 29 (as of 2017) autonomous island systems, from systems with a peak few tens of kW (e.g. Antikythera island) as well as bigger systems like the one of Crete's island with a peak of around 655 MW. The mainland system has a peak of around 10GW. Therefore for the purposes of modeling the entire Greek electricity system, it is necessary to gather historical data regarding both the mainland system as well as the NIIs. Table 2.1 presents the electricity demand from 2011 up to 2017. The historical data are provided by RAE as part of the annual reports regarding the Greek Energy System that are submitted to EC.

Table 3.1: Electricity Demand in the Greek Energy System (RAE, [14])

	2011	2012	2013	2014	2015	2016	2017
Interconnected system (GWh)	51492	50289	48451	45953	46641	46478	51932
Non-Interconnected system (GWh)	5594	5553	5360	5433	5570	5692	5831
Total Electricity Demand (GWh)	57086	55842	53811	51386	52211	52171	57763

3.1.2 Transmission and Distribution System

3.1.2.a Losses

A crucial parameter regarding the planning of the power system is the estimation of the total losses that the transmission and distribution system will suffer. IPTO records the total losses in the transmission and distribution system. Table 2.2 shows the losses of the transmission and distribution system in absolute values as well as a percentage of the total electricity demand.

Table 3.2: Losses in the Greek Transmission and Distribution System (IPTO, [15])

	2011	2012	2013	2014	2015	2016	2017
Losses [GWh]	1289	1321	1171	1223	1301	1132	1119
Losses as a percentage of Total Electricity Demand [%]	2.26	2.63	2.42	2.66	2.79	2.44	2.15

3.1.2.b Cross Border Interconnections-Imports-Exports

The Greek Electricity System has as of 2017 cross border interconnections with the following countries: Bulgaria, North Macedonia, Albania, Italy and Turkey. Table 2.3 presents the technical characteristics of each interconnection.

Table 3.3: Greece's cross border interconnections transmission capacity as of 2017 (RAE, [14])

Interconnections	**Transmission lines power (kV)**	**Transmission Power Capacity (MW)**	**Transmission Trading Capacity (real) MW ***
Greece-Bulgaria	1 line 400KV	500-600	500
Greece-North Macedonia	2 lines 400kV	2X(500-600)	0-250
Greece-Albania	1 line 400KV	500-800	0-100
	1 line 150 KV	100	0
Greece-Italy	1 line 400KV (HVDC)	500	500
Greece-Turkey	1 line 400kV (HVDC)	500-600	130
*Transmission trading capacity are defined by the TSOs based on real flows (indicated year2012)			

IPTO also provides data on a monthly basis regarding the imports and the exports of electricity across the established cross border interconnections. The following tables present historical data, on a monthly basis, of the imports, exports and the volume of exchange energy (Imports minus Exports).

Table 3.4: Greece's cross border electricity imports from 2011 to 2017 (IPTO, [15])

Cross Border Interconnections-Imports (GWh)							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
January		545	445	497	1249	865	348
February		422	543	392	952	1010	626
March		499	490	755	1249	1112	1041
April		521	469	533	1043	985	1002
May		335	373	682	991	1005	830
June		538	470	746	983	926	751
July		886	537	1068	940	1125	941
August		712	491	1130	1003	1118	762
September		531	450	884	929	919	909
October		428	419	861	725	730	541
November		478	532	1141	587	635	509
December		505	570	1166	715	537	821
Total	**7180**	**5954**	**5788**	**9857**	**11364**	**10967**	**9081**

Table 3.5: Greece's cross border electricity exports from 2011 to 2017 (IPTO, [15])

Cross Border Interconnections-Exports (GWh)							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
January		375	249	42	98	162	281
February		316	396	24	71	45	263
March		371	446	32	50	58	120
April		446	438	94	73	99	158
May		297	229	83	40	92	180
June		267	356	68	71	117	177
July		409	389	73	438	230	250
August		458	346	98	347	206	377
September		382	318	114	210	237	253
October		404	267	172	131	408	285
November		444	238	145	83	210	217
December		449	228	106	153	339	290
Total	**3947**	**4170**	**3900**	**1051**	**1766**	**2204**	**2851**

Table 3.6: Greece's cross border volume of exchange energy from 2011 to 2017

Cross Border Interconnections-Volume of Exchange Energy (Imports-Exports) (GWh)							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
January		171	196	456	1150	703	67
February		107	147	368	881	965	362
March		129	44	723	1199	1054	920
April		75	31	439	970	886	844
May		38	144	599	951	913	650
June		270	114	678	912	808	574
July		477	147	995	501	896	691
August		254	145	1032	656	912	385
September		149	132	770	718	682	656
October		23	152	690	594	322	255
November		33	293	996	504	425	292
December		57	342	1060	562	198	532
Total	**3232**	**1783**	**1888**	**8805**	**9597**	**8762**	**6229**

Table 3.7 provides a useful metric regarding the cross border electricity trading, as it shows both imports and exports as a percentage of total electricity demand.

Table 3.7: Greece's cross border imports-exports as a percentage of total electricity demand from 2011 to 2017

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Average (2011-2017)**
Imports as a percentage of Total Electricity Demand (%)	12.58	10.66	10.76	19.18	21.76	21.02	15.72	**15.95**
Exports as a percentage of Total Electricity Demand (%)	7.30	7.47	7.25	2.05	3.38	4.23	4.94	**5.23**

3.1.3 Power System's Hourly Load

A crucial parameter in the planning and expansion process of a power system is the system's load. Identifying seasonal demand trends in a power system can assist in the planning of a power system's operation. Diagram 2.1 presents the electricity demand in MWh for each hour of year 2017 (8760 hours), where the peak of the electricity demanded is 9368 MWh. In addition, every value from diagram 2.1 is then sorted from the highest to the lowest value and by dividing the sorted values with the peak value, the Load Duration Curve can be derived. The data have been gathered from IPTO's databases.

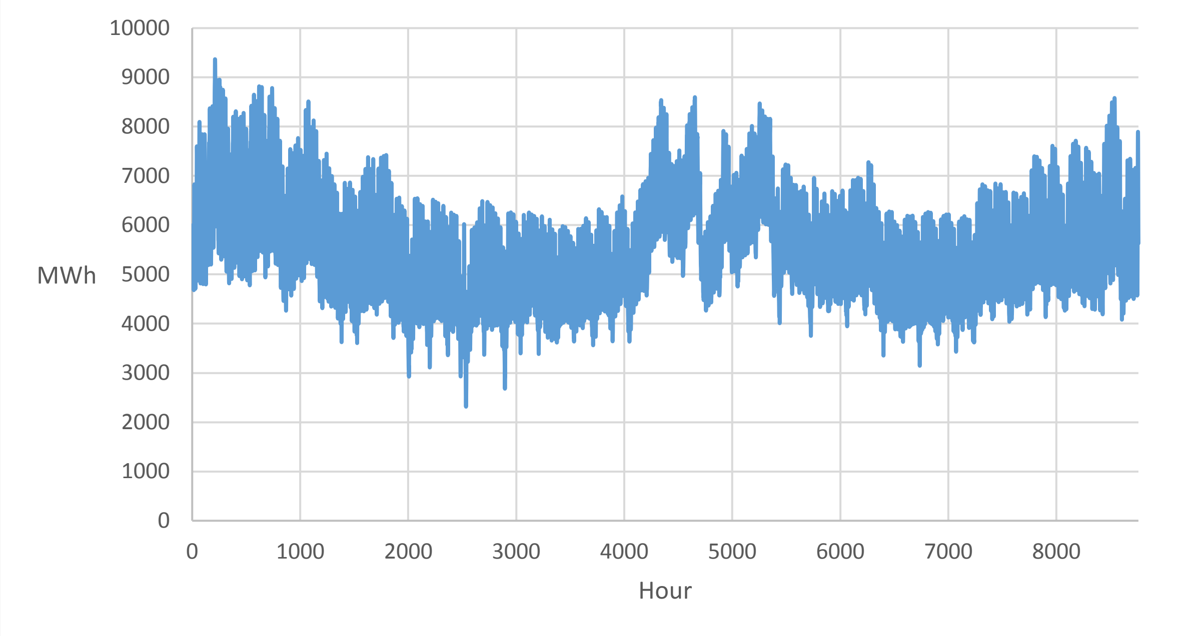


Figure 3.1: Hourly distribution of Greece's electricity demand for 2017 (IPTO, [16]**)**

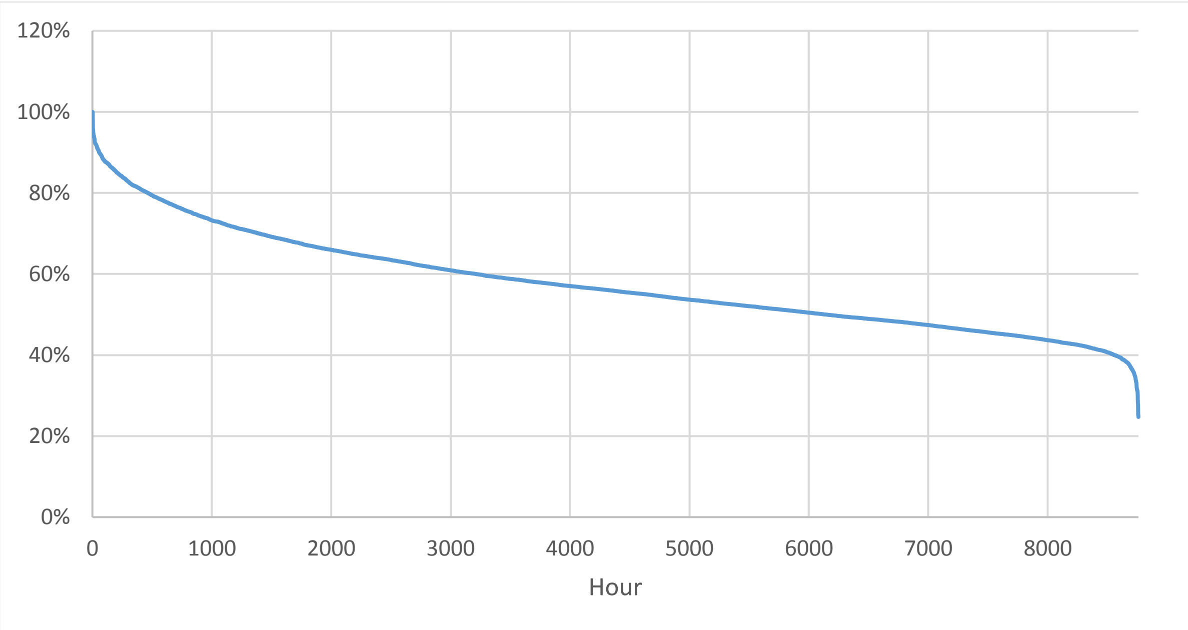


Figure 3.2: Load Duration Curve of 2017 (as a percentage of peak)

3.1.4 Electricity Generation Mix

The electricity generation mix represents the available technologies that are installed in a country and can convert a primary resource into electricity. The main technologies in Greece's electricity generation mix are: Lignite fired thermal plants, Oil combustion thermal plants, Natural Gas plants, Combined Heat and Power Plants (CHP) with natural gas as feedstock fuel, Bioenergy –i.e. Biomass and Biogas-, Large Hydroelectric Plants, Small Hydroelectric plants –with nominal capacity less than 10 MW-, Onshore Wind farms, Photovoltaics and

Photovoltaics installed on buildings roofs. The evolution of Greece's electricity production mix is shown below. The generation mix can be found in RAE's annual reports to EC.

Table 3.8: Greek Electricity Generation Mix from 2011 to 2017 (RAE, [14]**)**

	Greek Electricity Production Mix (MW)						
	2011	2012	2013	2014	2015	2016	2017
Lignite	4456	4448	4456	4456	4462	4337	4337
Oil	2940.6	2940.6	2222.6	2222.6	2222.6	2222.6	2341.9
Natural Gas	4152.8	4153	4573	4906	4642.3	4482.3	4482.3
CHP (Including small cogeneration)	423	416.1	424	334	334	334	334
Biomass&Biogas	44.5	44.8	46	47	52	58	62
Large Hydro	3018	3018	3018	3173	3173	3173	3173
Small Hydro	205	212.9	220	220	224	223	231
Onshore Wind	1363	1465.8	1520	1978	2089	2370	2625
PV	425	1126.1	2070	2221	2229	2229	2230
PV on roof	14	297.8	349	375	376	375	375
Total	**17041.9**	**18123.1**	**18898.6**	**19932.6**	**19803.9**	**19803.9**	**20191.2**

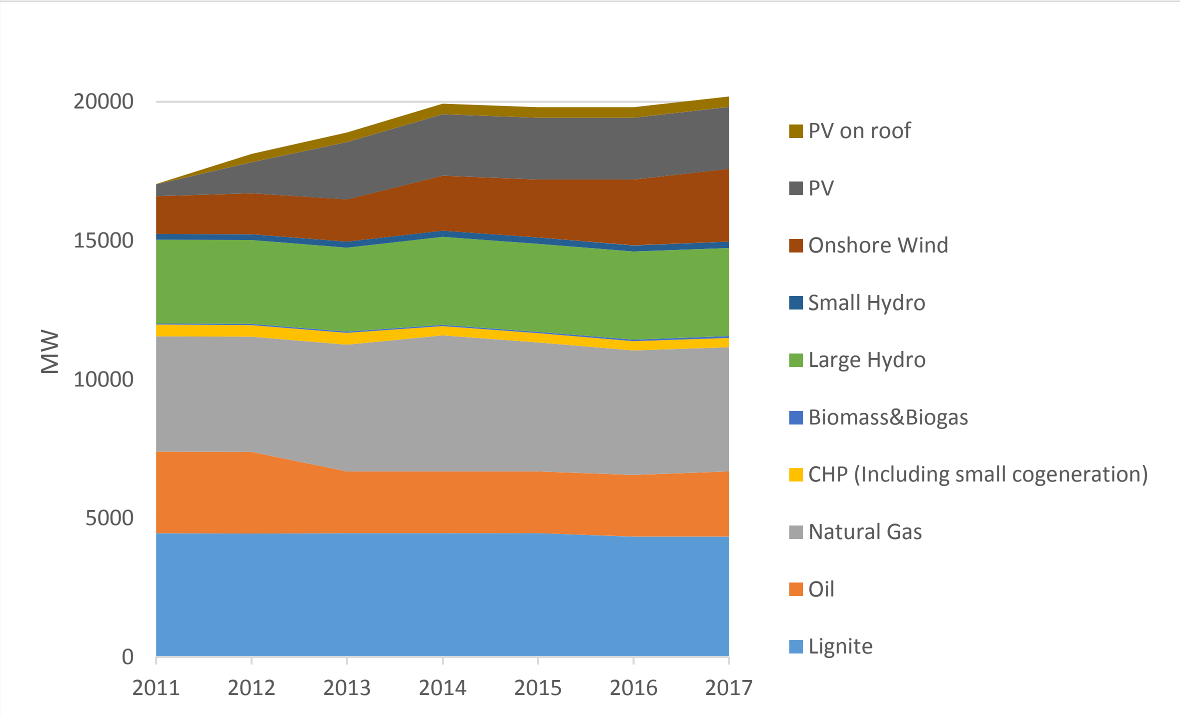


Figure 3.3: Greek Electricity Generation Mix from 2011 to 2017 (MW)

3.1.5 Electricity Production Mix

Taking into account the electricity generation mix as well as the hours that a plant is operating, someone can calculate the electricity production of a specific plant. The historical data regarding the electricity production are presented as follows.

Table 3.9: Electricity Production Mix in Greece from 2011 to 2017 (RAE, [14])

	Electricity Production in Greece (GWh)						
	2011	2012	2013	2014	2015	2016	2017
Lignite	27570	27555	23231	22707	19417	14900	16387
Oil	4768	4697	4458	4520	4633	4735	4799
Natural Gas	13532	13057	10983	6340	7367	12513	15397
CHP (Including small cogeneration)	235	2571	1217	1325	1323	1260	1260
Biomass & Biogas	142	170	210	207	222	253	250
Large Hydro (Including pump storage)	6888	3892	5640	3905	5390	4843	3457
Small Hydro	581	669	771	701	707	722	750
Onshore Wind	2596	3161	3392	3689	4621	5146	5810
PV	371	1231	2929	3322	3409	3418	3697
PV on roof	70	279	457	480	507	494	500
Total Electricity Production	56753	62834	53288	47196	47596	48284	51789

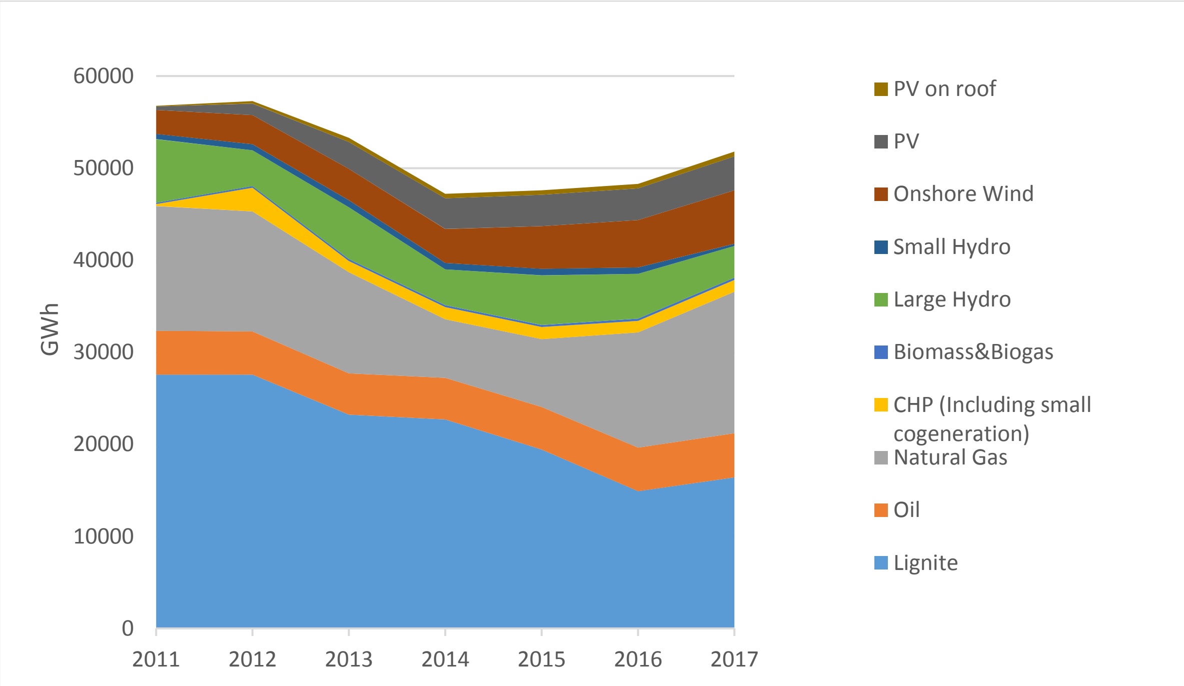


Figure 3.8: Electricity Production in Greece (GWh)

3.1.6 Fossil Fuels Resources

Lignite, natural gas and oil are the fossil fuels that can be tracked in the supply chain of the Greek Power System. Natural Gas and Oil for the purposes of the modelling of the Greek Power System have common characteristics as they are both imported and domestically exploited. The assumption that the plants with feedstock fuel either natural gas or oil will be securely supplied is realistic.

As far as the lignite resources is concerned, the exploitation of lignite mines in Greece has certain limitations. In Greece there are 3.2 billion tons of lignite (or 450 million tons of oil equivalent) that can -under viable techno economic terms- be exploited [17].

3.1.7 Process Efficiency-Capacity Credit-Maximum Capacity Factor-Lifetime

The term process efficiency is the rate of the primary energy (i.e. fuel) that is converted after a generation process (i.e. power plant) into electricity. For the purposes of the current study, the efficiency rates of the RES technologies are equal to 100% as there is no implication with resources depletion. On the other hand, in energy planning studies, process efficiency rates of conventional power plants are of crucial significance as they determine the amount of primary energy that is required for the production of an electricity unit.

Capacity credit can be defined as the ratio of the capacity of an energy plant that is considered firm divided by the rated capacity of this plant. Firm Capacity is the amount of capacity that can be dispatched without decreasing power system's level of credibility. Typically thermal and conventional plants as non-intermittent technologies have capacity credit values equal to 100%. For RES plants this value as a first proxy can be assumed to be equal to plants annual availability.

The maximum capacity factor of the various energy technologies can be defined as the fraction of the maximum electricity that a plant can produce annually divided by the amount of energy that could be produced had the plant operating for 8760 hours per year in its nominal capacity. The maximum capacity factor is determined by the availability of the plant, production curtailments, planned or unplanned maintenance works etc. For the definition of this parameter, in respect to the Greek Power System, historical data regarding the dispatch of the various technologies as well as estimations from the literature have been applied.

Another parameter that is crucial for the energy planning is the lifetime of each plant constituting a certain technology. The term lifetime generally describes not the technically available time a plant can be operating but the available time under the licensing agreement that a plant can be dispatched. It is also important that the decommissioning costs and procedures are taken into consideration at the end of the lifetime of a plant. Typical values of the lifetime of each technology in the Greek market can be found in Table 3.10.

The next table summarizes the four variables for the various energy technologies constituting the Greek Power System (also Geothermal and CSP technologies).

Table 3.10: Technology Characteristics [18]

Technology	Process Efficiency (%)	Maximum Capacity Factor (%)	Capacity Credit (%)	Lifetime (years)
Lignite	35	80	100	45
OCGT	45	75	100	35
CCGT	60	75	100	35
Oil	30	25	100	45
CHP (Including small cogeneration)	55	75	100	30
Biomass & Biogas	48	55	50	30

Technology	Process Efficiency (%)	Maximum Capacity Factor (%)	Capacity Credit (%)	Lifetime (years)
Large Hydro	100	25	100	60
Small Hydro	100	25	20	20
Onshore Wind	100	30	20	20
PVs	100	20	15	20
Geothermal	100	80	30	40
CSP	100	20	25	30

3.1.8 Emission Factors

The typical air pollutants from the combustion process in a thermal plant are namely Nitrogen Oxides, Sulfur Dioxide, Non Methane Volatile Organic Compounds (NMVOC) and Particulates. In order to calculate the total amount of the air pollutants that are emitted someone can apply some emission factors. There are many scholars [19] who suggest that emission factors should incorporate Life-Cycle-Analysis (LCA) methods. Thus, the following table assigns -besides to conventional thermal technologies- to RES technologies emission factors.

Table 3.11: Emission Factors (kg/kWh) [19]

Air Pollutant	Lignite	Natural Gas	Oil	Bio	Hydro	PV	Wind	Geothermal
NMVOC	2.36E-05	1.01E-04	3.45E-05	2.22E-04	1.17E-06	7.09E-05	8.05E-06	0.00E+00
NO_x	7.38E-04	3.09E-04	6.34E-03	1.76E-03	2.36E-05	1.36E-04	3.86E-05	2.00E-05
PPM (2.5-10 μm)	7.61E-05	1.23E-05	1.20E-04	4.86E-05	3.22E-07	4.73E-05	1.17E-05	1.00E-05
PPM (<2.5 μm)	6.47E-05	8.22E-06	0.00E+00	4.25E-05	0.00E+00	2.37E-05	0.00E+00	0.00E+00
SO2	1.69E-04	1.47E-04	6.16E-04	5.31E-04	8.99E-06	2.33E-04	3.83E-05	2.71E-03
CO2	15.77E-01	3.98E-01	6.74E-01	1.80E-02	2.51E-03	5.52E-02	9.56E-03	1.31E-01

As far as the carbon dioxide intensities of the Greek lignite plants, a recent study published on September 2019 [20] suggests that the existing lignite power plants have an average carbon intensity equal to 1.577 kg/kWh. Therefore, the applied CO_2 emission factor for the lignite plants that constitute the Greek Power System is equal to 1.577 kg/kWh.

3.1.9 Cost Data

The cost parameter of the available technologies is of great significance as it can influence investment decisions that consequently affect the evolution of the electricity generation mix. Cost data can be categorized into four categories. The first is the Capital Cost which includes all direct development and construction costs –i.e. overnight costs- as well as any financing cost associated with the development and construction phase of a project.

The second category is the Fixed O&M costs and can be generally characterized as costs that are incurred regardless the amount of energy produced. In this cost category one can identify insurance costs, major maintenance labor expenses, major maintenance spare parts costs, generally planned and long-term maintenance costs etc. The third cost category is the Variable O&M that reflects costs that are associated with each unit of energy produced. The variable O&M costs may include waste and or waste water disposal expenses, chemicals and lubricants, consumable materials and supplies etc.. However, variable O&M costs do not include the fuel costs. Lastly is the Decommission Costs that are occurred at the end of the lifetime of a specific plant [21].

The current cost data are those that have been statistically processed from the various studies that have been used as a reference and reflect the techno economic standards for the year 2017.

3.1.9.a Capital Costs

Capital costs as defined above, can be traced in various international agencies' reviews. In Table 3.12 the current cost data of the various technologies that constitute the Greek electricity generation mix as well as their references are presented. These price values are assumed to reflect the current price levels in Greece for the examined technologies.

Table 3.12: Capital Cost of the available electricity generation mix technologies as of 2017

	Capital Cost		
Technology	**Th. USD/MW**	**Th. €/MW**	**Source**
Lignite	2358	2075	IEA [23]
Oil	500	440	Lazard [24]
Natural Gas	1014	892	Lazard [24]
CHP (Including small cogeneration)	1300	1144	U.S. Energy Department [25]
Biomass & Biogas	1700	1496	Lazard [24]
Large Hydro	-	2000	IEA [23]
Small Hydro	-	2500	IEA [23]
Onshore Wind	1200	1056	Lazard [24]
Offshore Wind	2250	1980	Lazard [24]
PV	-	800	HELAPCO [22]
PV on roof	1900	1672	Lazard [24]
Geothermal	2000	1760	IEA [23]
CSP	3850	3388	IEA [23]
1 USD=0.88 €			

Some technologies such as offshore wind, Geothermal and Concentrated Solar Power have not been installed as of 2017. Regarding PV technology, a recent study [22] suggests that as of 2018 the Capital Costs has been in the vicinity of 650 €/kW.

3.1.9.b Fixed O&M Costs

Regarding the Fixed O&M costs of the various technologies the following data have been gathered from various sources.

Table 3.13: Fixed O&M costs of the available electricity generation mix technologies as of 2017

	Fixed O&M		
Technology	**USD/MW**	**€/MW**	**Source**
Lignite		54301	Green Tank [20]
Oil	10000	8800	Lazard [24]
Natural Gas	6000	5280	Lazard [24]
CHP (Including small cogeneration)	40000	35200	IEA [23]
Biomass & Biogas	50000	44000	Lazard [24]
Large Hydro	45000	39600	IEA [23]
Small Hydro	50000	44000	IEA [23]
Onshore Wind	30000	26400	Lazard [24]
Offshore Wind	80000	70400	Lazard [24]
PV	10000	8800	Lazard [24]
PV on roof	14500	12760	Lazard [24]
Geothermal		66000	IEA [23]
CSP	134320	118201.6	IEA [23]
1 USD=0.88 €			

3.1.9.c Variable O&M Costs

The variable O&M costs reflecting year 2017 are presented in the following table.

Table 3.14: Variable O&M costs of the available electricity generation mix technologies as of 2017

	Variable O&M		
Technology	**USD/MWh**	**€/MWh**	**Source**
Lignite	3.4	2.992	IEA [23]
Oil	10	8.8	Lazard [24]
Natural Gas	2.7	2.376	Lazard [24]
CHP (Including small cogeneration)	-	2	U.S. Energy Department [25]
Biomass & Biogas	10	8.8	Lazard [24]
Large Hydro	0.003	0.00264	IRENA [26]
Small Hydro		0	IEA [16]
Onshore Wind	5.9	5.192	Lazard [17]
Offshore Wind			Lazard [17]
PV	0	0	Lazard [17]
PV on roof	0	0	Lazard [17]
Geothermal	30	26.4	IEA [23]
CSP	0.04	0.0352	IEA [23]
1 USD=0.88 €			

3.1.9.d Decommission Costs

Decommission procedures vary significant due to various factors. Some of these factors can be tracked in the environmental remediation following the decommission of a plant, the location of the plant –i.e. logistics- as well as the residual-salvage value of equipment. To be more specific, as the environmental remediation needs rise, or a plant is located in a remote area, or salvage values are low, the decommission costs are increasing. On the other hand, PVs and onshore wind as they are smaller plants than thermal plants or due to the lack of fuel storage need, tend to have lower decommissioning costs than other plants. Offshore Wind and CSP have higher decommission costs because of the logistical challenges arising from the locations of these kind of plants. Natural Gas and Oil fired plants as the literature indicates tend to have significant varying decommission costs depending on plant's capacity. Lignite fired plants show the highest decommission costs as they are large and old plants and require several environmental remediation works.

Table 3.15 shows indicative decommission costs from various plants in U.S. [21]. CHP plants assumed to have the same decommission costs as the Natural Gas plants. Data regarding Large and Small Hydropower plants are not considered in this thesis as these type of plants is assumed not to be decommissioned in the examined period.

Table 3.15: Decommission costs of the available electricity generation mix technologies

	Decommission Costs	
Technology	**Th. USD/MW**	**Th. €/MW**
Lignite	120	106
Oil	30	26
Natural Gas	15	13
CHP (Including small cogeneration)	15	13
Biomass & Biogas	30	26
Onshore Wind	50	44
Offshore Wind	200	176
PVs	45	40
CSP	100	88
1 USD=0.88 €		

3.1.10 Economic-Social Indicators

Every investment in the Power Sector has various effects in a country's or even a region's economy. An indicator that is applied in this study is the Gross Value Added (GVA). Gross Value Added in economics is a measurement of the contribution to an economy by an individual producer, industry or sector. Then GVA is used in order the Gross Domestic Product of a country to be calculated.

Table 3.9: GVA multipliers as a percentage of CAPEX

Technology	GVA multiplier (% of CAPEX)	Source
Lignite	40%	[27]
Natural Gas	48%	Assumption
CHP (Including small cogeneration)	48%	Assumption
Biomass & Biogas	30%	Assumption
Large Hydro	80%	[28]
Small Hydro	80%	[28]
Onshore Wind	30%	[29]
Offshore Wind	35%	Assumption
PVs	39.60%	[30]
Geothermal	30%	Assumption
CSP	30%	Assumption

In the case of this study, the GVA measurement are derived from the Capital Expenditure of an investment in the Power System. Thus, the calculation of the GVA is the product of a multiplier times the CAPEX of a new Capacity addition. This multiplier is a percentage of the total CAPEX of an annual investment in a certain technology. Table 3.9 presents the multipliers for each technology as a percentage of the total CAPEX.

In addition to the GVA parameter, some other indicators such as total employment are taken into consideration. The impact of an investment in power infrastructure in the employment figures of a country is of great significance and thus it is measured in this study.
The employment effects generated generally by any activity can be categorized into direct, indirect and induced. The direct employment effects in the case of a Power System analysis are those arisen in the various activities of the corresponding plant type and are associated with the development and operation of a plant such as the construction of the power plant, the fuel extraction, the manufacturing of the equipment etc. These activities are executed on local or national level and contribute directly to the level of employment. Also, in order to perform all the aforementioned activities it is imperative to purchase for instance construction materials, equipment and manpower. These additional to the direct expenditures create new jobs in all the sectors of the economy, known as indirect employment effects. All the stakeholders engaged directly or indirectly in the project activities increase their available income and consequently they are increasing their economic consumption. This cycle continues until spending escapes the local/national economy's boundaries, creating new jobs, known as induced employment.

Table 3.17: Employment factors expressed in man-years per TWh of electricity generated

Employment Factors		Lignite	NG	Hydro	Small Hydro	Wind	PV	Biomass-Biogas
Direct	Construction	14.6	4	83.3	83.3	160.3	612.2	116.3
	Operation	104.3	51.3	95.4	95.4	136.9	146.8	363.2
	Fuel extraction & Transportation	119.5	-	-	-	-	-	-
	Total	**238.4**	**55.3**	**178.7**	**178.7**	**297.2**	**759**	**479.5**
Indirect	Construction	9	2.5	39.5	39.5	88.2	333.7	57
	Operation	19.8	9.7	40.2	40.2	61.6	56.4	130.8
	Fuel extraction & Transportation	39.3	-	-	-	-	-	-
	Total	**68.1**	**12.2**	**79.7**	**79.7**	**149.8**	**390.1**	**187.8**
Induced	Construction	4.5	1.2	31.5	31.5	66.3	255.6	45
	Operation	54.2	26.6	54.1	54.1	74.7	98	136.5
	Fuel extraction & Transportation	84.8	-	-	-	-	-	-
	Total	**143.5**	**27.8**	**85.6**	**85.6**	**141**	**353.6**	**181.5**

The quantification of the employment effects for the various technologies constituting the Greek Power System have been conducted from scholars such as ([31], [32]) and are presented in the following table. These effects are being classified in three categories as mentioned before, the direct, indirect and induced employment for the construction, operation and fuel extraction

activities for each technology of the Greek Power System. The values of the employment factors of Table 3.17 are in man-years per TWh of electricity generated.
Another important social indicator introduced in this study is associated with the work safety in the electricity sector. There are estimations from various studies such as ([33], [34]) indicating the worker injuries as well as the severe accident fatalities per unit of electricity produced. The following table presents these factors.

Table 3.18: Estimations regarding work safety indicators for the Greek Power System

	Lignite	NG	Hydro	Small Hydro	Wind	PV	Biomass-Biogas
Total number of worker injuries (no. of injuries/TWh)	4.5	0.54	1.68	1.68	3.01	4.85	2.78
Number of fatalities per TWh of electricity produced (no. of fatalities/TWh)	0.0207	0.0051	0.0003	0.0003	0	0.0011	0.0017

Due to lack of available data regarding the social indicators of CHP, CSP, Offshore and Geothermal technologies it is assumed that CHP and CSP, Onshore and Offshore Wind and Biomass-Biogas and Geothermal have the same social indicators.

3.2 Projections regarding the evolution of the Greek Power System

3.2.1 Electricity Demand Projections

IPTO delivered in 2018 the 10-year development of the Greek Power and Transmission system. In this context, IPTO developed three demand scenarios for the interconnected system covering the period 2018-2028. IPTO suggests that in these projections the level of elasticity of the electricity demand in response to changes of the Greek GDP is not significant. Furthermore, IPTO assumes that as of 2018 the majority of the islands in Cyclades will be fully interconnected and also Crete beginning from the second semester of 2020 and ending in 2024. In Table 3.19 table the three demand scenarios for the interconnected system are presented. For the period 2029-2040 a regression has been applied based on the 2018-2028 demand values.

Table 3.19: IPTO's demand scenarios (IPTO, [35]**)**

	Electricity Demand Scenarios [GWh]		
	Low	**Reference**	**Extreme**
2018	53100	53400	53490
2019	53500	54310	54630
2020	54800	55840	56400
2021	56040	57325	58120
2022	56270	57750	58750
2023	56510	58180	59375
2024	58375	60250	61730
2025	58670	60740	62440
2026	58960	61230	63150
2027	59250	61730	63880
2028	59550	62230	64610
2029	60917	63871	66478

	Electricity Demand Scenarios [GWh]		
	Low	**Reference**	**Extreme**
2030	61599	64774	67609
2031	62282	65677	68741
2032	62965	66580	69873
2033	63647	67483	71004
2034	64330	68386	72136
2035	65013	69289	73267
2036	65695	70192	74399
2037	66378	71095	75530
2038	67061	71998	76662
2039	67743	72901	77793
2040	68426	73804	78925

3.2.2 *Emission Constraints & Externality Costs*

Greece, being a MS of the European Union, has to meet specific targets regarding GHG emission reduction. For each MS, the GHG emission target can be converted into annual emission constraints. Part of Greece's commitments to EU that will be implemented under the directive 2016/2284/EC are presented in the following table [36].

Table 3.20: Greece's national targets for reduction of specific air pollutants

	Percentage of Reduction compared to 2005	
Air Pollutant	**Period 2020-2029**	**2030**
Sulfur Dioxide (SO_2)	31%	55%
Nitrogen Oxide (NO_X)	54%	62%
Non-Methane Volatile Organic Compound (NMVOC)	74%	88%
Ammonia (NH3)	7%	10%
Suspended Particulate Matter (<2.5 μm)	35%	50%

From available data from OECD Libraries the level of air pollutants for the base year of 2005 are presented in the following table.

Table 3.21: Greece's 2005 air pollutants emissions (OECD, [37])

Air Pollutant	2005 emissions [thousand tonnes]
Sulfur Dioxide (SO_2)	391.95
Nitrogen Oxide (NO_X)	140.51
Non-Methane Volatile Organic Compound (NMVOC)	1.8
Suspended Particulate Matter (<2.5 μm)	14.57

As far as CO_2 emissions, there are specific national targets that set constraints in the overall power sector. More specifically the Greek Ministry of Energy in November 2018 published a draft on a long term energy planning for Greece, which is called “National Plan for the Climate and Energy for 2030”. This plan revised on January 2019, states that Greece will reduce its CO_2 emissions in the power sector by 45% in 2030 compared to 2016. In 2016 the total CO_2 from the power sector amounted to 36.91 Million tonnes [38]. Therefore, Greece has set a CO_2 emission constraint for 2030 regarding the power sector equal to 20.3 Million tonnes. The assumptions regarding the future allowance prices projections are presented as follows.

Table 3.22: CO_2 allowance prices projections (EC, [39])

CO_2 Prices (EUR/ton CO_2)				
2020	**2025**	**2030**	**2035**	**2040**
15	22.5	33.5	42	50

In every electricity generation mix scenario there are various harmful effects such as environmental pollution. Some scholars suggest that electricity production affects soil, noise, visibility, global climate, human health and visual amenity. Typical air pollutants that have major impact in these areas are the following: particulate matter (PM), ozone (O3), carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), lead (Pb), volatile organic compounds (VOCs) and polycyclic aromatic hydrocarbons (PAHs). The environmental consequences of electricity production can be modelled with the external costs of electricity production, i.e. monetary value of damages. These costs are imposed on society (e.g. human health) and the environment (e.g. crops, forests etc.) and generally are not accounted by the production side nor the consumption side of electricity production.

Table 3.23: Externality Costs for the technologies of the Greek Power System [19]

Technology	Total (€/kWh)
Lignite	1.45E-02
Natural Gas	6.29E-03
Oil	5.38E-02
Biomass	1.75E-02
Hydropower	2.47E-04
PVs	3.64E-03
Wind	6.22E-04
Geothermal	1.94E-02

Studies such as [40] have made estimations regarding the impact type of the examined technologies such as Health, Biodiversity, Crop yield, Material damage and Climate Change. These externality costs are expressed in (€/kWh) and are imposed as monetary values per amount of energy produced. Table 3.23 presents these externality costs for the various technologies of the Greek Power System. It is assumed that these costs will remain constant in the future (modelling years).

3.2.3 *Fuel Prices*

The main fuel that can be found in the Greek power system are lignite, natural gas, oil (diesel) and biomass.

The lignite fired power plants utilize the domestic lignite mines. Therefore, the assumption of a constant price of lignite can be made based on the fact that these type of plants have long-term contracts with the lignite mines' operators. A review delivered to PPC which is publicly available [41] suggests that the total lignite cost is equal to 14.82 €/ton.

As far as oil and natural gas prices, IEA suggests in its review [42] the following international price projections.

Table 3.24: International fuel prices projectionσ

		2020	2030	2040
Natural Gas	$/Mbtu	7.1	10.3	11.54
Oil	$/bbl	79	111	124

Biomass cost as IRENA [26] suggests for the year 2017 is equal to 2.25 $/GJ. Based on the complexity of biomass supply chain and the uncertainty regarding fuel prices, we can assume that this price will remain constant in the future.

3.2.4 *Integration-Retirement of Conventional Power Plants*

The evolution of the power system as well as future investments in new RES plants depends heavily on the scheduled integration or retirement of conventional thermal units. IPTO's power adequacy study for the period of 2017-2027 describes a scheduled pathway for commissioning and decommissioning of conventional thermal units.

Table 3.25: Integration/Retirement of Lignite Power Plants (IPTO, [35])

	Integration/Retirement of Lignite Power Plants							
Year	**2018**	**2019**	**2020**		**2021**	**2022**	**2023**	**2025**
Capacity Addition	-115	-629	-546	-18	660	-378	-1102	-255
Plant	Agios Dimitrios	Agios Dimitrios	Amyntaio I&II	Agios Dimitrios V	Ptolemaida V	Agios Dimitrios	Kardia I-IV	Megalopoli III
Lignite Capacity (MW)	4222	3593	3029		3689	3311	2209	1954

In Table 3.25 (a positive sign indicates the commission of a new plant and a negative the decommission) commissions and decommissions of lignite fired power plants are presented. Some assumptions have been made regarding the time schedule of the proposed integrations/retirements due to the fact that significant delays in the development phase of some projects have been occurred.

As far as the Natural Gas plants in Greece is concerned the IPTO's power adequacy planning reports that in 2018 a new 811 MW natural gas combined cycle will be added to the Greek Power System. This plant is located in Megalopoli and the development of the project is undertaken by PPC. The total installed capacity of the natural gas plants in Greece as of 2018 is 5293.3 MW.

There are also some projects being developed by private companies that have received production licenses (or will receive). These projects have total capacity in the vicinity of 3500 MW. The following table presents these projects in terms of total installed capacity as well as the expected – assumed delivery dates. Yet, these projects may not be integrated in the power system as various licenses and procedures are pending.

Table 3.26: Potential Natural Gas fired plants additions in the Greek Power System [43]

Production Licenses requests submitted to RAE		
Investor	**Capacity**	**Region**
Mytilineos Group	825	Agios Nikolas, Voiotia
Kopelouzos Group	660	Alexandoupoli
Elpedison	826	Thessaloniki
GEK Terna	660	Komotini
KEN	665	Larissa
Total	**3636**	

However recent announcements suggest that as of approximately 2022 the Agios Nikolas plant in Voiotia will be fully operational and will be dispatched in the Greek Interconnected System. Besides conventional thermal plants, a hydro-pump plant is under development in Amfiloxia. The developer is GEK Terna and the total capacity of the plant will be 680 MW. The construction phase of this project is expected to start in 2019 and the anticipated delivery year of the project is 2023.

3.2.5 Decommissioning of RES Plants

The lifetime of each plant of a certain technology affects the generation mix as the decommissioning of power plants decreases the available capacity that can be dispatched. Regarding conventional thermal plants, the decommissioning timeline has been described in Section 2.2.4..

Table 3.27: Decommissioning of PVs & Onshore Wind Plants (MW)

Year of Retirement	PV	PV on Roof	Onshore Wind
2018	-	-	11.5
2019	-	-	67.7
2020	-	-	128.3
2021	-	-	41.8
2022	-	-	16.3
2023	-	-	115.7
2024	-	-	72.2
2025	-	-	122.4
2026	-	-	146.4
2027	2	-	100.6
2028	10	-	146.5
2029	35	-	158.6
2030	152	-	165.8
2031	418.9	6.1	313.0
2032	628.2	283.8	113.0
2033	991.8	51.2	115.0
2034	-	26	112.0
2035	-	1	159.0
2036	6.0	-	233.0
2037	13.0	-	282.0

On the other hand, RES plants –especially PVs and Onshore Wind plants- that have been commissioned prior and during the historical period (2011-2017) need to be considered in terms of decommissioning process. Public available data from ELETAEN [44] and the Hellenic Association of Photovoltaic Companies [22] regarding the period prior to 2017, provide an image about the decommissioning timeline of onshore wind and PV plants. Table 3.27 presents the planned decommissions of PV and Onshore Wind plants that will be occurred in the examined scenario period. As far as the Large and Small Hydro plants is concerned it is assumed that at least for the examined period there is no decommissioning concern.

3.2.6 Cost Projections

There are various available reports in the literature that attempt to track global price trends in the electricity production technologies. Although these reports track global trends, in the case of this study it can be useful to apply these trends in the current market prices of Greece so as to forecast future Greek market prices.

3.2.6.a Capital Costs

In Annexe I, data from a report from the German Institute for Economic Research (DIW Berlin) [45] were utilized in order to calculate annualized percentage rates of capital cost reduction for the available technologies. The following table summarizes the annualized rate of reduction of the capital costs, derived from a 5-year interval cost values. The calculated rates that correspond to conventional thermal plants are split to those that will install carbon capture technologies (w CC) or not.

Table 3.28: Annualized Percentage Rate of Capital Cost reduction.

		2015-2020	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
Lignite	w CC	-0.27%	-0.25%	-0.26%	-0.25%	-0.25%	-0.24%	-0.24%
	w/o CC	0%	0%	0%	0%	0%	0%	0%
Oil	w CC	0%	0%	0%	0%	0%	0%	0%
Natural Gas & CHP	w CC	-0.25%	-0.22%	-0.22%	-0.22%	-0.21%	-0.21%	-0.22%
	w/o CC	0%	0%	0%	0%	0%	0%	0%
Biomass & Biogas		-0.61%	-0.61%	-0.62%	-0.61%	-0.61%	-0.62%	-0.61%
Large Hydro		0%	0%	0%	0%	0%	0%	0%
Small Hydro		0%	0%	0%	0%	0%	0%	0%
Onshore Wind		-0.46%	-0.48%	-0.46%	-0.47%	-0.47%	-0.46%	-0.47%
Offshore Wind		-0.88%	-0.88%	-0.88%	-0.88%	-0.88%	-0.88%	-0.88%
PV		-4.21%	-2.00%	-2.22%	-1.50%	-2.99%	-1.02%	-1.03%
PV on roof		-4.21%	-2.00%	-2.22%	-1.50%	-2.99%	-1.02%	-1.03%

The Capital Costs presented in Annex 10.1, as monetary values, are all expressed in the same reference year (i.e. 2010 in the report from DIW). Therefore, the Capital Cost projections, in the case of the Greek Power System, are expressed in 2017's monetary values. The capital costs regarding the Greek Power System are presented in Annex 10.1.2.

3.2.6.b Fixed O&M Costs

It is assumed that the Fixed O&M costs will remain constant for the examined scenario period.

3.2.6.c Variable O&M Costs

It is assumed that the Variable O&M costs will remain constant for the examined scenario period.

3.2.6.d Repowering Costs

As far as the decommissioning process of RES plants –especially onshore wind and PVs- is concerned, there is an alternative besides the complete disposal of the plant. Repowering is a term meaning the installation of a new electromechanical equipment (e.g. a new wind turbine or a new photovoltaic panel). In this case, it can be assumed that the Repowering Cost is capital cost occurring in a particular year and covers the aforementioned type of equipment. Data regarding the various costs of a RES plant [26] can provide an approximation of the repowering costs. Therefore, for an onshore wind farm the Repowering cost is equal to the 75% of the total Capital Cost and for PVs equal to 50%.

3.3 Summary-conclusions

In this Chapter the main data regarding historical-current as well as projections regarding key figures of the Greek Power System were presented. All of these data can be used either as input data in a power system model or as factors for the calculation of certain sizes (e.g. emissions, employment impact etc.). All the presented data are being imported firstly in a model and secondly in the simplified model that is being constructed in order to forecast the evolution of the Greek Power System.

4 Modelling Approaches

A concrete model of the Greek Power System shall incorporate all the information-data gathered and presented in Chapter 2. The first step in modelling the Greek Power System's expansion is to select a modelling approach. As mentioned in Chapter 1.4.3 there are two main modelling approaches: the optimisation or the simulation. For the purposes of this study an optimisation approach is being applied. In addition, the examined period of the scenarios is considered to be from 2018 to 2040.

The term optimization of the expansion of the Greek Power System can be translated for instance into finding the "least-cost" mix of technologies that both satisfy specific constraints as well as minimizing the overall costs of the power system. Many studies apply this methodology (i.e. the "National Plan for Climate and Energy).

Initially, the optimization of the expansion of the Greek Power System is being performed with an open-access commercial computational package. Literature review has been conducted by the writer ([46], [13]) in order to determine the characteristics of open-access as well as commercial models that can be used as computational tools for modelling the Greek Power System's expansion. The purpose of this preliminary modeling with an open-access and accredited computational package is one the one hand to investigate the functionality of these models and on the other to compare a commercial model with the one that is being created for the purposes of this diploma thesis. Also, the data required by a commercial program determine the reliability of the selected by the writer data that are imported in the simplified model. Therefore, comparing the output data of an accredited computational package with those of the model that is being created is of great significance.

4.1 LEAP modelling

To this end, the Long-Range Energy Alternatives Planning (LEAP) has been selected. LEAP is an integrated modelling tool, supported currently by the Stockholm Environment Institute, and can analyze national as well as regional energy-systems. It can apply several of different modelling approaches on the demand-side such as a bottom-up, end-use accounting techniques as well as top-down macroeconomic. On the supply side, LEAP applies accounting and simulation techniques as well as optimisation modelling. LEAP contains a scenario manager where the user defines "storylines" regarding policy measures as well as other pathways for the future evolution of the energy system. Amongst others. LEAP calculates and returns as results the electricity generation and production mix, the actual capacity factor of the technologies constituting the production mix, overall electricity production and investment costs as well the GHG emissions from the power system.

LEAP's optimization approach is a "least-cost" one. In LEAP, optimization can be used to calculate the least-cost expansion and dispatch of power plants for a power system, where optimal is defined as the power system with the lowest total net present value of the social costs of the system over the entire period of calculation (from the base year through to the end year). LEAP defines as social costs the capital costs for building new plants, the decommissioning costs, the fixed and variable O&M costs, the fuel costs as well the environmental externality costs.

In LEAP, a least cost power system can optionally be calculated subject to a number of user specified constraints including maximum annual levels of emissions for any given pollutant (CO_2, SO_x, NO_x, PM_{10} etc.) and minimum or maximum capacities for certain plant types. For example, an expansion pathway for an energy system could be calculated that met a minimum renewable portfolio standard (RPS) whilst also staying within a target for reducing greenhouse gas (GHG) emission.

LEAP's input data for the optimization module are now being presented. Firstly, the user introduces data on annual emission limits as well as externality costs. The user then determines the evolution of electricity demand. It also introduces the percentage of losses in the transmission and distribution system as a percentage of the energy produced, the electricity imports and exports target. Then the user introduces the annual System's Electricity Load Shape, which determines the peaks of electricity demanded (see Section 3.1.3.) as well as a Planning Reserve Margin (the difference of the system's total capacity from the peak load as a percentage of the peak load). The user can also define for a specific year a renewable target which is the percentage of energy produced by technologies which are characterizes as RES.

Then, data regarding the characteristics of each technology constituting the generation mix are introduced. For the historical-current period, the evolution of the generation and production mix is defined by the user. The Maximum Availability, the Capacity Credit, the Capital Costs, the Fixed and Variable O&M costs, the decommission costs, the lifetime and interest rate are also introduced by the user. For the scenario period, the user must define the Maximum and Minimum Capacity in each year for every technology as well the Maximum and Minimum Capacity Additions. These variables are only utilized in the optimization module (not in the simulation module). Lastly, the user introduces data regarding the resources of each fuel (e.g. lignite, natural gas, biomass etc.).

Some of the output data of LEAP are: the evolution of the generation and production mix, the Capacity Additions, the Peak Power Requirements, the overall Social Costs (i.e. the production Costs) and the volume of emissions [47].

LEAP's optimization module uses the GNU Linear Programming Kit (GLPK), a software toolkit intended for solving large scale linear programming problems by means of revised simplex method.

In the following section, the simplified model as well as the proposed optimization approaches are introduced.

4.2 Simplified Power System Expansion Model

The construction of a simplified power system expansion model is now being presented. This is an optimization model having specific constraints, input data as well as decision variables. The core of this optimisation model is the objective function. The four different optimization approaches that have been developed are being presented in the following sections.

4.2.1 Mathematical Formulation

4.2.1.a Total Annualized Production Cost Minimization

A recent study [48] suggests some economic indicators that are used in order to describe the sustainability of the expansion of the Greek interconnected system. One of these economic indicators that can be used as an objective function in an optimisation method is the Total Annualised Production Cost of electricity system. The formula of the Total Annualised Production Cost (TAPC) of the electricity system is the following:

$$TAPC_i^z\left(\frac{€}{year}\right) = Capacity_i^z(MW) * [CapitalCost_i^z\left(\frac{€}{MW}\right) * AF_i + FixedO\&M_i^z\left(\frac{\frac{€}{MW}}{year}\right)] + Capacity_i^z(MW) * CF_i^z(\%) * 8760h * [VariableO\&M_i^z\left(\frac{\frac{€}{MWh}}{year}\right) + FuelCost_i^z\left(\frac{\frac{€}{MWh}}{year}\right) + ExternalitiesCost_i\left(\frac{\frac{€}{MWh}}{year}\right) + EF_i^z\left(\frac{tonnesCO_2}{MWh}\right) * CC_i^z\left(\frac{\frac{€}{tonnesCO_2}}{year}\right)] \quad \textbf{(4.2-1)}$$

where

- *i* is an indicator of technology and z the year of calculation.
- $Capacity_i^z$ is the capacity in (MW) of the technologies that constitute the Greek interconnected system
- $CapitalCost_i^z$ in (€/MW) the capital cost for introducing a new plant from the *i* technology
- $FixedO\&M_i^z$ in (€/MW/year) and $VariableO\&M_i^z$ in (€/MWh/year) the fixed and variable operation and maintenance cost of the *i* technology respectively
- $ExternalitiesCost_i$ in (€/MWh/year) the externalities cost of each technology that constitutes the Greek interconnected system
- $CF_i^z(\%)$ the capacity factor of the *i* technology
- $FuelCost_i^z$ in (€/MW/h/year) the cost of the fuel that is used for operating a plant from the *i* technology
- EF_i^z is the CO_2 emission factor in ($tonnesCO_2$/MWh)
- CC_i^z is the cost of emitting CO_2 on an annual basis in (€/$tonnesCO_2$) of the
- AF_i is an annuity factor in order to annualize the capital costs. The annuity factor can be computed as follows:

$$AF_i = \frac{r*(1+r)^{t_i}}{(1+r)^{t_i}-1} \quad \textbf{(4.2-2)}$$

where

- t_i is the lifetime of the *i* technology and *r* the discount rate (cost of capital).

The calculations in the TAPC formula provide an approximation in (€/year) of the total annualized production costs of the interconnected electricity system.

The first optimisation approach tries to minimize this objective function –i.e. the TAPC formula- by having specific decision variables, inputs and constraints.

Firstly, the definition of the decision variables of the optimisation process is essential. As the TAPC formula suggests, the variable that drives the cost is the installed capacity of each technology that constitutes the generation mix. Consequently, the capacity values of each technology are be designated as decision variables of the optimisation model.

In addition, the Capacity Factor is a crucial parameter that affects both the production mix as well as the variable O&M, the fuel, the externalities and the CO_2 costs. Also, the total electricity production is affected by the electricity imports policy. Imports from the established interconnections affect the dispatch of the available technologies of the generation mix.

The optimization process is being conducted for two cases. The first case is the annual optimization. In this case, decision variables are the capacity values of each technology as well as the Capacity Factors and the percentage of imports. Each objective function is being optimized on an annual basis.

The second case, is an optimization covering a 3-year period. In this case, the sum of the Total Annualized Production Cost (3) for a 3-year period is being optimized by having as decision variables the capacity values and the percentage of annual imports of every year examined. This method is a moving one which means that beginning from 2018 the first 3-year period of optimization is 2018-2020 and the next one is 2019-2020.

The Capacity Factors for each technology, for the entire scenario period (i.e. 2018 to 2040) are being received as inputs by the optimization process. The values of the Capacity Factors are the ones that have been calculated by the first case of optimization (i.e. annual optimization). Therefore, the second case provides an optimized mix of technologies taking into consideration 3-year collection of data.

The expansion of a power system and the impact of the proposed additions/retirements are often examined not for a single year but for a longer time horizon. The reason for choosing to optimize on a three-year horizon is that when you consider a longer time horizon in optimization, the allocation of new capacity additions/retirements is optimally distributed.

The first constraint of the optimisation process is that the total electricity production of every technology plus the total electricity imports to be equal to the projected demand.

Also, a minimum and a maximum value regarding the Capacity Factor of each technology are constraints of this model. These constraints (a range for the Capacity Factor) are assumptions based on the historical data. These values are also address issues regarding the stability of the grid (i.e. capacity credit).

The next constraints of the optimization approach are the Maximum and Minimum Capacity as well as the Maximum and Minimum Capacity Additions for each technology.

Overall, the next formulas present the objective function, the decision variables as well as the constraints of the first optimization approach which is the minimization of formula (1), for the two different cases.

1-year optimization:

- *Decision Variables (25 variables)*

$$Capacity_i^z, CF_i^z, Imports^z$$

- *Objective function*

$$OF_{c1} = \sum_{i=0}^{n} TAPC_i^z \quad \textbf{(4.2-3)}$$

- *Constraints (75 constraints)*
  - $minCapacity_i^z \leq Capacity_i^z \leq maxCapacity_i^z$ **(4.2-4)**
  - $\min(\Delta C) \leq Capacity_i^{z+1} - Capacity_i^z \leq \max(\Delta C)$ **(4.2-5)**
  - $minCF_i \leq CF_i^z \leq maxCF_i$ **(4.2-6)**
  - $Imports^z(GWh) + [1 - TDL(\%)] * Total\ Electricity\ Production^z(GWh) = Projected\ Demand^Z(GWh)$ **(4.2-7)**
  - $minImports(\%) \leq Imports^z(\%) \leq maxImports(\%)$ **(4.2-8)**

3-year optimization:

- *Decision Variables (39 variables)*

$$Capacity_i^z, Imports^z$$

- *Objective function*

$$OF_{C2} = \sum_{z=1}^{3} \sum_{i=1}^{n} TAPC_i^z \quad \textbf{(4.2-9)}$$

- *Constraints (225 constraints)*
  - $minCapacity_i^z \leq Capacity_i^z \leq maxCapacity_i^z$ **(4.2-10)**
  - $\min(\Delta C) \leq Capacity_i^{z+1} - Capacity_i^z \leq \max(\Delta C)$ **(4.2-11)**
  - $minCF_i \leq CF_i^z \leq maxCF_i$ **(4.2-12)**
  - $Imports_i^z(GWh) + [1 - TDL(\%)] * Total\ Electricity\ Production^z(GWh) = Projected\ Demand^Z(GWh)$ **(4.2-13)**
  - $minImports(\%) \leq Imports^z(\%) \leq maxImports(\%)$ **(4.2-14)**

where
- *i* are the available technologies and n is the total number of the available technologies
- *z* the index of the year of calculation
- $\min(\Delta C)$ and $\max(\Delta C)$ the minimum and maximum capacity additions respectively
- CF_i^z the annual Capacity Factor for the *i* technology
- $minCF_i$ and $maxCF_i$ the minimum and maximum Capacity Factor of the *i* technology
- $Imports^z(\%)$ the annual percentage of electricity imports in respect to the total electricity demanded

- TDL is the Transmission and Distribution System's losses as a percentage of the total electricity demand
- $minImports(\%)$ and $maxImports(\%)$ the minimum and maximum import share (%), as a percentage of the projected electricity demand

The decision variables and the constraints in the 3-year optimization approach are applied for every year (not a single one). For instance, from 2018-2020 the decision variables are the capacity values and the annual imports share for all these years.

4.2.1.b Investments Maximization

Besides the TAPC formula, there are various economic indicators that can be used as an objective function of the optimisation process. The first economic indicator is the Total Investments. An investment in a power technology, on an annual basis, can be calculated by multiplying the Capital Cost of each technology with the Capacity Addition, occurred in this year. If the Capacity Addition is positive, then an investment activity is occurring.

$$Investment_i^z = \begin{cases} \left(Capacity_i^z - Capacity_i^{z-1}\right) * CapitalCost_i^z & Capacity_i^z - Capacity_i^{z-1} > 0 \\ 0 & Capacity_i^z - Capacity_i^{z-1} \leq 0 \end{cases}$$

(4.2-15)

As mentioned before this approach attempts to maximize the total investment activity. The economic result of an investment is being calculated, for the purposes of this thesis, in real values not in discounted.

The optimization is being performed in two cases (annual and 3-year). The constraints and decision variables are the same with the ones of the TAPC minimization approach. Therefore the objective functions in the two cases are the following.

1-year optimization:

- *Objective function*

$$OF_{c3} = \sum_{i=0}^{n} Investment_i^z \qquad \textbf{(4.2-16)}$$

3-year optimization:

- *Objective function*

$$OF_{C4} = \sum_{z=1}^{3} \sum_{i=1}^{n} Investment_i^z \qquad \textbf{(4.2-17)}$$

4.2.1.c Value Added Maximization

Similarly to the maximization of the Total Investments, the Value Added maximization can be applied as an optimization approach. Using the multipliers presented in Section 3.1.10 an approximation of the total Value Added in the Greek Economy that is generated by an investment, can be calculated. Only this component of Value Added is considered

The GVA for every investment in a new plant of the technology *i* in a year *z* can be calculated by the following formula.

$$GVA_i^z = \begin{cases} Investment_i^z * GVAm_i & Investment_i^z > 0 \\ 0 & Investment_i^z = 0 \end{cases} \quad \textbf{(4.2-18)}$$

where

- $GVAm_i$ is the multiplier in order to calculate the GVA (see Section 3.1.10) for the *i* technology.

As in the investments maximization approach, the monetary values in this equation are expressed in real values, not in discounted.

Having the same constraints and decision variables as the ones for the TAC minimization and Investments maximization approaches, the objective functions for the two cases are the following.

1-year optimization:

- *Objective function*

$$OF_{C5} = \sum_{i=0}^{n} GVA_i^z \quad \textbf{(4.2-19)}$$

3-year optimization:

- *Objective function*

$$OF_{C6} = \sum_{z=1}^{3} \sum_{i=1}^{n} GVA_i^z \quad \textbf{(4.2-20)}$$

4.2.1.d Monetary Outflows Minimization

The last proposed optimization approach is the one for calculating the Monetary Outflows from the operation and the development of the Power System.

The Monetary Outflows of the electricity system is defined as follows:

$$Monetary\ Outflows^z \left(\frac{€}{year}\right) = TNGFC^z \left(\frac{€}{year}\right) + \sum_i^n Investment_i^z \left(\frac{€}{year}\right) * (1 - GVAm_i) + ElectricityImportsCost^z \left(\frac{€}{year}\right) \quad \textbf{(4.2-21)}$$

Where

- $TNGFC^z$ stands for the Total Natural Gas Fuel Cost in (€/year)
- $GVAm_i$ is the multiplier regarding the Value Added to the Greek Economy
- $ElectricityImportsCost^z$ (€/year) is the cost of electricity imports occurred in one year.

The *NGFC* can be calculated by multiplying the projected natural gas price with the electricity produced by natural gas fired plants. Also, the $ElectricityImportsCost^z$ can be calculated using an electricity imports price of Greece's cross border electricity trading. This price is then multiplied with the amount of electricity demand that is satisfied by imports.

The formulas for calculating the $NGFC^z$ and $ElectricityImportsCost^z$ are the following ones.

$$TNGFC^z\left(\frac{€}{year}\right) = \{[CF^z * Capacity^z]_{i=NaturalGas} + [CF^z * Capacity^z]_{i=CHP}\} * 8760h * NGFC^z\left(\frac{€}{MWh}\right) \quad \textbf{(4.2-22)}$$

where the brackets contain the electricity produced by the Natural Gas Stations and the CHP plants multiplied by $NGFC^z\left(\frac{€}{MWh}\right)$ which is the fuel cost for natural gas for the year *z*.

$$ElectricityImportsCost^z\left(\frac{€}{year}\right) = Imports^z(\%) * ProjectedDemand(GWh) * ELP(\frac{€}{MWh}) \quad \textbf{(4.2-23)}$$

where $ELP(\frac{€}{MWh})$ is the cost for importing electricity from the established interconnections.

Due to lack of estimations about the evolution of the electricity imports price, it is assumed that for the entire examined period it will be equal to 40 €/MWh.

The sum of the total natural gas fuel cost plus the electricity imports cost are called from now on as ISEIC which stands for Interconnected System's Energy Imports Costs.

$$ISEIC\left(\frac{€}{year}\right) = TNGFC^z\left(\frac{€}{year}\right) + ElectricityImportsCost^z\left(\frac{€}{year}\right) \quad \textbf{(4.2-24)}$$

In this optimization approach the constraints and decision variables are the same as in the previous approaches. For the Monetary Outflows minimization approach, the objective function for the two cases (annual and 3-year optimization) are presented as follows.

1-year optimization:

- *Objective function*

$$OF_{c7} = Monetary\ Outflows^z \quad \textbf{(4.2-25)}$$

3-year optimization:

- *Objective function*

$$OF_{c8} = \sum_{z=1}^{3} Monetary\ Outflows^z \quad \textbf{(4.2-26)}$$

The inputs of these optimization approaches are the Lifetime of each technology, the Capital, Fixed and Variable O&M costs, the Fuel Costs (i.e. for Lignite and Natural Gas fired plants), projections regarding the future CO_2 prices, the projected electricity demand, the CO_2 emissions factors as well as 2017's generation and production mix.

4.2.2 Computational Package

The aforementioned inputs, constraints as well as the objective function were modelled in Microsoft Excel software, using Visual Basic for annual simulations. Excel's solver was applied for the optimisation calculations. The annual optimisation approach is a nonlinear problem as the total electricity production contains the product of two different set of decision variables (capacity values and capacity factor values). The solving method that is being applied is the "Generalized Reduced Gradient Nonlinear" ("GRG Nonlinear") solver. This solver calculates the gradient of the objective function as the input values (or the decision values) change and determines that there is an optimal solution when the partial derivatives are equal to zero. A drawback of this solver is the high dependence on the initial conditions. This means that the solver may terminate the process at the local –and not the global- optimum value that satisfies the initial conditions of the problem.

In the 3-year optimization case, the solver that is being applied is the Simplex for Linear Problems. In this case the problem is a linear one as the decision variables are the Capacity Values and the percentage of electricity imports and there is no a product or a power in the objective function that could raise issues of linearity.

It should be noted that computational limitations of Excel's solver in handling nonlinear problems (200 decision variables and 100 constraints) and in linear problems (200 decision variables) did not allowed the inclusion of decision variables (i.e. capacity values, capacity factors, annual electricity imports shares) for the entire period (i.e. 2018-2040). Thus, for the purposes of this study, the examined period has been designated to be a 3-year one.

4.3 Comparison of LEAP and Simplified Model

At this point it is worth comparing LEAP with the model that is being developed in this thesis. First of all, it is essential to compare the input data, the constraints as well as the objective function of each model. The comparison focus on the required data of each model that determine and affect the functionality and the nature of optimization of each model. It is important to state that LEAP's objective function is not publicly available in terms of equations etc.

In terms of inputs and constraints, the common input data between LEAP and the simplified model are the following ones:

- Electricity Demand Projections
- Meeting Electricity Demanded (Imports + System's Production = Demand)
- Cost Data (Capital Costs, Fixed and Variable O&M, Fuel Costs, Lifetime of each technology)
- Transmission and Distribution Losses
- Minimum, Maximum Capacity Additions and Total Capacity of each Technology
- Externality Costs and CO_2 Prices

LEAP's objective function which is the minimization of the total social costs for the entire period has some similarities with the TAPC minimization approach as formula's (3) definition is similar to LEAP's social costs description. However, LEAP does not optimize in terms of maximization of investments or minimization of monetary outflows.

The simplified model developed for the purposes of this thesis does not take into account a number of variables describing the power system in more details, taken into account by LEAP. Such variables are: hourly power system's load distribution, planning reserve margin, capacity credit values, imports-exports target, exports of electricity, efficiency rates of each production technology, the environmental emissions from every technology available (the simplified model in the calculation of TAPC formula takes into consideration only the CO_2 emissions), annual emission constraints, discounted monetary values and the evolution of the electricity imports prices.

On the other hand, in the simplified model the definition of a lower and upper threshold in the Capacity Factor, is a major difference between the two models. In LEAP, the user defines the Maximum Availability of each technology (which is similar to the Maximum Capacity Factor) but does not define a minimum value of availability or a minimum value of each technology's Capacity Factor. In addition, in LEAP the installed capacity of RES plants (onshore wind and PVs) is not repowered as it is happening in the simplified model.

In the next chapter a preliminary comparison between LEAP's and simplified model's results is being presented so as to assess the simplified model's functionality and therefore to proceed with the presentation of the results and outcomes of the model.

4.4 Summary-conclusions

In this chapter, an accredited model as well as the model that is being developed in this thesis were presented. The presentation of the basic input data as well as the purpose of each model took place. The basic structure, the required input data as well as the 4 different optimization approaches were presented in this chapter. In the following pages, the examined scenarios as well as the underlying assumptions regarding the expansion of the Greek Power System are presented.

5 Greek Power System Expansion Scenarios

In this chapter, the examined scenarios regarding the Greek Power System expansion are presented. Four different scenarios are examined. All scenarios refer to the interconnected system.

The first one is a reference scenario that takes into account the standard projections regarding the evolution of the Greek Power System. The second one is the one where different electricity demand scenarios are examined and the role of Natural Gas Stations is being investigated. The third one is a scenario where Offshore Wind farms will be integrated in the interconnected system. The fourth scenario examines the 100% decommission of lignite plants from the Greek Power System.For the Reference Scenario, the data set of Chapter 3 is being introduced into LEAP's optimization module as well as in the Simplified Model, so as a first validation of the functionality of the simplified model to be presented. The data set that is being introduced is the one regarding cost data, emission factors and constraints, fuel prices and data form Section 3.1.7.. The additional assumptions required by each model are presented in the following sections.

5.1 Reference (REF) Scenario

5.1.1 LEAP modelling

The optimization module of LEAP requires as a first step the introduction of the electricity demand of the power system as a whole. In the REF scenario, the interconnected system is being examined and the demand projections of IPTO are applied. Thus, the oil-fired plants that are dispatched in the non-interconnected island are being ignored. The evolution of demand as it is inserted in LEAP is being presented in the following figure.

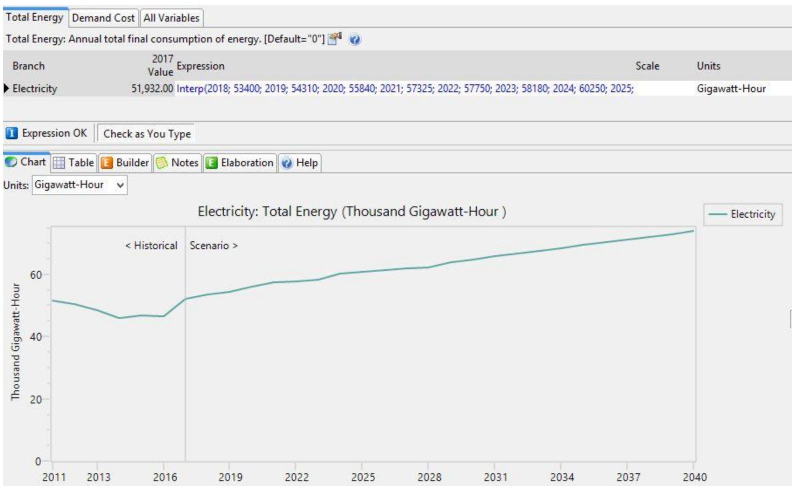
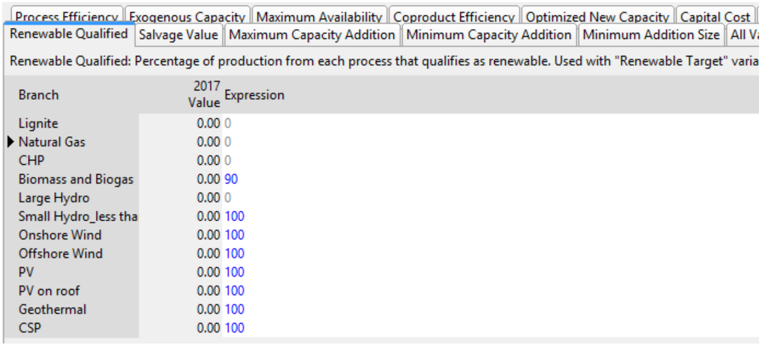


Figure 5.1: User's Interface in LEAP- Electricity Demand Evolution

The definition the planning reserve margin is required in LEAP. This variable indicates the percentage of the excess system's capacity in respect to the peak load. The reserve margin is a crucial parameter for the operator of the system. For this scenario, this variable is set to be equal to 15%.

LEAP's optimization module requires the definition of a renewable target variable, a constraint indicating the minimum percentage share of technologies that are designated as renewable in the production mix. The small hydropower, the onshore and offshore wind, the photovoltaics, the geothermal and CSP are designated as 100% renewable technologies and the biomass-biogas as 90%. For the case of this scenario, this variable is set to 0% as the renewables that are being introduced in the generation mix need to reflect future techno economic standards as well as future market conditions of the electricity system. Therefore, an output of this scenario is the share of the technologies marked as renewables in the production mix.

The next figure shows the renewable qualification as it is inserted by the user in LEAP.



Branch	2017 Value	Expression
Lignite	0.00	0
Natural Gas	0.00	0
CHP	0.00	0
Biomass and Biogas	0.00	90
Large Hydro	0.00	0
Small Hydro_less tha	0.00	100
Onshore Wind	0.00	100
Offshore Wind	0.00	100
PV	0.00	100
PV on roof	0.00	100
Geothermal	0.00	100
CSP	0.00	100

Figure 5.2: User's Interface in LEAP- Renewable Qualification

In addition, based on the historical data regarding imports and exports of electricity from the established interconnections, the Import Target and Export Target variables can be approximated as an average of the historical values. These variables in general reduce the power that the system has to dispatch in order to meet demand requirements as they satisfy part of the demand before the domestic plants are dispatched. For this scenario, an approximation of 10% and 5% of the total electricity demand of the interconnected system for the Import Target and Export Target variables respectively are applied.

As far as the domestic technologies that are introduced in an expansion scenario the following variables have great impact and significance. These variables are the Maximum and Minimum Capacity and the Minimum-Maximum Capacity Addition variables. The Maximum Capacity variable sets an upper threshold in the overall capacity of a technology in each examined year.

The Minimum Capacity Addition sets the minimum capacity that can be added in a particular year and on the other hand the Maximum Capacity Addition the maximum capacity that can be introduced in a particular year.

The definition of these variables-constraints introduces to the model extra uncertainties as – especially for the additions variables- these variables try to capture the future market conditions that will create the framework for potential investments in new plants. In this scenario the Minimum Capacity Addition variable is to 0 (the default value of LEAP's optimization module). The definition of the Maximum-Minimum Capacity of each technology is being presented in the next section.

As far as the Maximum Capacity Addition variable is concerned, the main issue that is arising is the definition of this variable for the RES technologies. For the Lignite fired plants, section 3.2.4 eliminates the need for defining the Maximum Capacity Addition variable, as there will not take place additional additions except the ones defined in this section.

In order to reflect the future market conditions that will provide an approximation for defining the Maximum Capacity Addition variable for the RES technologies some assumptions are made based on relevant information from other studies or assumptions.

For the PV technologies, a report from Hellenic Association of Photovoltaic Companies [22] indicates that for 2018, 2019 and 2020 capacity additions will be at the vicinity of 50 MW, 150 MW and 250 MW respectively. Therefore for the years 2018-2020 these numbers are assigned to the Maximum Capacity Addition variable and from 2020 onwards 300 MW are assigned. The assumption from 2020 onwards can be characterised as feasible and realistic as the on-going reduction in the capital costs of PVs will probably accelerate new investments in PV plants. For PVs installed in rooftops a 5 MW value is assumed.

Onshore wind technology from 2011 to 2017 had an average annual capacity addition of approximately 190 MW (with lowest value 112 MW in 2014 and highest 313 MW in 2011) [44]. In the transition to a low carbon economy, onshore wind energy will play a crucial role in the production mix and therefore a value in the vicinity of 300 MW as Maximum Capacity Addition variable for onshore wind energy is being assumed. Offshore wind technology is currently in Greece in an immature phase in terms of licensing procedures and therefore is not considered in the REF scenario.

For the rest of RES technologies, it is assumed for Biomass & Biogas, for Small Hydropower and for CSP the values of 50,15 and 50 MW as Maximum Capacity Addition values.

The next figure shows the input data that the user inserts in LEAP regarding the maximum capacity addition variable.

Figure 5.3: User's Interface in LEAP- Maximum Capacity Additions Variable

The Minimum Capacity Addition variable is of great significance mainly for RES technologies as the higher penetration of those in the power system should be quantified and established. Therefore, it is assumed taking into consideration any available market forecasts for each RES technology a minimum level of capacity addition. For Biomass & Biogas, Small Hydro, Onshore Wind, PVs and PVs on roof, the Minimum Capacity Addition variable is equal to 10, 5, 150, 200 –from 2020 onwards-, 1, 20 respectively.

As far as the CSP technology is concerned, a project in Crete in the vicinity of 50MW is expected to be in construction phase in 2019 [49]. Therefore, it is assumed that in 2024 (the forecasted year of completion of Crete's interconnection) 50MW of CSP technology will be added in the interconnected system. Also it is assumed a maximum capacity of CSP technology in the vicinity of 100 MW with a maximum capacity addition value of 50 MW. On the other hand, for Geothermal technology being an immature technology in the Greek Interconnected system, it is assumed that a Maximum Capacity value in the vicinity of 100MW as well as a maximum capacity addition on an annual basis of 20 MW –beginning from 2030- are realistic values.

All the aforementioned variables and their assigned values are presented in the form of table in the next section.

5.1.2 Simplified Power System Expansion Model

The Maximum Capacity and the Minimum-Maximum Capacity Additions of each technology have the same values as the ones that are defined in LEAP. For the simplified model developed in this thesis, the additional required parameters are defined in the following paragraphs.

For the REF scenario the discount rate is set to be equal to 5%. Also, it is assumed that cost of emitting CO_2 is being incurred only for Lignite and Natural Gas fired plants.

Therefore, the CO_2 emission factors from section 3.1.8. and the CO_2 prices from section 3.2.2. (using a linear regression in order to calculate annual CO_2 prices) are applied.

In the REF scenario a typical value of 2% for *TDL* is being selected.

For the *ElectricityImports* variable a range of 5% to 25% is set as a constraint.

The inputs of these optimization approaches are the Lifetime of each technology (see Section 3.1.7), the Capital, Fixed and Variable O&M costs (see Sections 3.1.9 and 3.2.5), the Fuel Costs (i.e. for Lignite and Natural Gas fired plants), the Externality Costs (see Section 3.2.2.), projections regarding the future CO_2 prices, the projected electricity demand, the CO_2 emissions factors (see Section 3.1.8.) as well as 2017's production and generation mix.

The Capacity Factor –after reviewing the historical period data- varies for each technology as the production mix changes from each year, despite any capacity additions. This means that a range for this variable has to be defined as mentioned in Chapter 4. For convergence issues of the optimisation process, this range should not be wide.

Table 5.1: Constraints values of Optimisation approaches-Capacities & CF

Technology	Minimum Capacity [MW]	Maximum Capacity [MW]	Maximum Capacity Addition [MW]	Minimum Capacity Addition [MW]	Minimum CF (%)	Maximum CF (%)
Lignite	1300	5000	0	-200	50%	71%
Natural Gas	4400	8000	1000	-200	20%	40%
CHP	334	1000	100	0	68%	71%
Biomass and Biogas	62	300	20	10	36%	52%
Large Hydro	3100	4000	0	0	15%	26%
Small Hydro_less than 10MW	250	450	15	5	32%	40%
Onshore Wind	2650	7500	250	150	20%	25%
Offshore Wind	-	-	-	-	25%	30%
PV	2000	8500	300	200	18%	20%
PV on roof	300	1000	5	1	18%	20%
Geothermal	0	100	20	0	70%	90%
CSP	50	100	50	20	15%	20%

Table 5.1 summarizes the additional to Chapter 3 data set that is being introduced in both LEAP and in the simplified model so as to reflect the future techno economic and market conditions. The values presented in Table 5.1. are assumptions based on historical data and refer to annual values.

At this point a results' comparison between the TAPC minimization approach for both annual and 3-year case, LEAP's optimization module and the proposals of "National Plan for Energy and Climate" (ESEK) are being presented. The results to be taken into consideration are the ones for the evolution of the generation and production mix. This comparison serves validation purposes regarding the functionality of the simplified model developed in this thesis. In the simplified model and LEAP, the capital cost data as well as the electricity demanded (for the interconnected system) defined in ESEK's results were introduced for comparison reasons.

The following figures present the evolution of the installed capacity and the electricity production for selected technologies.

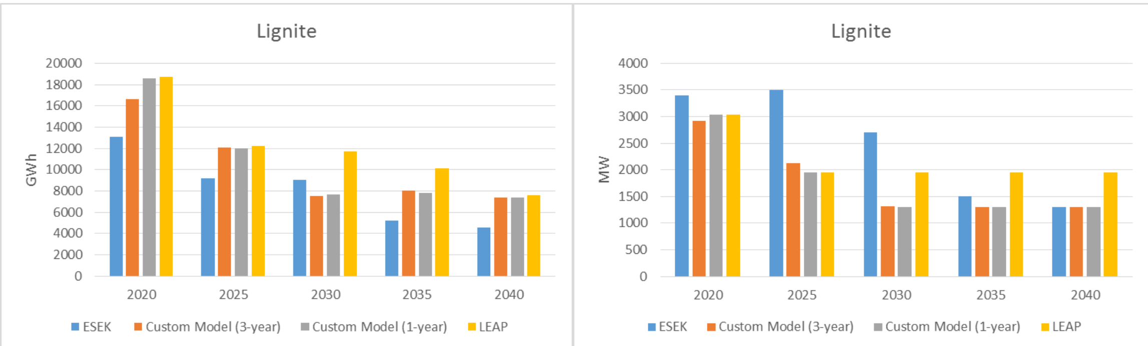


Figure 5.4: Comparison of Lignite Generation and Production Mix – ESEK, Simplified Model, LEAP

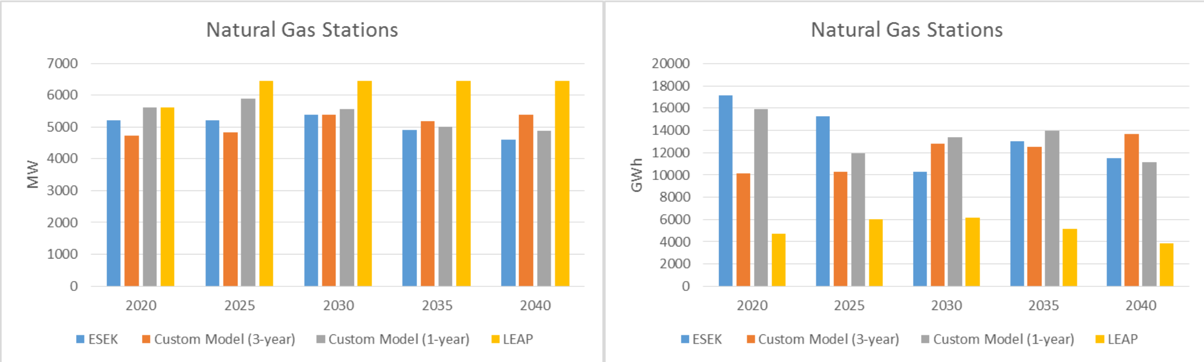


Figure 5.5: Comparison of Natural Gas Stations Generation and Production Mix – ESEK, Simplified Model, LEAP

Figure 5.6: Comparison of Hydropower Plants Generation and Production Mix – ESEK, Simplified Model, LEAP

Figure 5.7: Comparison of Onshore Wind Farms Generation and Production Mix – ESEK, Simplified Model, LEAP

Figure 5.8: Comparison of PVs Generation and Production Mix – ESEK, Simplified Model, LEAP

The above figures are a first estimate of the credibility of the designed simplified model. In RES technologies, there is quite good convergence with both the results of the LEAP and the results of the ESEK, both in terms of installed capacity as well as in electricity production (except the onshore wind production in ESEK where it is higher than the other results). Regarding the installed capacity of the natural gas stations. Between the simplified model and ESEK there is a convergence. On the other hand, LEAP does not add new Natural Gas Stations after 2025. Significant convergence exists between the ESEK and the simplified model regarding the electricity produced in the Natural Gas Stations. LEAP keeps in low levels the electricity produced in Natural Gas Stations. Lastly, both the simplified model as well as LEAP reduces in a higher rate than ESEK, the Lignite installed Capacity. However, the simplified model and LEAP keep the electricity production from Lignite plants at higher levels.

As a conclusion, it can be stated that the simplified model that is being developed has a quite good convergence with LEAP. The results of ESEK's are generally in line with those that the simplified model generates, for the same input data.

5.2 Alternative Demand Scenarios-The role of Natural Gas Stations

In this section, in addition to the reference demand scenario, the expansion of the Greek Power System as well as the role of the Natural Gas Stations, in a Low and in an Extreme Demand Scenario is being investigated. The Demand Scenarios are the ones that have been presented in Section 3.2.1.

The capacity additions of RES technologies have less flexibility than those of a thermal station due to the current and future market conditions of RES technologies. Therefore, especially for the Extreme Demand Scenario the Maximum Capacity value of the Natural Gas technology is increased to 10,000 MW as the rest of the available technologies, being less flexible in terms of capacity addition cannot be added in higher rates. The input data regarding the constraints are the ones defined for the REF scenario.

The optimization approach that is being applied is the TAPC minimization. The results from the various demand scenarios are presented in the next chapter.

5.3 Penetration of Offshore Wind Technology

This scenario will investigate the penetration of offshore wind projects in the interconnected system. Greece has a great wind energy potential in the Aegean Sea but various limitations such as the steep sea-bed drop-off around mainland Greece and around the Aegean Islands, offshore wind costs and various environmental and military restrictions, have made the deployment of offshore wind farms a challenging issue. However, some offshore wind projects have managed to obtain an Electricity Production license from RAE. For instance, the first project is an offshore wind farm near Alexandroupolis in Thrace in the vicinity of 216MW and the second one is in the vicinity of 500 MW near Limnos Island in northern the region of the Aegean Sea [43].

Assuming that the aforementioned limitations will be overcome, the year of deployment for these projects can be assumed. Therefore, in this scenario it is assumed that as of 2025 these two projects totaling 716 MW will be integrated in the interconnected system. This is an estimation of the size of the first offshore wind projects that will be integrated in the interconnected system.

In addition, from year 2025 and onwards, the potential for new offshore wind projects will be securely considered. In this case, it is assumed that for offshore wind projects the Maximum Annual Capacity Addition variable will be in the vicinity of 50 MW from year 2026 onwards. Also, the Maximum Capacity for offshore wind technology is assumed in the vicinity of 1000MW. The rest of the input data in this scenario are the same as the ones in the REF scenario.

Overall, in this scenario the optimization approach that is being applied is the TAPC minimization, in a 3-year optimization case. The penetration of offshore wind technology is being examined for IPTO's reference demand scenario and a comparison between this scenario's results and REF scenario's results is also presented.

5.4 100% Decommission of Lignite Power Plants

Decommissioning lignite power plants is a major and controversial issue in Greece. The transition in a more green generation mix is imperative. In this scenario the 100% decommission of Lignite Power Plants is being examined. Thus, the Minimum Capacity value of Lignite technology in the model is set to 0. The rest of the input data in this scenario are the same as the one in the REF scenario.

A recent announcement from the Greek Government (September 2019) stated that as of 2028 the Greek Generation Mix will have no Lignite Power Plants. Therefore, in the current scenario the 100% decommissioning of Lignite Power Plants in 2028 is being investigated. This alternative pathway for lignite power plants in the Greek Power System is being examined in the reference and in the extreme demand scenario (See Section 3.2.1).

The decommission of lignite power plants is being investigated for IPTO's reference and extreme demand scenarios (See Section 3.2.1.). The optimization method that is applied is the TAPC minimization one in a 3-year optimization case. A comparison between the results of the different demand scenarios for the REF scenario and the results from this scenario are presented.

5.5 Summary-conclusions

In Chapter 5, the four scenarios that are examined in this thesis were presented. The definition of certain assumptions regarding the simplified model and LEAP was conducted. Also, a preliminary comparison between the simplified model, LEAP and ESEK's results was made, proving that the simplified power system expansion model, developed in this thesis, can perform reliable calculations regarding the optimization of the Greek Power System's expansion. The next chapter presents the results and findings of the simplified model for each examined scenario.

6 Sample Analysis Results using the Simplified Model

The results of the optimisation process performed with the Simplified Power System Expansion Model are presented in this chapter.

Amongst the various results, in this chapter the Electricity Generation Mix (Installed Capacity), the Production Mix, the percentage of the electricity produced by RES technologies (i.e. RES Share), the Total Annualized Production Cost, the Levelized Cost of Electricity produced (LCOE), the Total Annual and Cumulative (i.e. for the period 2018-2040) Investments, Value Added and Monetary Outflows (€), the Interconnected System's Energy Import Costs (ISEIC), the annual direct, indirect and induced employment effects, the annual and cumulative injuries and fatalities and the emissions (focus on CO_2) are presented. In every scenario, a comparison between the optimization approaches and cases (annual and 3-year) will be conducted.

6.1 Reference (REF) Scenario

For the REF scenario in every figure of the aforementioned variables there are two bars, one for the annual optimisation and one for the 3-year optimisation (see Section 4.1.2). This is a first step for comparing the two cases of optimization. A comparative analysis is also being conducted. The analysis of the results presented in the previous section has as a goal the comparison of the two optimization (i.e. one year optimization or 3-year optimization) cases as well as the evaluation of the main indicators under different optimization goals (i.e. TAC minimization or Investments Maximization etc.).

In the following figures, the first bar is for the annual optimisation case and the second one for the 3-year optimisation case.

6.1.1 Electricity Generation Mix (Installed Capacity)

The electricity generation mix (installed capacity) for each optimization approach is presented in the following figures, for the two optimization cases (annual and 3-year).

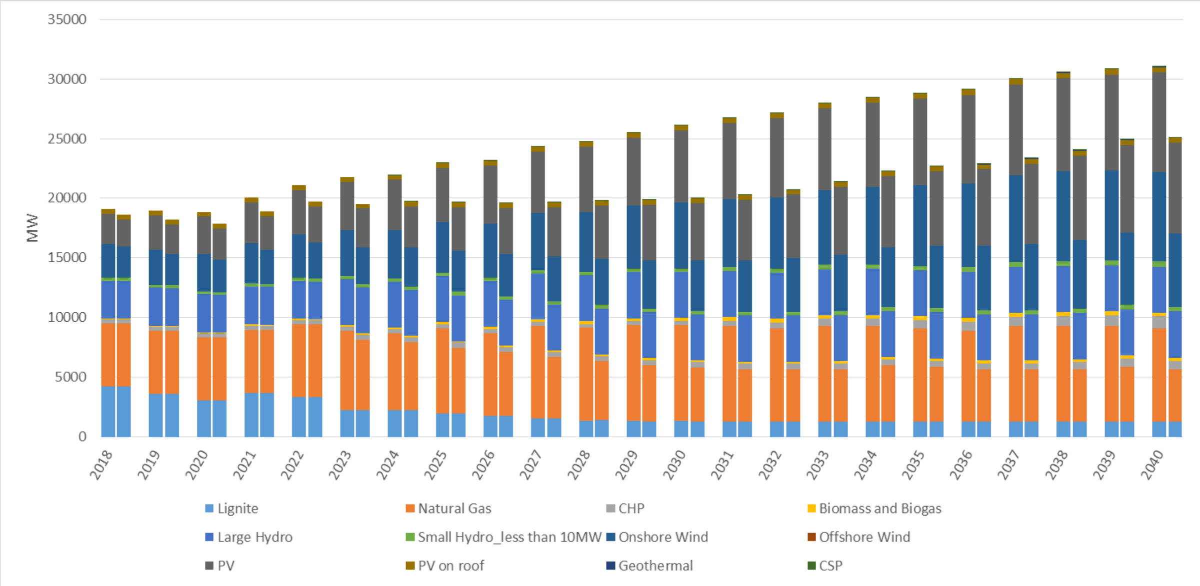


Figure 6.1: Evolution of the Greek Electricity Generation Mix - TAPC Minimization Approach

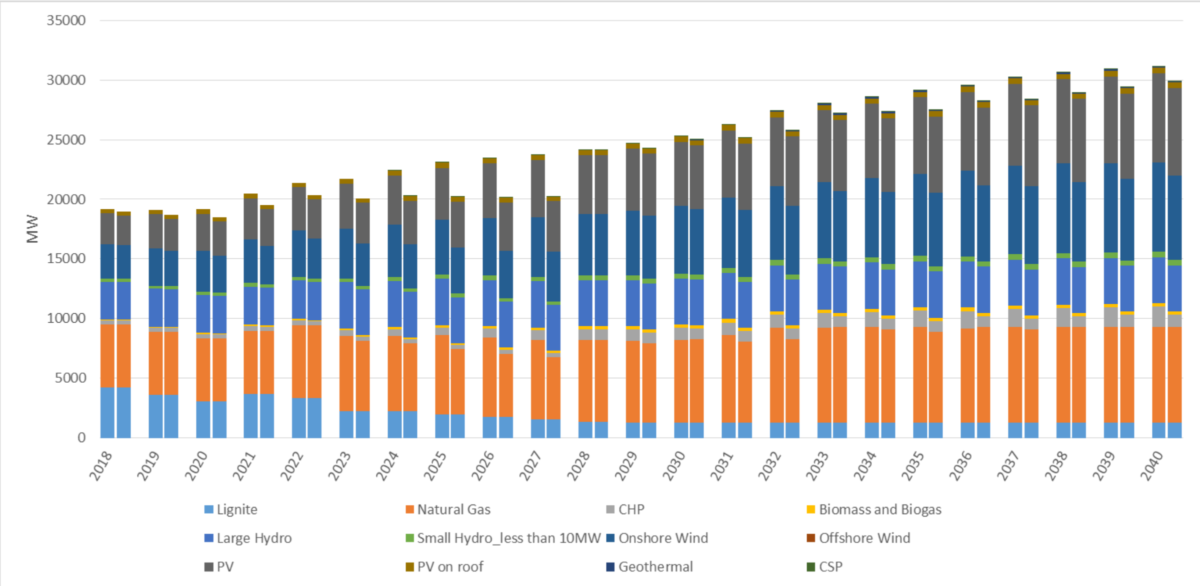


Figure 6.2: Evolution of the Greek Electricity Generation Mix -Investments Maximization Approach

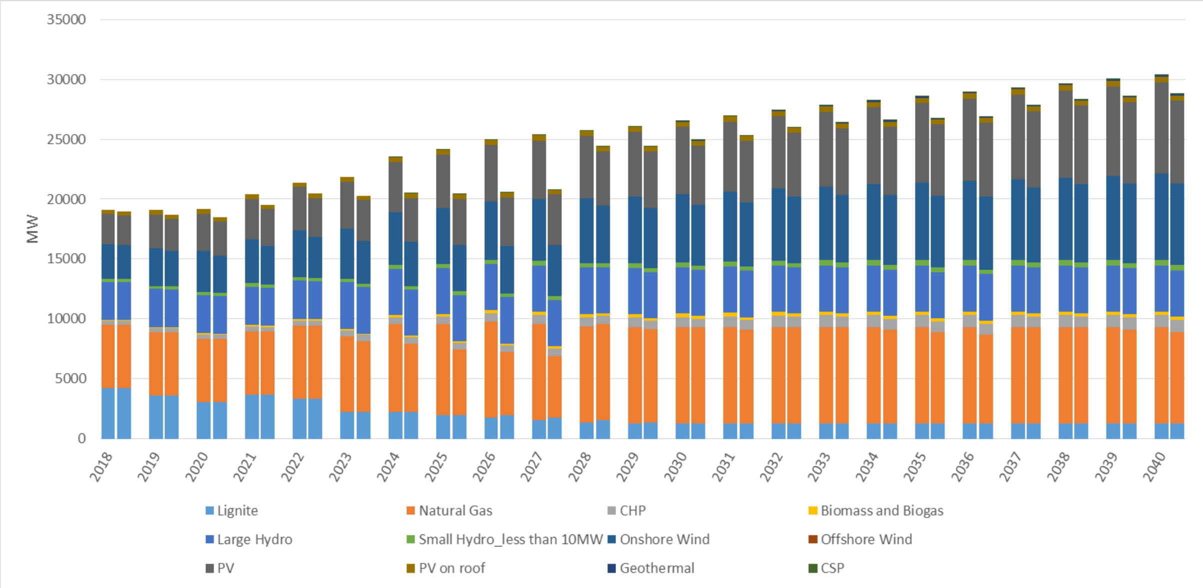


Figure 6.3: Evolution of the Greek Electricity Generation Mix – Value Added Maximization Approach

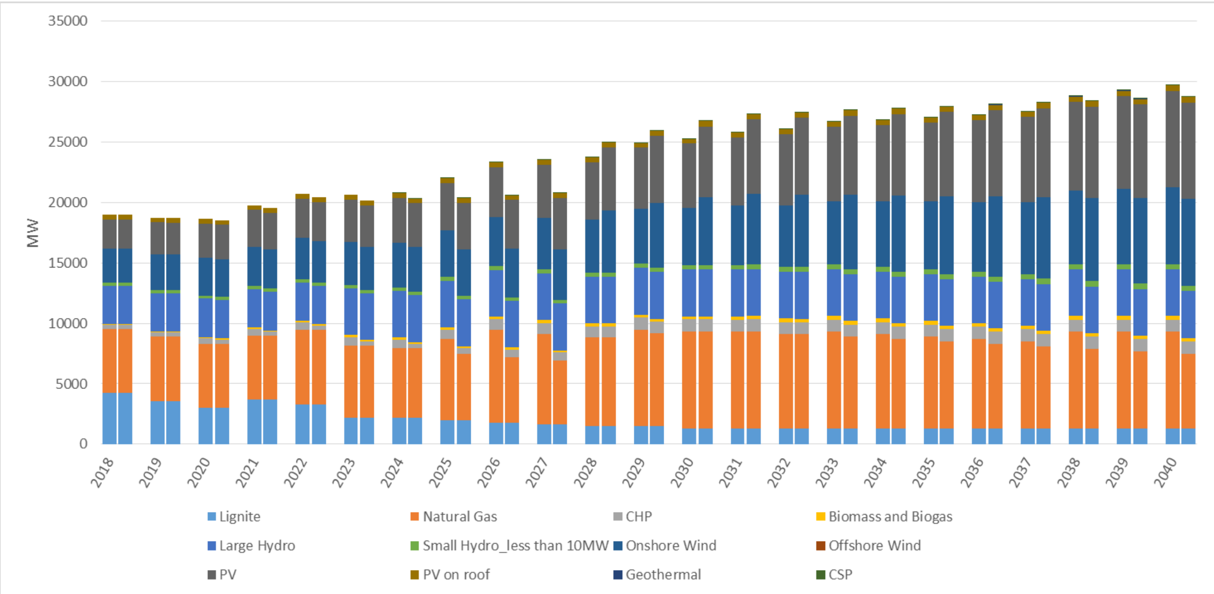


Figure 6.4: Evolution of the Greek Electricity Generation Mix – Monetary Outflows Minimization Approach

For the TAPC minimization approach, the 3-year case leads to lower annual installed capacity values than the ones of the annual case. This is explained by the fact that the 3-year optimization case allocates new capacity additions in a more cost-effective way as the annual, as it takes into account the evolution of –capital- costs.

The 3-year optimization case in the investments and value added maximization approaches, results to lower capacity values than the ones of the annual.

In the Monetary Outflows Minimization approach, the annual case (for the majority of the examined years) results to lower annual installed capacity values.

6.1.2 Production Mix – RES Share (%) – Electricity Imports Share (%)

The evolution of the electricity production mix as well as the RES and Electricity Imports Shares (%) for each optimization approach are presented in the following figures.

In the following figures, the evolution of the production mix has some differences in each optimization approach. This is explained by the fact that the annual electricity imports share is changing in each optimization method. Thus the shape of production's mix evolution is not the same under each optimization approach.

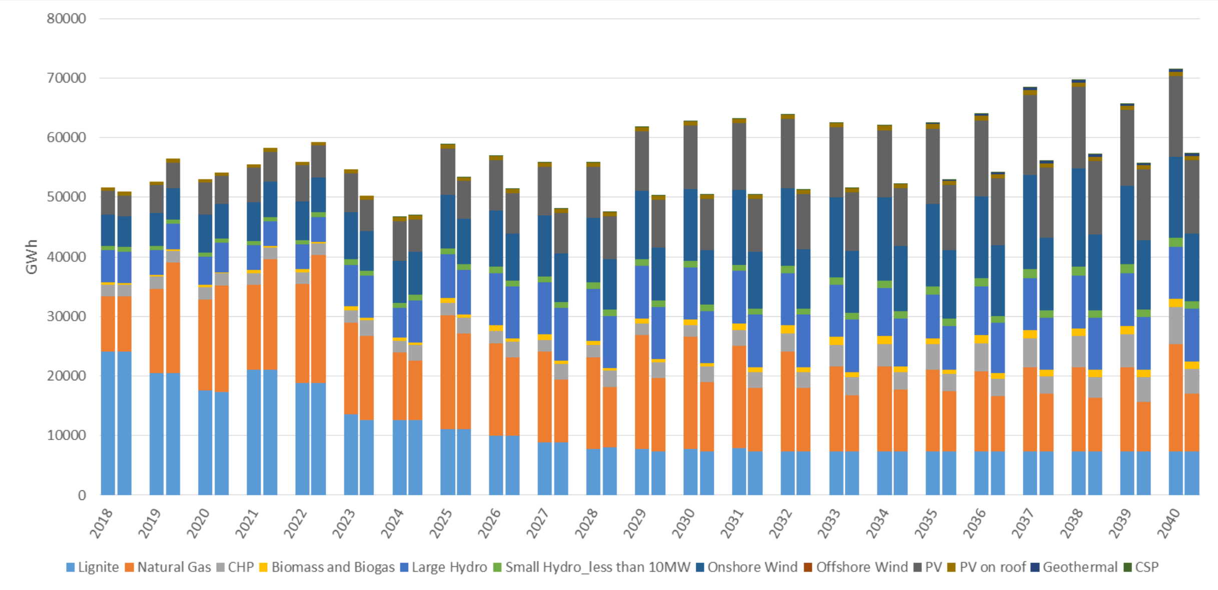


Figure 6.5: Evolution of the Greek Electricity Production Mix- TAPC Minimization Approach

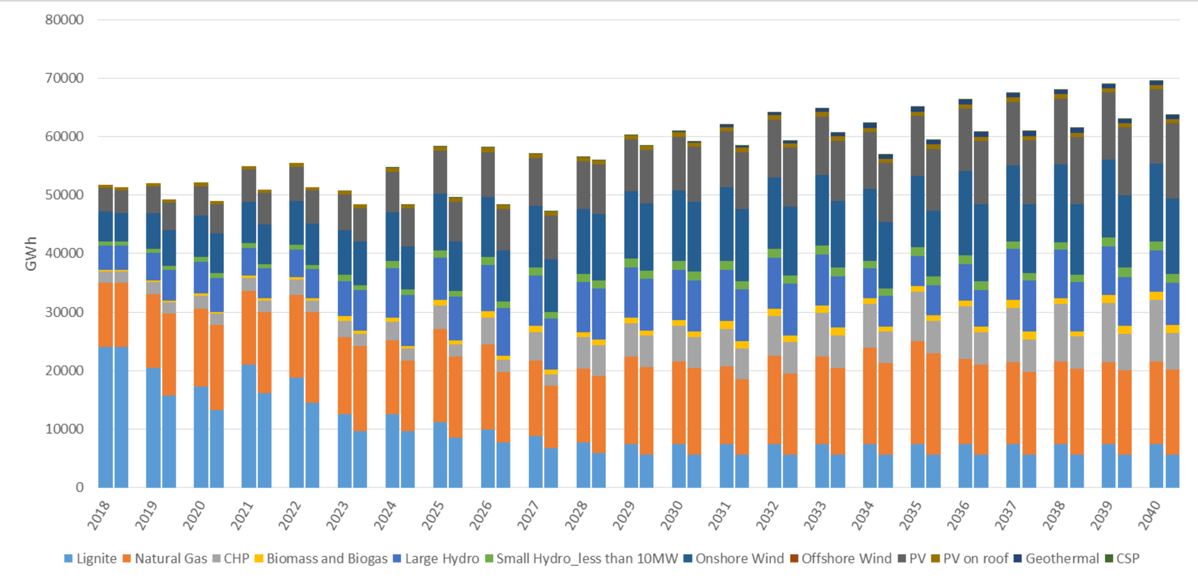


Figure 6.6: Evolution of the Greek Electricity Production Mix - Investments Maximization Approach

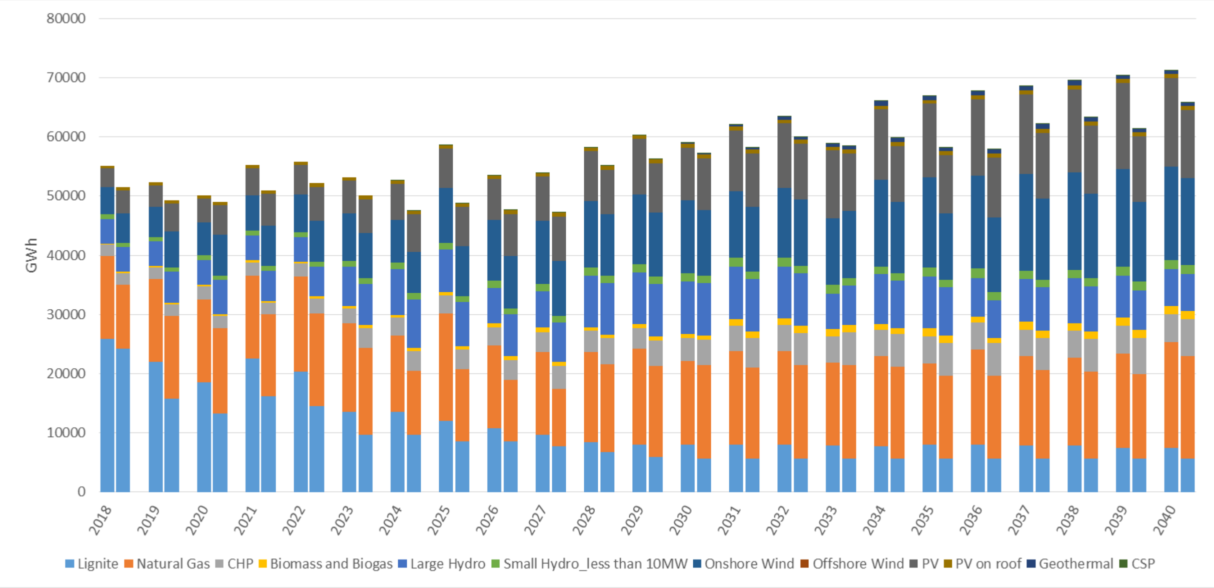


Figure 6.7: Evolution of the Greek Electricity Production Mix - Value Added Maximization Approach

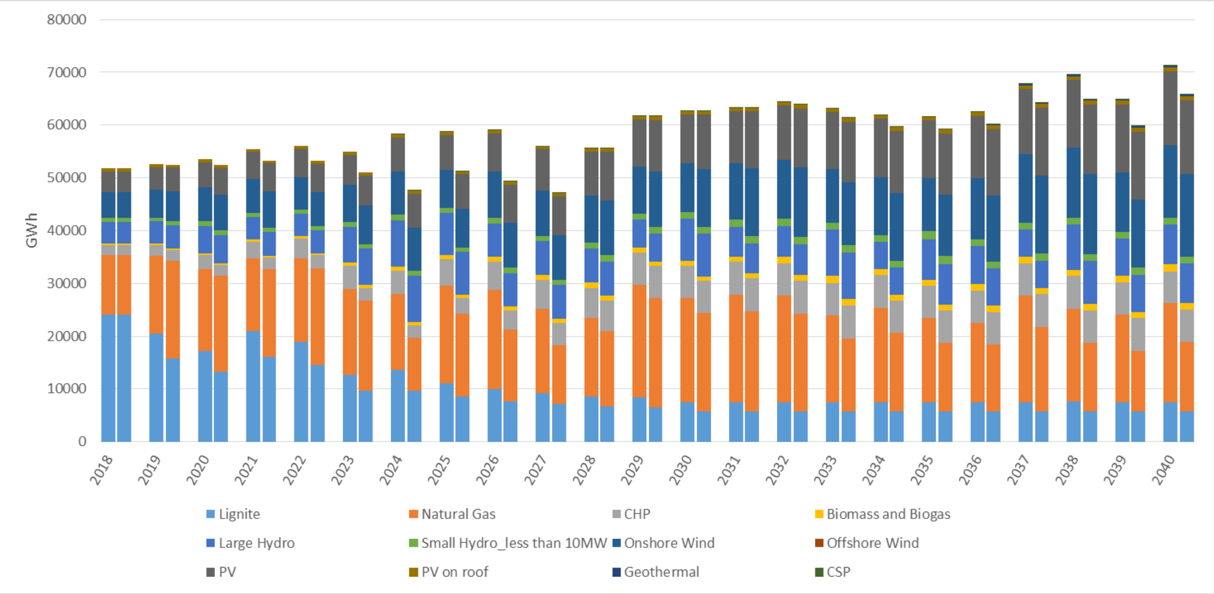


Figure 6.8: Evolution of the Greek Electricity Production Mix - Monetary Outflows Minimization Approach

It is evident, that the production mix regardless the optimization approach and case follows the evolution of the generation mix. Some differences may be occurred due to the annual variation in the electricity imports share value.

The following figures present the total annual electricity production for every optimization approach and case.

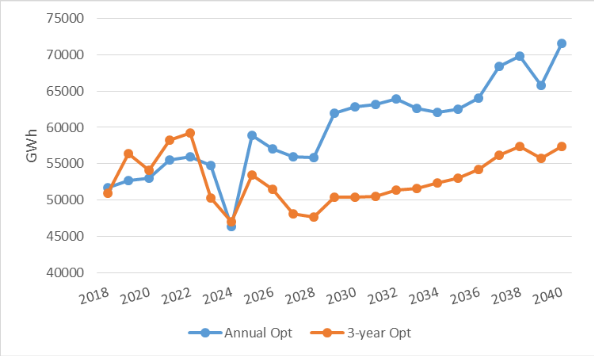


Figure 6.9: Total Annual Production TAPC Minimization

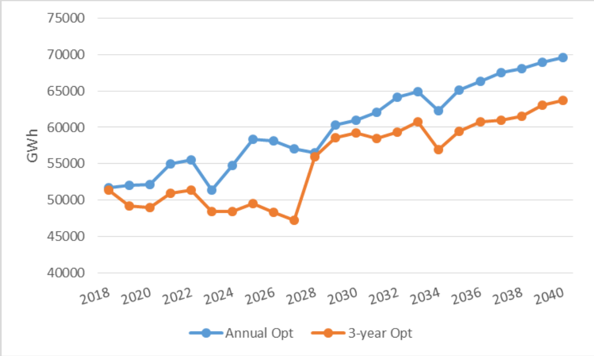


Figure 6.10: Evolution of Total Annual Production Investments Maximization

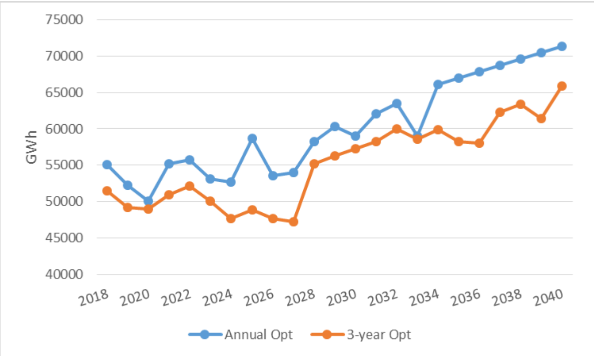


Figure 6.11: Total Annual Production Value Added Maximization

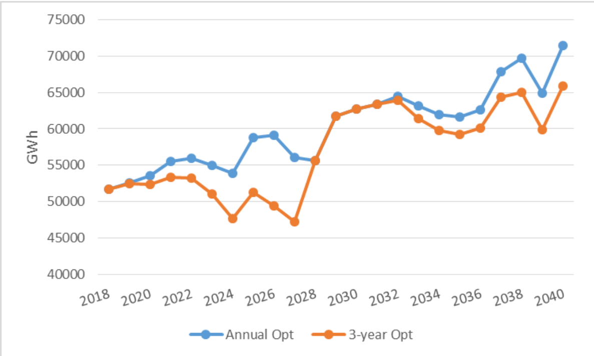


Figure 6.12: Evolution of Total Annual Production Monetary Outflows Minimization

In every optimization approach, the 3-year case leads to lower electricity production. This is explained by the fact that the 3-year case optimization favors electricity imports rather than dispatching the available installed capacity.

The following figures presents the electricity produced by Natural Gas stations for the two optimization cases.

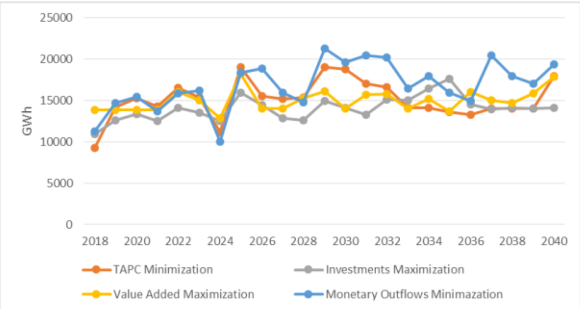


Figure 6.13: Evolution of Natural Gas Stations' electricity generation annual optimization case

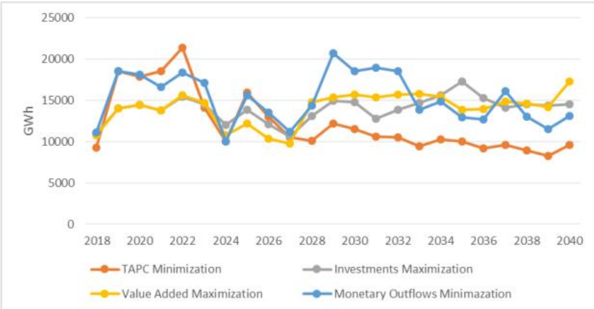


Figure 6.14: Evolution of Natural Gas Stations' electricity generation 3-year optimization case

The evolution of the natural gas stations' electricity generation for the annual optimization case is relatively the same for the different optimization approaches. The same applies to the 3-year optimization case. However, Figure 6.14 shows that the TAPC minimization approach leads to lower operation of Natural Gas Stations compared to the other approaches. The monetary outflow minimization approach despite some years where the production was in high levels keeps the production from natural gas stations at the level of 15 TWh.

The following figures present the annual electricity imports share for every optimization approach and case.

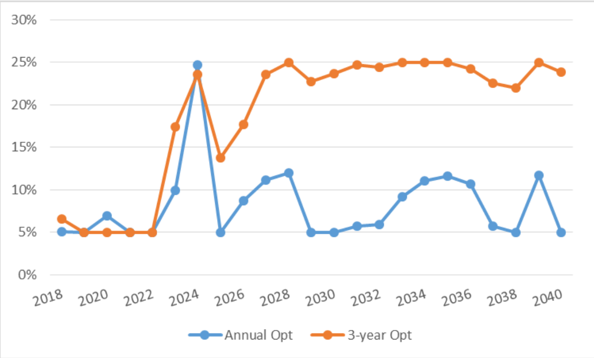


Figure 6.15: Annual Electricity Imports Share TAC Minimization

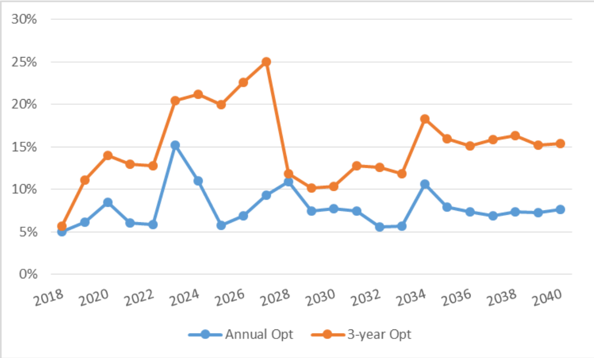


Figure 6.16 Annual Electricity Imports Share Investments Maximization

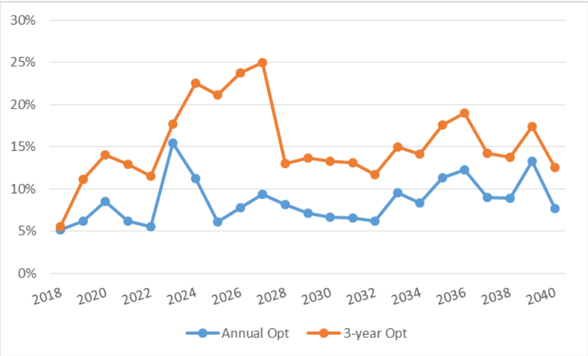


Figure 6.17: Annual Electricity Imports Share Value Added Maximization

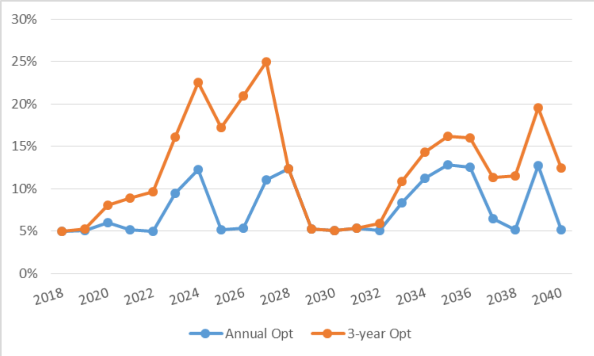
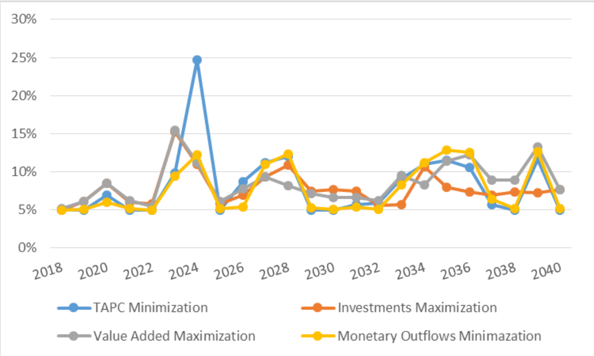


Figure 6.18: Annual Electricity Imports Share Monetary Outflows Minimization

It is obvious that the annual electricity imports shares are higher in the case of the 3-year optimization. This conclusion can be explained by the fact that a long-term planning of the operation of the electricity system should favor imports, as from the established interconnections and the international trading agreements, a country can achieve cost reductions.

Furthermore, as far as the investments and value added maximization approaches is concerned, the annual optimization case leads to significant lower electricity imports shares than the 3-year case. This is explained again by the fact, that on an annual basis the maximum capacity addition values are higher than the ones on a 3-year optimization (where the additions are more optimally allocated due to the fact that the cumulative results are maximized) and thus the dispatch of these new plants lowers the electricity imports.
The next two figures shows the evolution of electricity imports share for the same optimization case but for different approach.



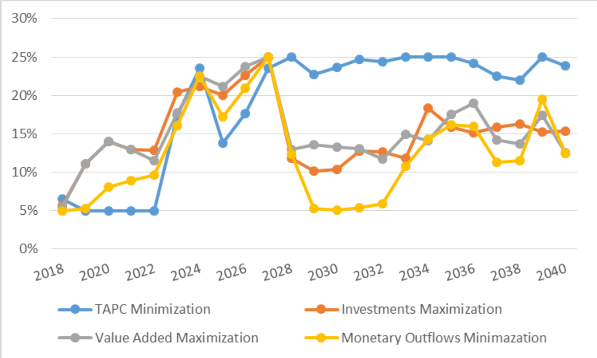


Figure 6.19: Annual Electricity Imports Share Annual optimization

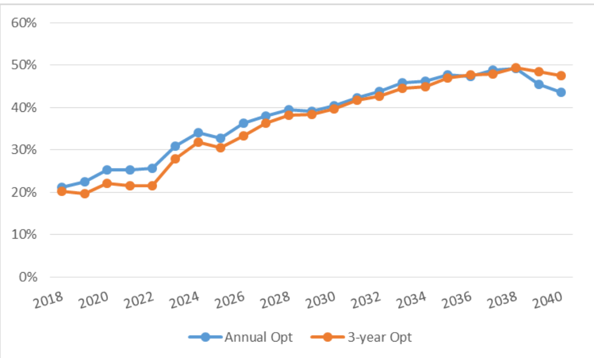
Figure 6.20: Annual Electricity Imports Share 3-year optimization

For the annual optimization case the electricity imports have generally the same trend. On the other hand, in the 3-year optimization case there are different trends for each optimization approach. In the monetary outflows minimization approach the electricity imports share is at low levels as expected. On the contrary, in the TAPC minimization the share of electricity imports is at high levels. The investments and value added maximization approaches have the same trends.

The RES Share in terms of domestic electricity production can be calculated by the following formula.

$$RES\ Share\ (\%) = \frac{\sum_{i=1}^{r} CF_i^z * Capacity_i^z(MW) * 8760h}{\sum_{i=1}^{n} CF_i^z * Capacity_i^z(MW) * 8760h} \qquad \textbf{(6.1-1)}$$

where *r* is the total number of technologies that can be characterized as renewables. In the case of this study, these technologies are the biomass-biogas, small hydropower, onshore and offshore wind, PVs, CSP and Geothermal plants.



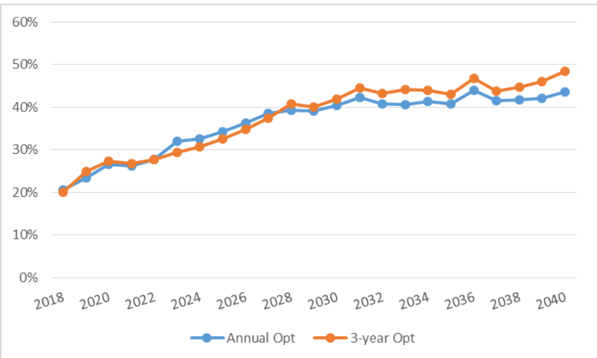
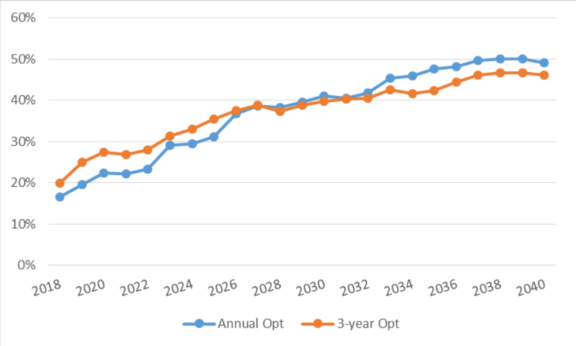


Figure 6.21: Annual RES Share (%) TAPC Minimization

Figure 6.22: Annual RES Share (%) Investments Maximization



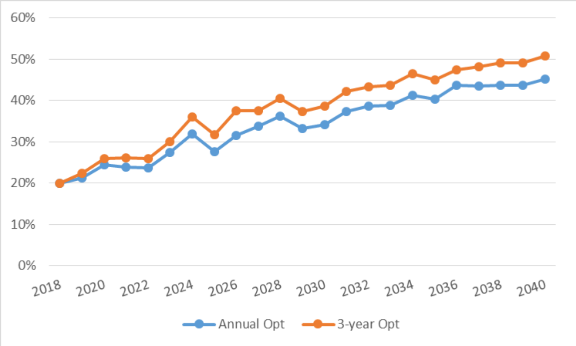


Figure 6.23: Annual RES Share (%) Value Added Maximization

Figure 6.24: Annual RES Share (%) Monetary Outflows Minimization

In every optimization case and approach, the RES Shares converge and at 2040 they are in the vicinity of 47-50%.

6.1.3 Total Annualized Production Cost-LCOE

The evolution of the Total Annualised Production Cost as well as the LCOE for each optimization approach and case are presented in the following figures.

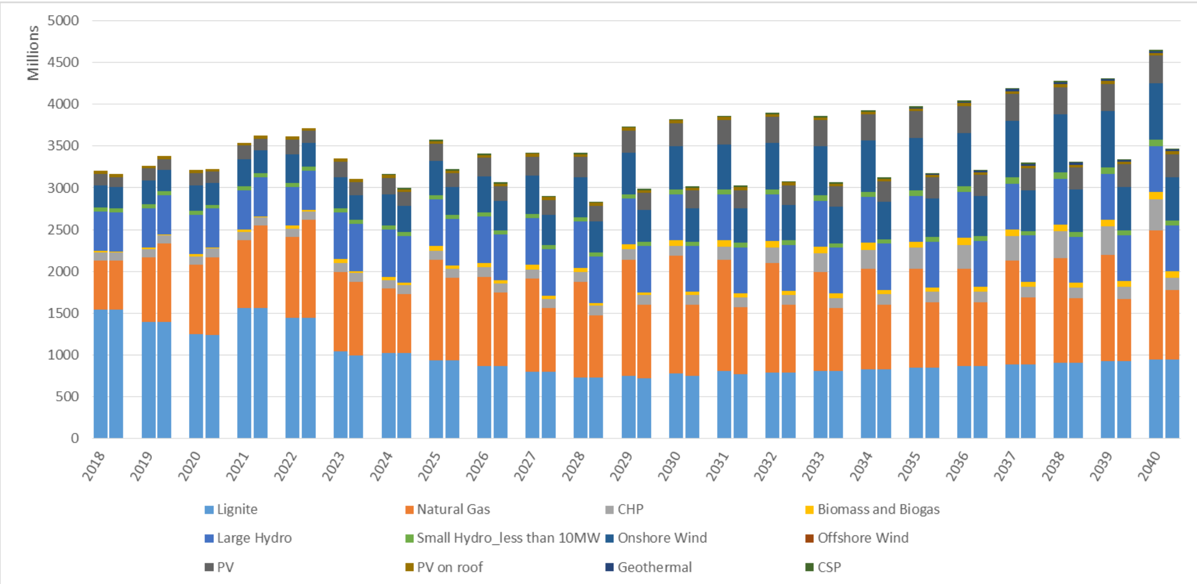


Figure 6.25: Evolution of the Total Annualized Production Cost (Million €) - TAPC Minimization Approach

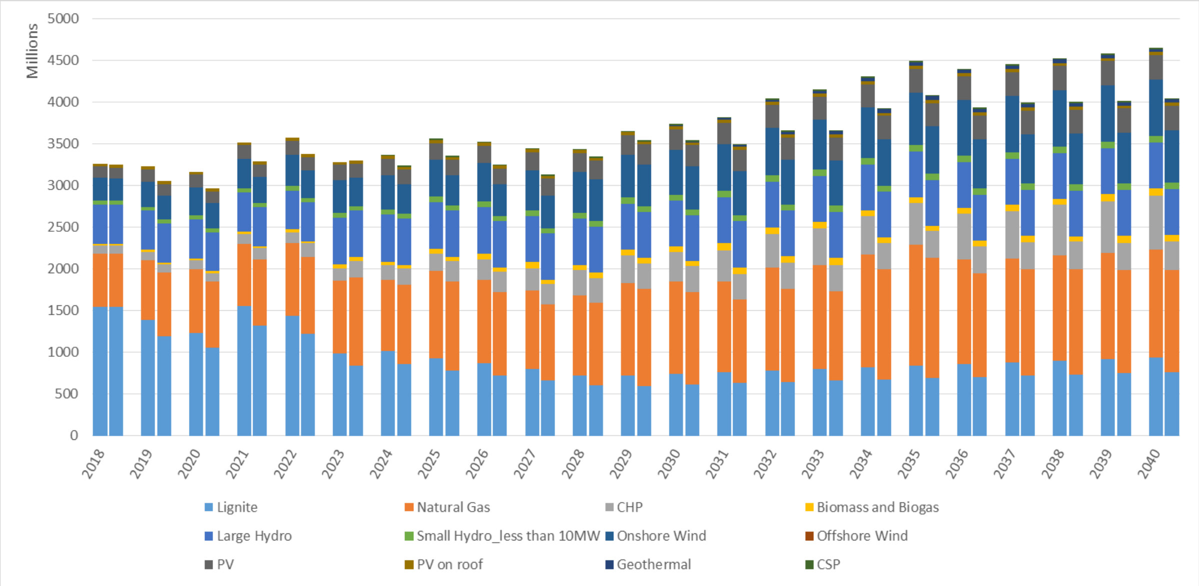


Figure 6.26: Evolution of the Total Annualized Production Cost (Million €) - Investments Maximization Approach

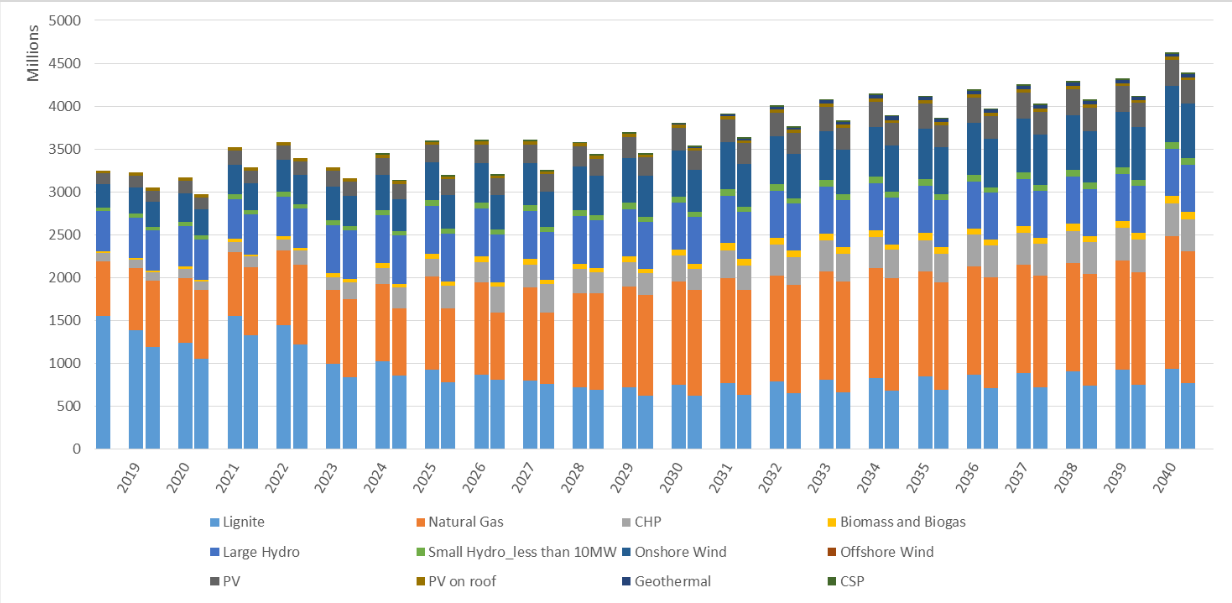


Figure 6.27: Evolution of the Total Annualized Production Cost (Million €) - Value Added Maximization Approach

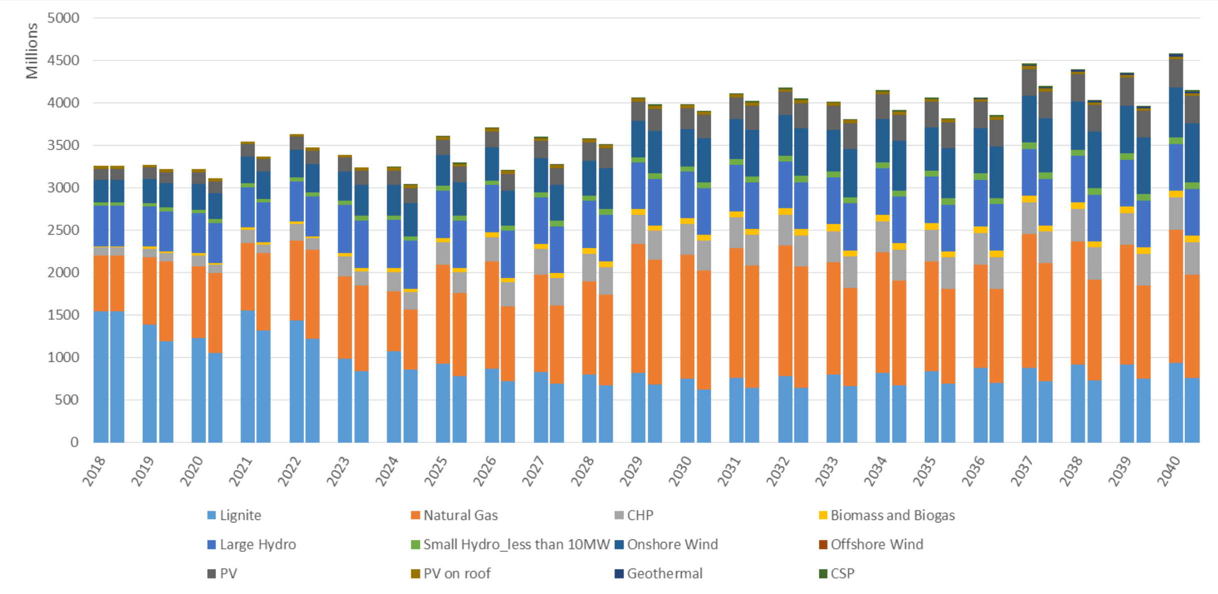


Figure 6.28: Evolution of the Total Annualized Production Cost (Million €) - Monetary Outflows Minimization

In the 3-year optimization case, in each optimization approach, the total annualized production cost is lower than the one in the annual optimization.

The cumulative Total Annualized Production Cost, for the entire examined period, for each optimization approach and case is presented in the following figure.

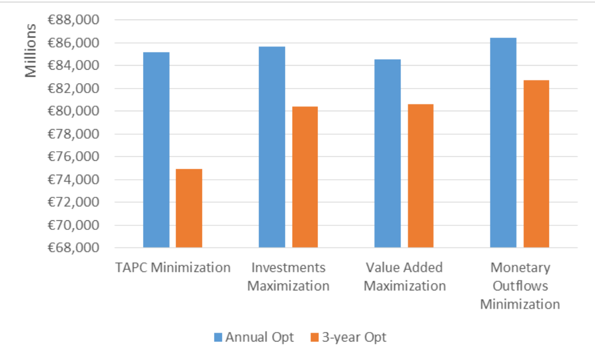


Figure 6.29: Comparison of Cumulative TAPC

The Cumulative Total Annualized Production Cost under the 3-year optimization case is lower than the one in the annual case, for each optimization approach. In addition, in the 3-year optimization case the cumulative TAPC, in the TAPC minimization approach is the lowest compared to the rest approaches (circa 75 billion). This is a validation of the simplified model's TAPC's optimization approach functionality.

The Levelized Cost of Energy (LCOE) (€/MWh) can be calculated by dividing the total TAPC in each year with the total electricity production in the same year.

$$LCOE^z\left(\frac{€}{MWh}\right) = \frac{\sum_{i=1}^{n} TAPC_i^z}{\sum_{i=1}^{n} CF_i^z * Capacity^z(MW) * 8760h} \quad \textbf{(6.1-2)}$$

where *i* represents the technology, *z* the year and *n* the total number of technologies constituting the electricity system.

The following figures presents the evolution of the LCOE for each optimization approach, compared to the two optimization cases.

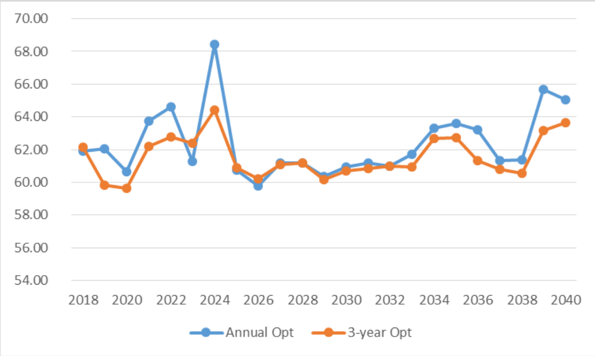


Figure 6.30: Annual LCOE (€/MWh) TAPC Minimization

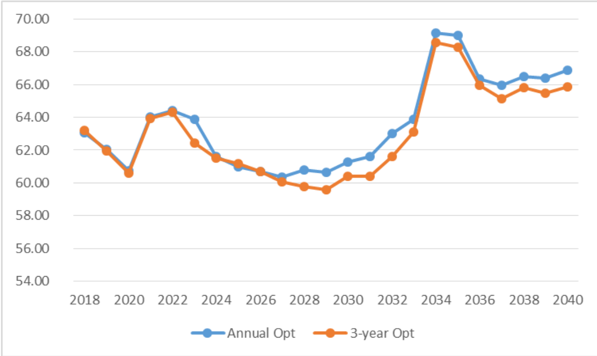


Figure 6.31: Annual LCOE (€/MWh) Investments Maximization

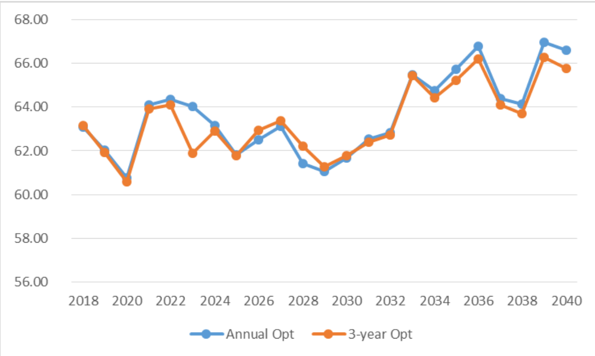


Figure 6.32: Annual LCOE (€/MWh) Value Added Maximization

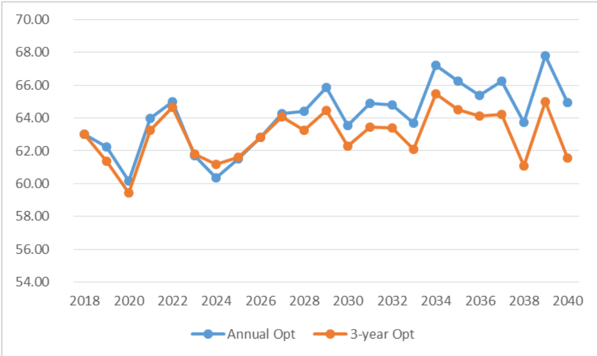


Figure 6.33: Annual LCOE (€/MWh) Monetary Outflows Minimization

The annual LCOE in each optimization case for the same approach shows convergence. The next figures compare the LCOE, for the same optimization case but for different optimization approach.

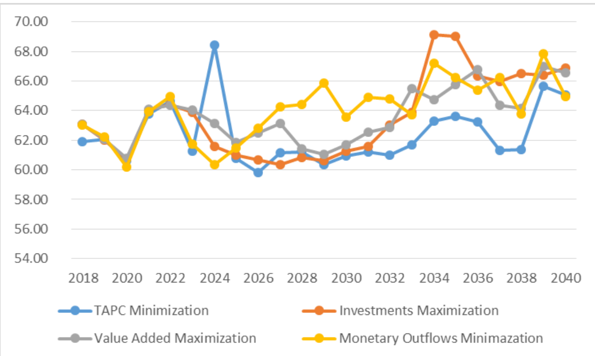


Figure 6.34: Annual LCOE (€/MWh) Annual optimization case

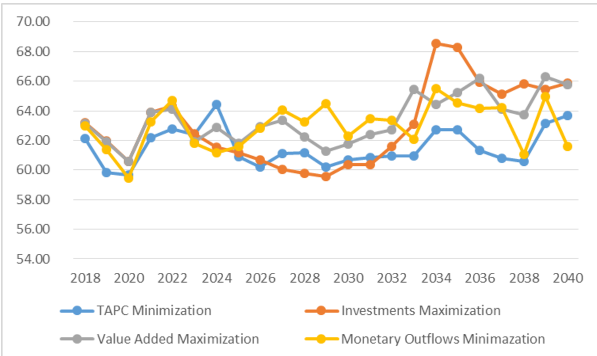


Figure 6.35: Annual LCOE (€/MWh) 3-year optimization case

In both optimization cases, the LCOE varies in every year due to the fluctuation in the annual electricity import share values. Despite this fact, the TAPC minimization approach leads in most years to lower LCOE values.

On the other hand, the Monetary Outflows Minimization approach as it attempts to decrease the rate in which new capacity additions are taking place (an element of monetary outflows is the share of capital costs that exits the country) leads to lower LCOE values (in some years the values increased due to the low electricity shares value) and higher in those where the electricity imports share is increased. The investments and value added maximization approaches, for the majority of the examined years have the same trend.

6.1.4 Investments

In every examined scenario, instead of decommissioning RES plants (onshore wind and PVs), repowering as an alternative course of action is being considered. Therefore, the onshore wind and PV capacities described in Section 3.2.5 multiplied with the repowering costs (see section 3.2.6.d) of each technology, will be an additional investment that will take place in the examined period. This repowering investment will be part of the total investment activity of the RES technology (i.e. onshore wind or PVs) that will be repowered.

$$RESRepoweringInvestment(€) = RepoweringCost\left(\frac{€}{MW}\right) * PlannedCapacityRetirement\ (MW) \quad \textbf{(6.1-3)}$$

The evolution of the Total Annual Investments for each optimization approach and case are presented in the following figures.

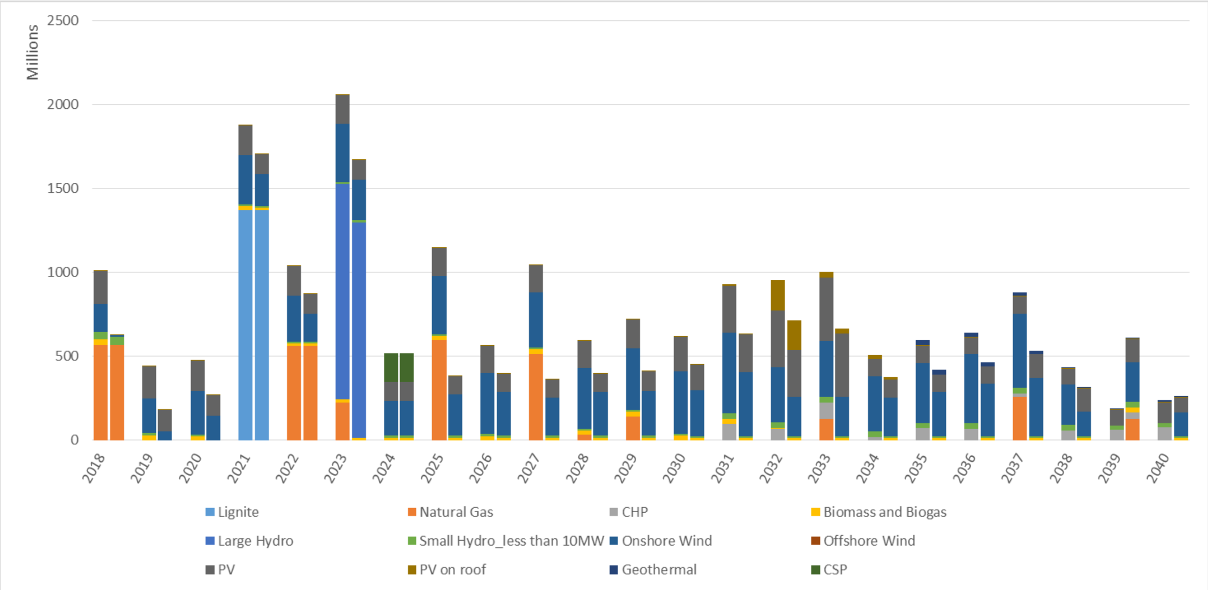


Figure 6.36: Evolution of the Total Annual Investments (Million €) – TAPC Minimization

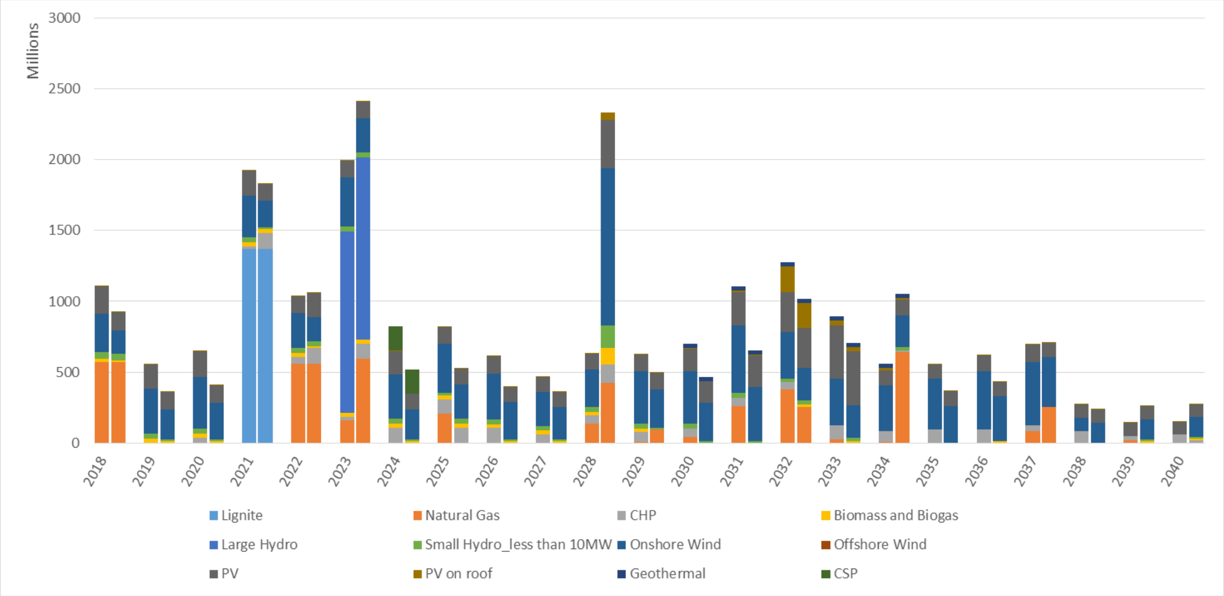


Figure 6.37: Evolution of the Total Annual Investments (Million €) – Investments Maximization

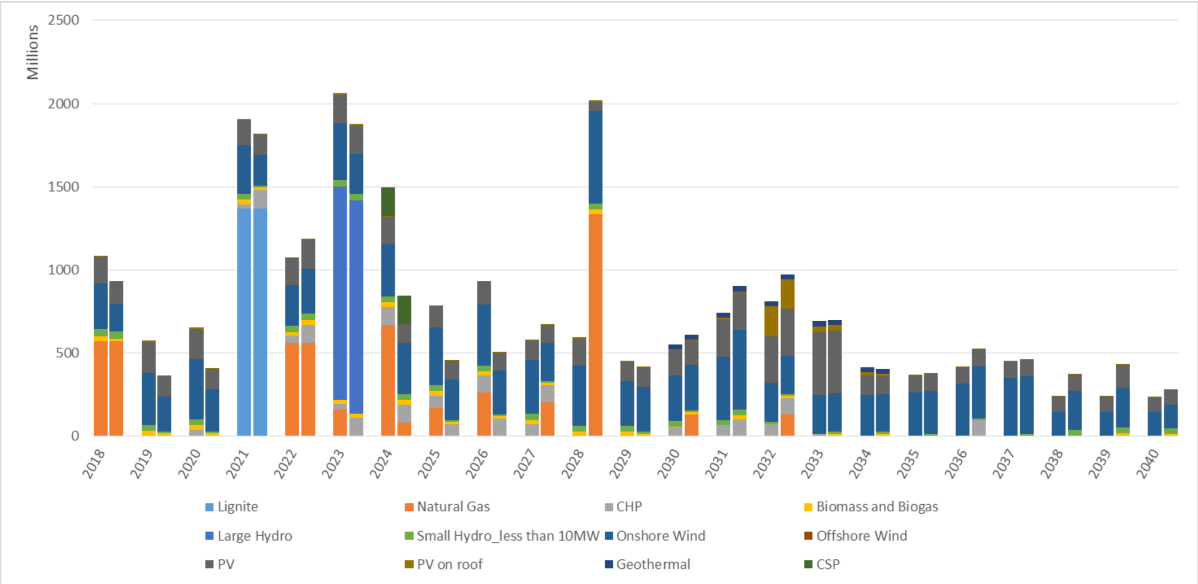


Figure 6.38: Evolution of the Total Annual Investments (Million €) – Value Added Maximization

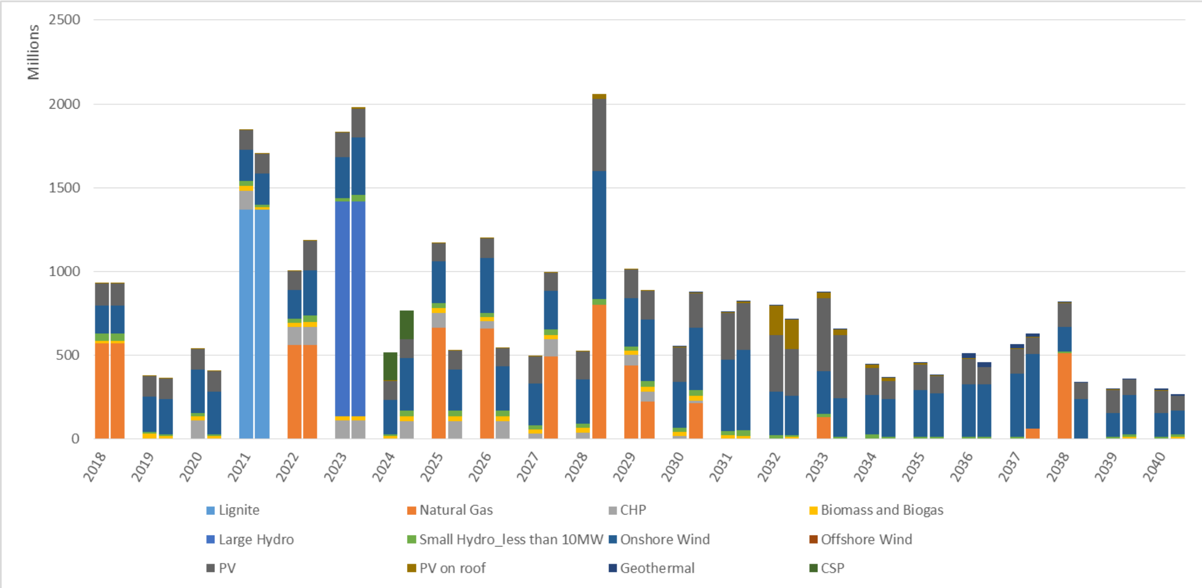


Figure 6.39: Evolution of the Total Annual Investments (Million €) – Monetary Outflows Minimization

These graphs present the annual investment activity for each optimization approach and case. However, the comparison between the two optimization cases as well as the differences of each optimization approach can be explained in a more accurate way in the cumulative investment results which are presented as follows.

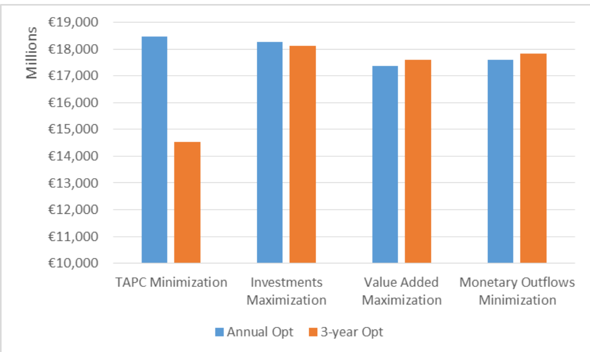


Figure 6.40: Cumulative Investments

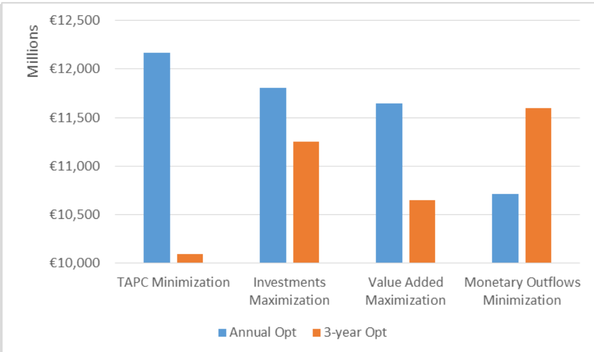


Figure 6.41: Cumulative RES Investments

In the 3-year optimization case the investments maximization approach leads to higher cumulative total investments. The cumulative investment in the monetary outflows minimization case is at the same level as the one for the investments maximization approach. This is explained by the fact that the cumulative investments in RES technologies are at high levels in the Monetary Outflows Minimization approach. Investing at higher rates in RES plants than in plants that use for instance natural gas as fuel leads to lower levels of monetary outflows. Therefore, the high level of investment activity in the monetary outflows maximization approach is contributed to the high level of RES investments.

6.1.5 Value Added

The Total Value Added for each optimization approach is presented in the following figures.

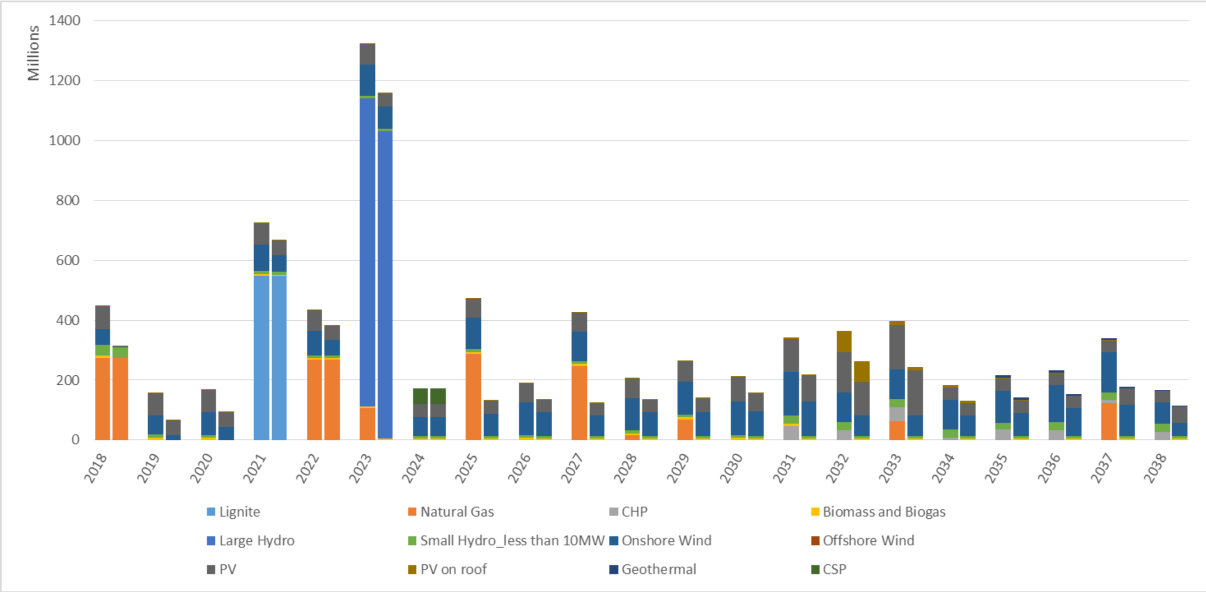


Figure 6.42: Total Annual Value Added (Million €) - TAPC Minimization

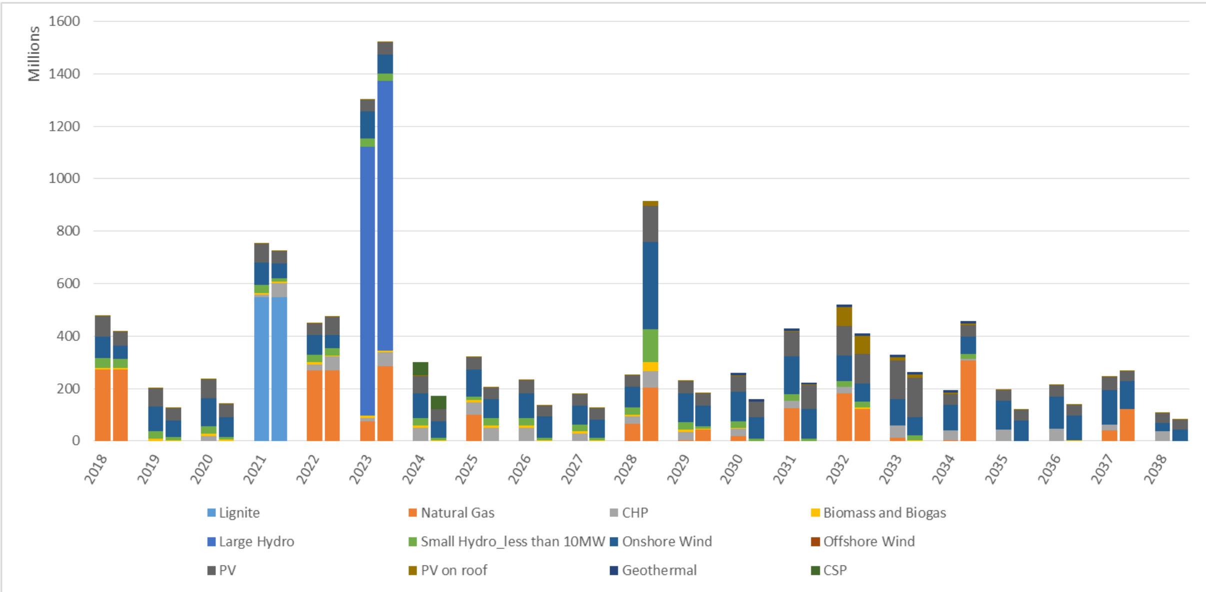


Figure 6.43: Total Annual Value Added (Million €) - Investments Maximization

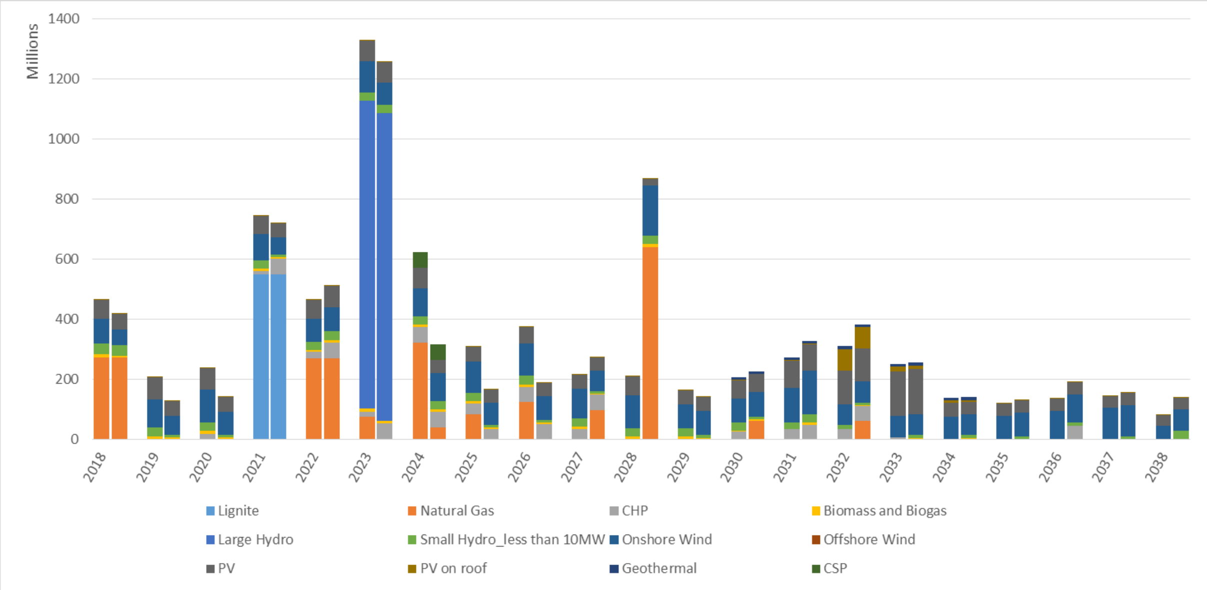


Figure 6.44: Total Annual Value Added (Million €) - Value Added Maximization

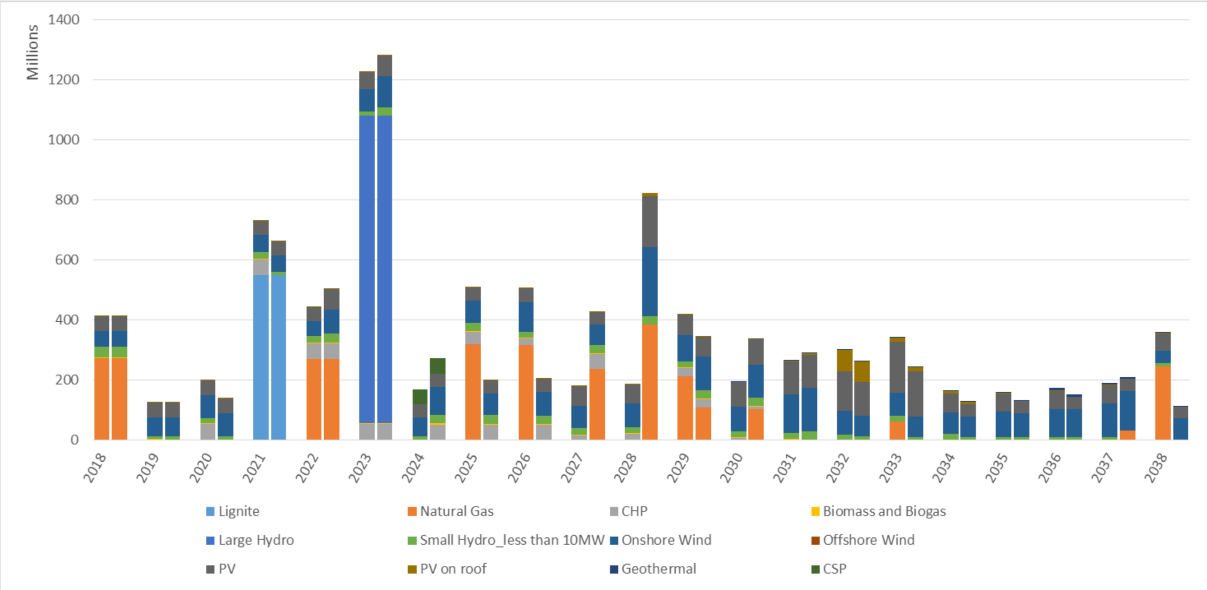


Figure 6.45: Total Annual Value Added (Million €) - Monetary Outflows Minimization

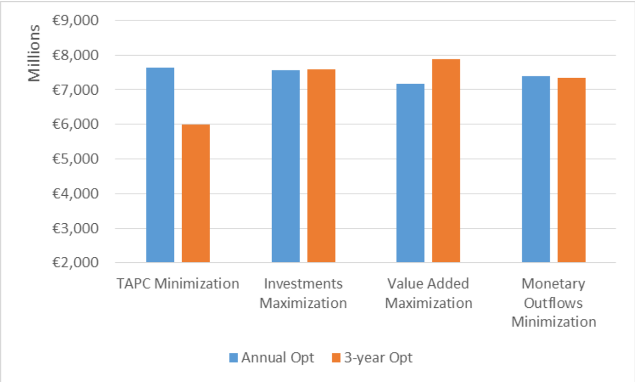


Figure 6.46: Cumulative Value Added

Figure 6.46, shows that the annual optimization case does not lead to the highest cumulative value added in the approach of value added maximization. On the other hand, in the 3-year optimization case the investments - value added maximization and the monetary outflows minimization approaches have relatively the same level of cumulative value added. This conclusion is in line with the cumulative investments results.

6.1.6 Monetary Outflows

The evolution of the Total Monetary Outflows for each optimization approach and case are presented in the following figures.

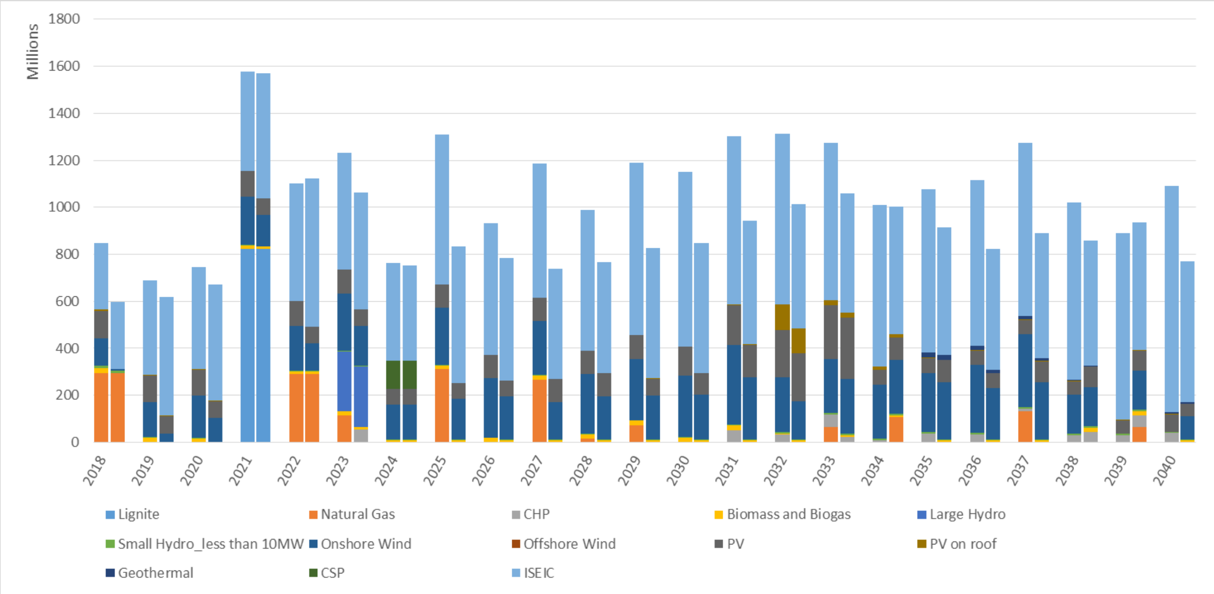


Figure 6.47: Total Annual Monetary Outflows (Million €) - TAPC Minimization

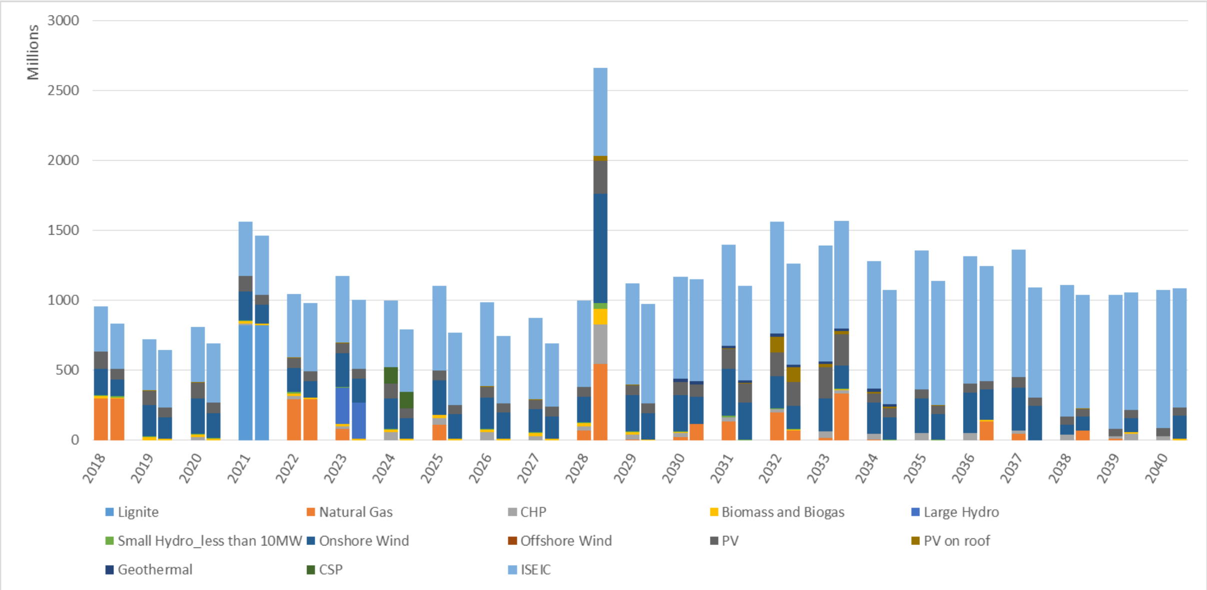


Figure 6.48: Total Annual Monetary Outflows (Million €) - Investments Maximization

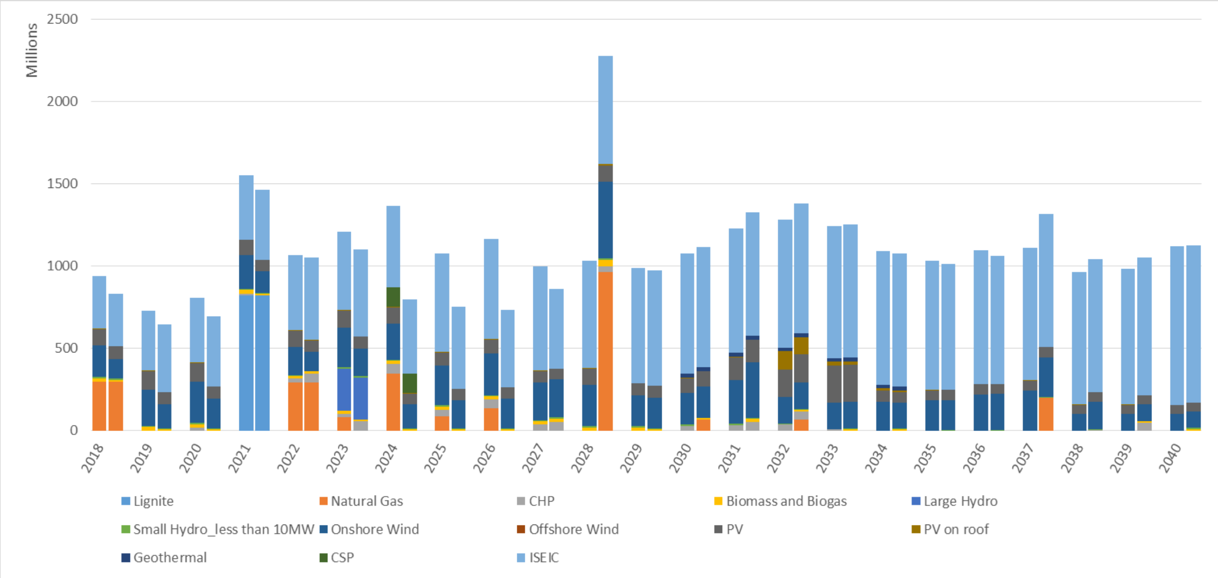


Figure 6.49: Total Annual Monetary Outflows (Million €) - Value Added Maximization

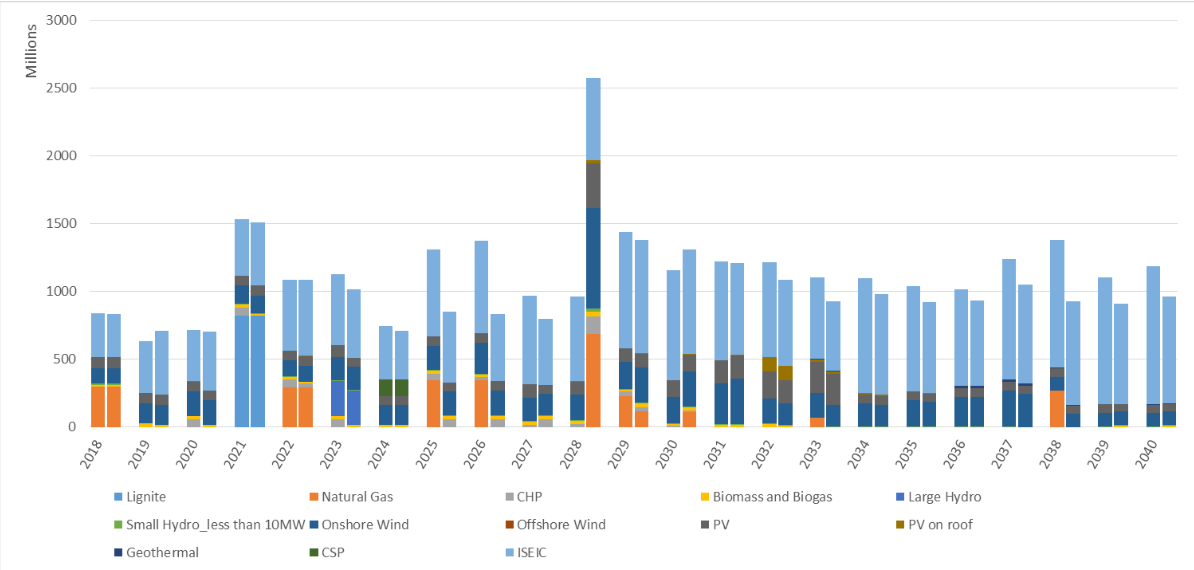


Figure 6.50: Total Annual Monetary Outflows (Million €) - Monetary Outflows Minimization

These graphs present the monetary outflows for each optimization approach and case. However, the comparison between the two optimization cases as well as the differences of each optimization approach can be explained in a more accurate way in the cumulative ISEIC and monetary outflows results which are presented as follows.

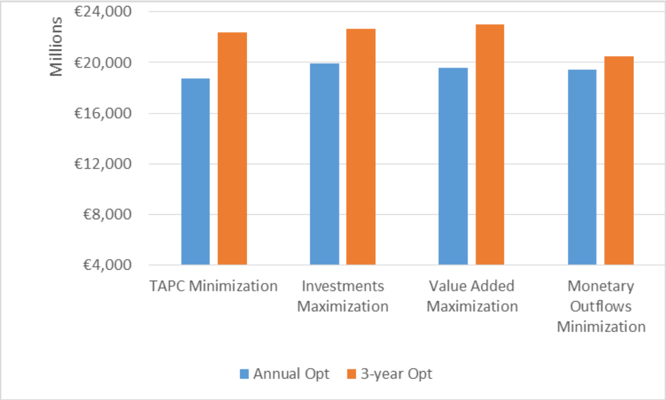


Figure 6.51: Cumulative ISEIC

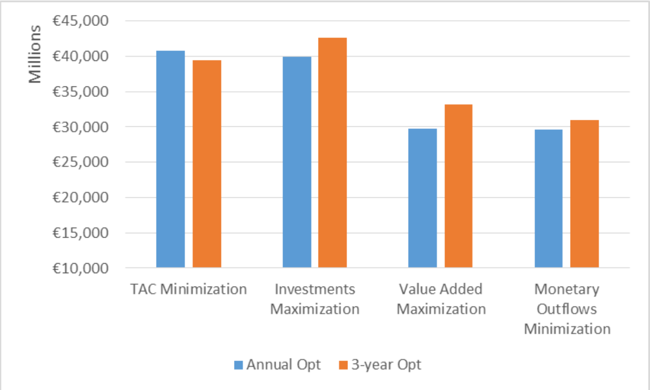


Figure 6.52: Cumulative Monetary Outflows

Regarding the ISEIC results, in every optimization approach and case the cumulative results are in the same level. This is explained by the fact that in every approach the operation of natural gas generally is at the same levels. In addition, comparing the electricity imports share evolution and the one of electricity production from natural gas stations (thus the natural gas fuel consumption), it can be stated that the two measures have negative correlation. Thus, the cumulative ISEIC is at the same level for every optimization approach.

Regarding the monetary outflows, the TAPC minimization approach and the investments maximization approach have the highest values of cumulative monetary outflows. In the TAPC minimization the electricity imports shares are at high levels and thus the contribution of them in the cumulative monetary outflows is high. In addition, when the investment activity is at high levels the capital costs that exits the country are significant and as a consequence the monetary outflows increase.

The value added maximization and the monetary outflows minimization approaches have the same level of cumulative monetary outflows. This conclusion was expected as the value added maximization approach lead to significant high RES investment activity which has less impact in the cumulative monetary outflows.

6.1.7 Employment Effects

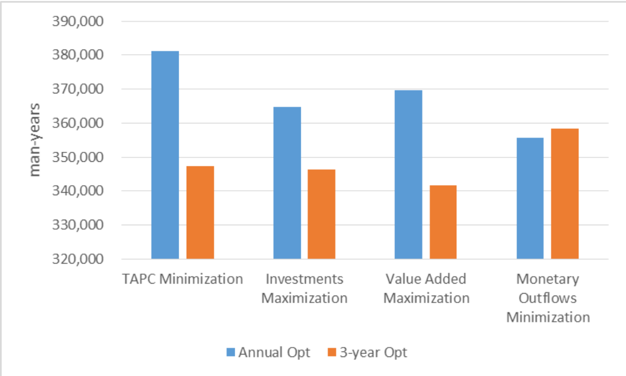
Regarding the employment effects, the annual direct, indirect or induced employment effect, for each technology, can be calculated by applying the following formula.

$$EmploymentEffect_i^z(man-years) = Capacity_i^z(MW) * CF_i^z(\%) * 8760h/10\text{^}6 * Employment\_Factor_i(\frac{man-years}{TWh}) \quad \textbf{(6.1-4)}$$

where $Employment\_Factor(\frac{man-years}{TWh})$ is a factor for calculating the man-years generated for each technology, per TWh of electricity produced. These factors can be found in Table 3.17. The cumulative employment effects for the entire examined period are therefore calculated by the following formula.

$$CumulativeEmploymentEffects(man-years) = \sum_{z=2018}^{2040} \sum_{i=1}^{n} EmploymentEffect_i^z \quad \textbf{(6.1-5)}$$

The Cumulative (for the entire examined period) Direct, Indirect and Induced Employment Effects for each optimization approach, taking into consideration the two cases of optimization are presented in the following figures.



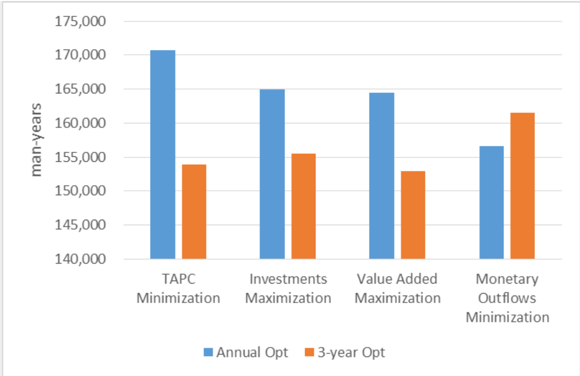


Figure 6.53: Cumulative Direct Employment effects

Figure 6.54: Cumulative Indirect Employment effects

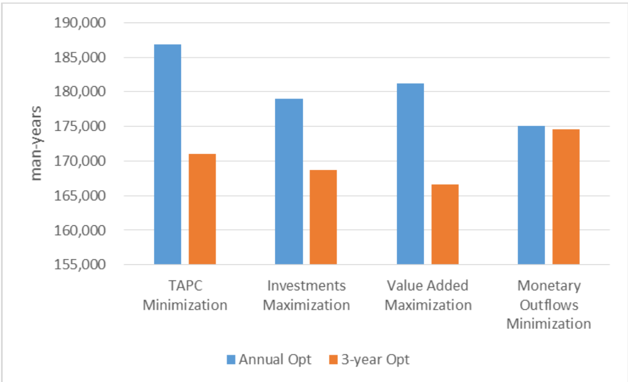


Figure 6.55: Cumulative Induced Employment Effects

In the annual optimization case, the higher employment effects are in the TAPC minimization approach. On the other hand, as the total domestic electricity production activity is generally higher in the Monetary Outflows Minimization approach, the employment effects in the Monetary Outflows Minimization approach compared to the other optimization approaches are at higher levels.

6.1.8 Injuries & Fatalities

The injuries and fatalities as well as their cumulative values can also be calculated by applying the injuries and fatalities factor, introduced in Section 3.1.10.

$$Injuries_i^z(no.of\ injuries) = Capacity_i^z(MW) * CF_i^z(\%) * 8760h/10\text{^}6 * Injuries\_Factor_i(\frac{man-years}{TWh}) \quad \textbf{(6.1-6)}$$

$$CumulativeInjuries(no.of\ injuries) = \sum_{z=2018}^{2040}\sum_{i=1}^{n} Injuries_i^z \quad \textbf{(6.1-7)}$$

$$Fatalities_i^z(no.of\ fatalities) = Capacity_i^z(MW) * CF_i^z(\%) * 8760h/10\text{^}6 * Fatalities\_Factor_i(\frac{man-years}{TWh}) \quad \textbf{(6.1-8)}$$

$$CumulativeFatalities(no.of\ fatalities) = \sum_{z=2018}^{2040}\sum_{i=1}^{n} Fatalities_i^z \quad \textbf{(6.1-9)}$$

The injuries factors can be found Table 3.17.

The Cumulative Injuries from the operation of the power system, for every optimization approach and case, are presented in the following figures.

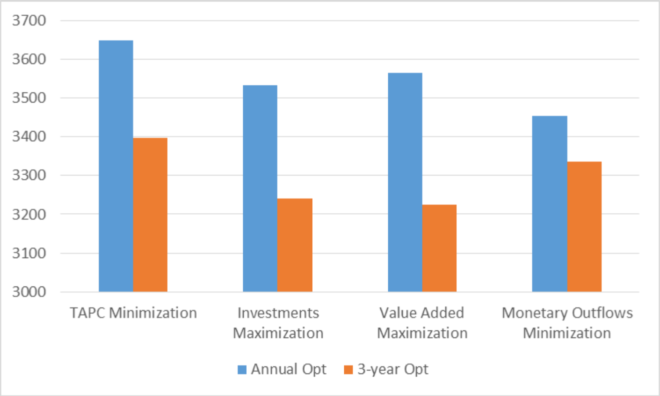


Figure 6.56: Cumulative Injuries

From the above figure, the highest level of cumulative injuries is observed in the TAPC minimization approach.

The fatalities under each optimisation approach totals for the examined period to 8 deaths for the annual optimization approach and to 7 deaths for the 3-year approach

6.1.9 Emissions

The CO_2 emissions presented in the following sections are the ones generated from the each technology that constitutes the entire power system. The emission factors, introduced in Section 3.1.8. have been derived from a Life-Cycle-Analysis (LCA) methodology. Therefore, the CO_2 emissions from the entire power system both on an annual basis and for the entire examined period can be calculated from the following formulas.

$$CO_2Emissions^z(million\ tonnes\ of\ CO_2) = \sum_{i=1}^{n} EmissionFactor_i(\frac{kg}{kWh}) * Capacity_i^z(MW) * CF_i^z(\%) * 8760h/10^6 \quad \textbf{(6.1-10)}$$

$$CumulativeCO_2Emissions = \sum_{z=2018}^{2040} \sum_{i=1}^{n} CO_2Emissions^z \quad \textbf{(6.1-11)}$$

The CO_2 emissions for the entire power system, for each optimization approach, are presented in the following figures.

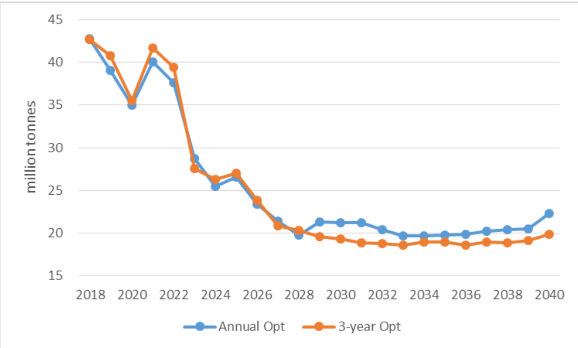


Figure 6.57: Annual CO_2 Emissions TAPC Minimization

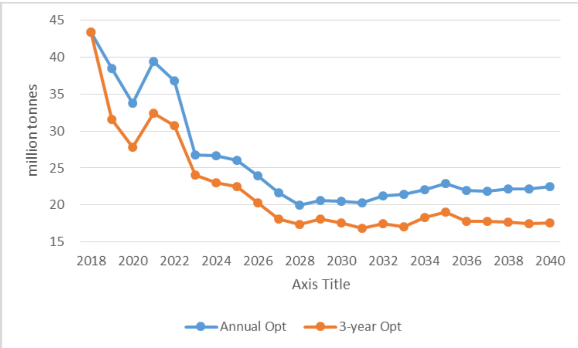


Figure 6.58: Annual CO_2 Emissions Investments Maximization

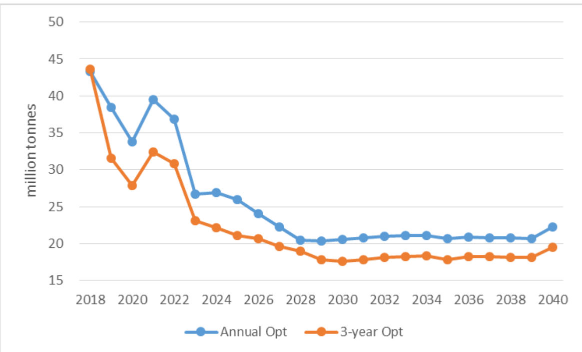


Figure 6.59: Annual CO_2 Emissions Value Added Maximization

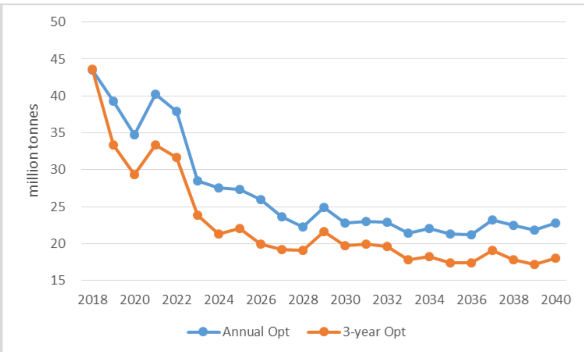


Figure 6.60: Annual CO_2 Emissions Monetary Outflows Minimization

The 3-year optimization case, for the same optimization approach, leads to lower annual CO_2 emissions.

The following figure presents the cumulative CO_2 emissions for every optimization method and case.

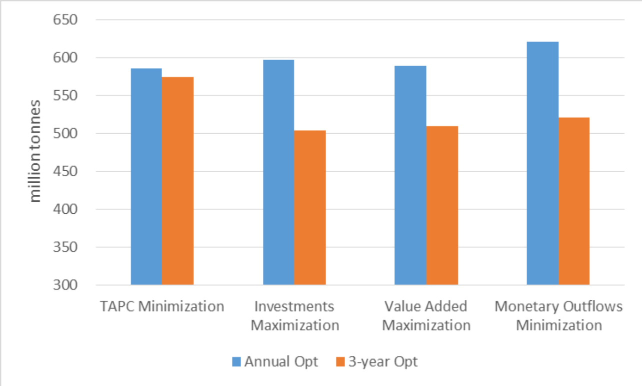


Figure 6.61: Cumulative CO_2 Emissions

The cumulative CO_2 emissions in the TAPC minimization approach for the 3-year optimization case, show an increase in years 2021 and 2022 the production form lignite and natural gas plants show an increase.

6.2 Alternative Demand Scenarios-The role of Natural Gas Stations

For the various demand scenarios, the overall evolution of the electricity system is being presented. As mentioned in the previous chapter the optimization method that is applied is the TAPC Minimization with a 3-year approach. In addition, the role of natural gas stations for the three different demand scenarios that are examined is also analyzed.

6.2.1 Electricity Generation Mix (Installed Capacity)

The electricity generation mix (installed capacity), for each demand scenario, is presented in the following figures.

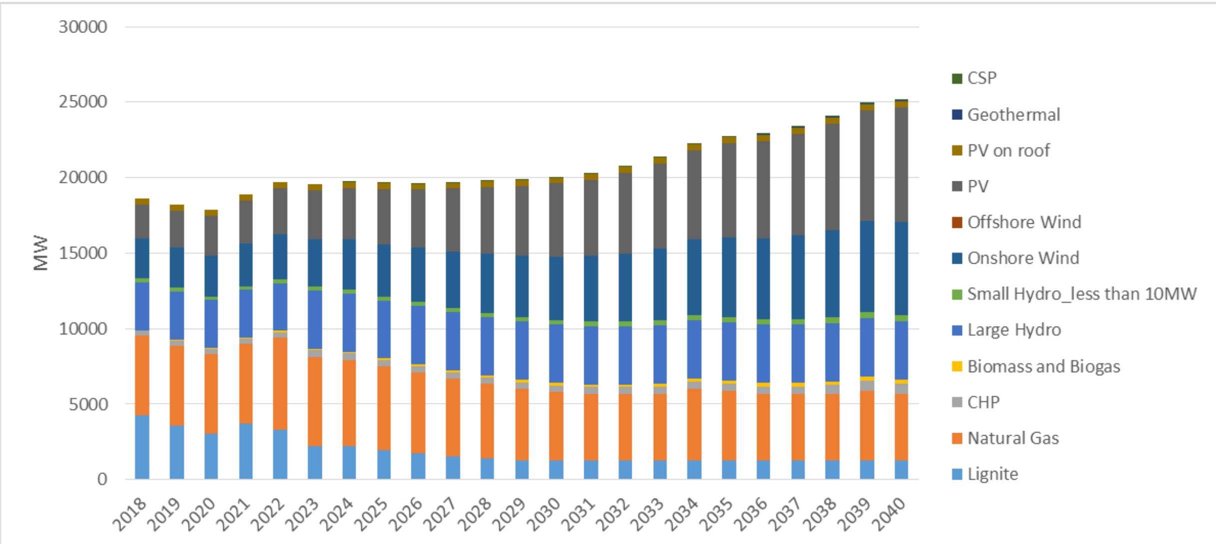


Figure 6.62: Evolution of the Greek Electricity Generation Mix – Reference Demand Scenario.

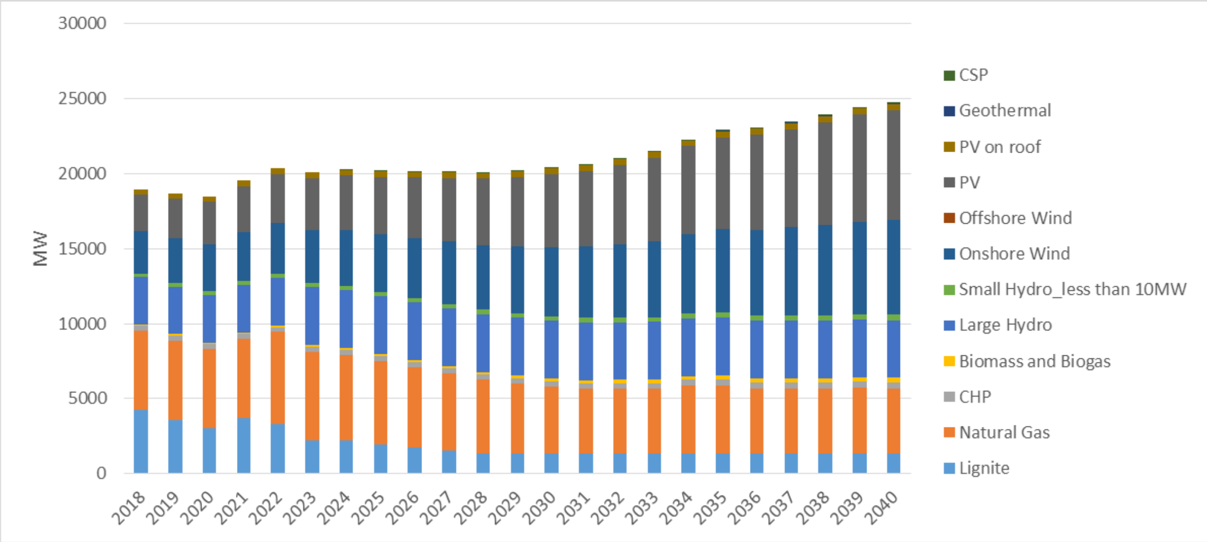


Figure 6.63: Evolution of the Greek Electricity Generation Mix – Low Demand Scenario.

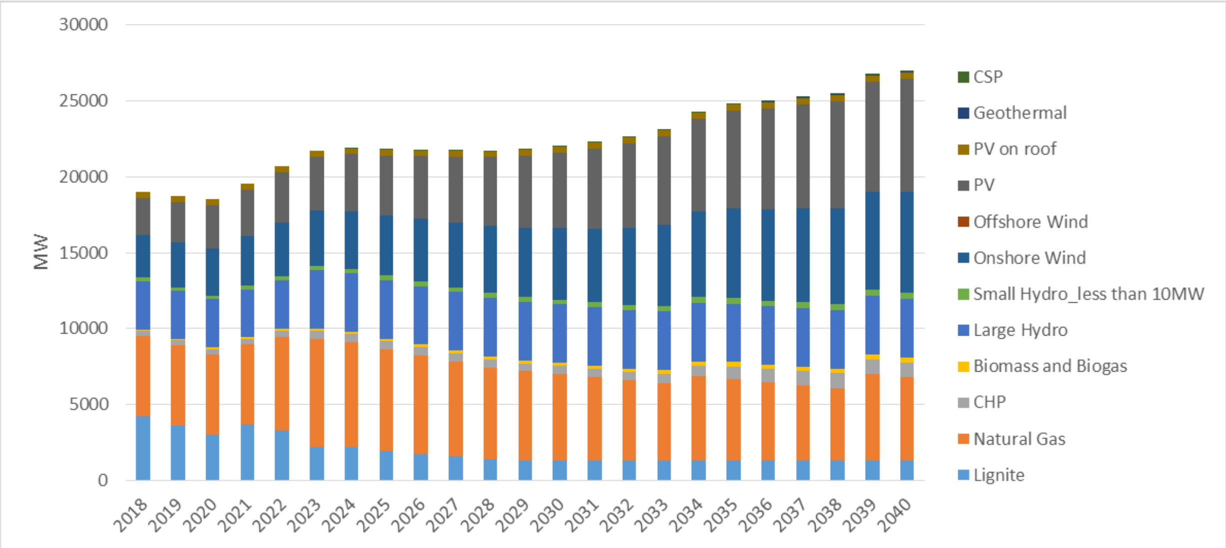


Figure 6.64: Evolution of the Greek Electricity Generation Mix – Extreme Demand Scenario.

As it is expected as the electricity demand increases so the total size of the power system's installed capacity is increased. However, in the low and in the reference demand scenarios the total size of the power system is at the same levels.

6.2.2 Production Mix – RES Share (%) – Electricity Imports Share (%)

The evolution of the electricity production mix as well as the RES and Electricity Imports Shares for each optimization approach are presented in the following figures.

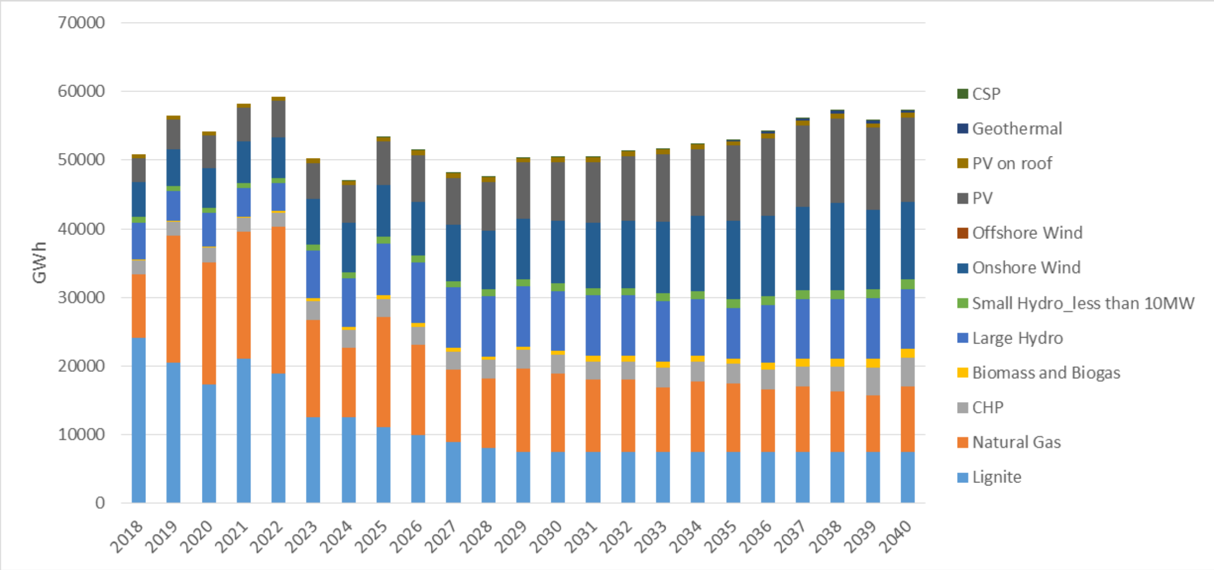


Figure 6.65: Evolution of the Greek Electricity Production Mix – Reference Demand Scenario

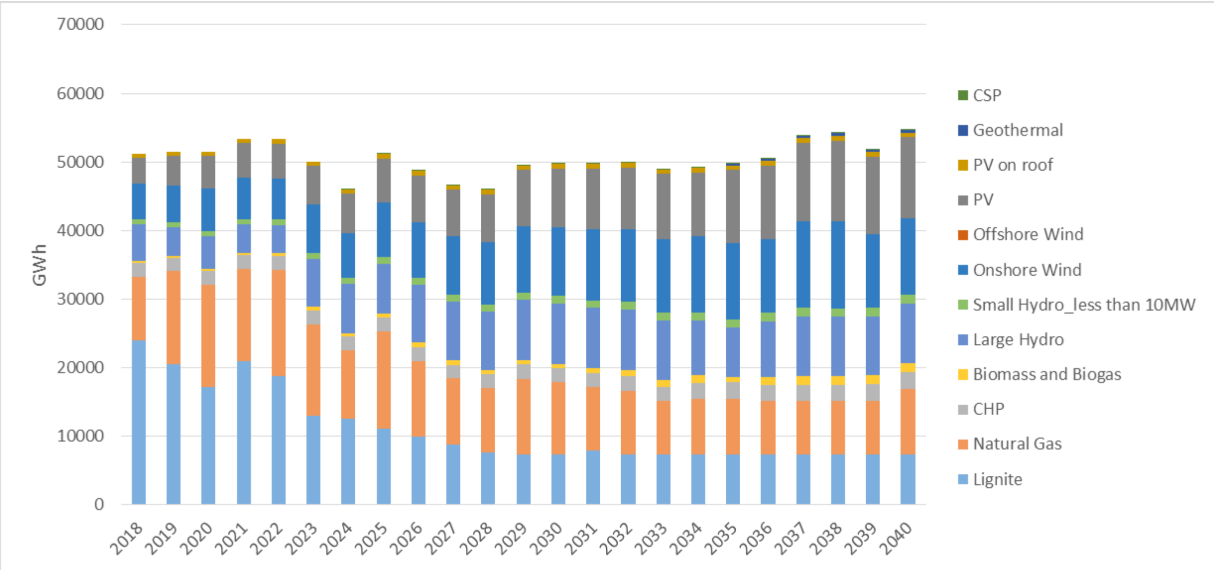


Figure 6.66: Evolution of the Greek Electricity Production Mix – Low Demand Scenario

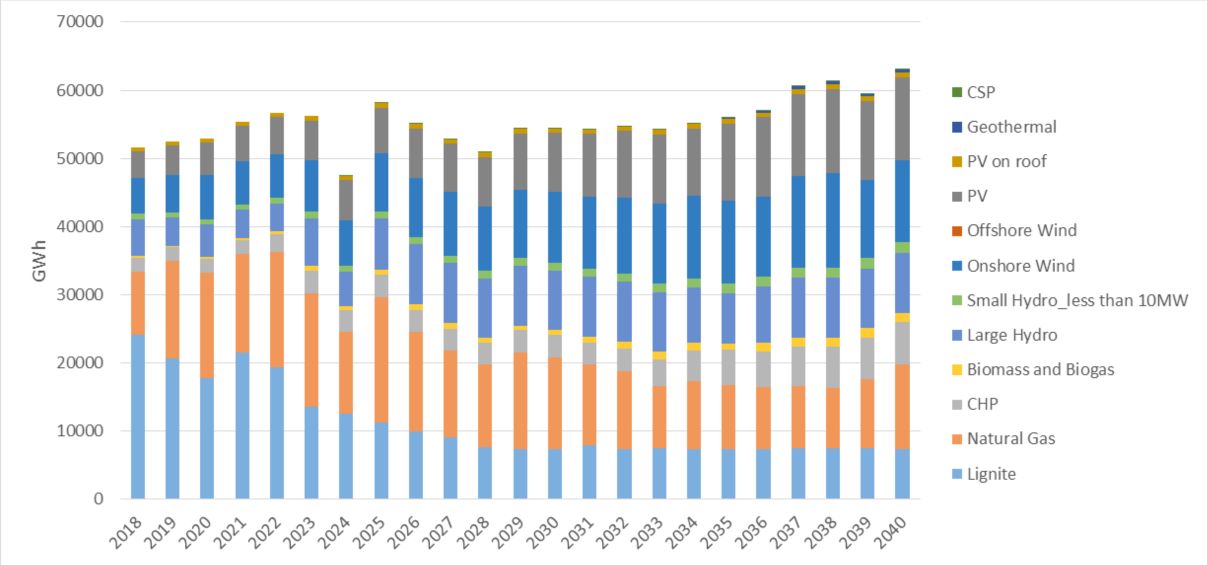
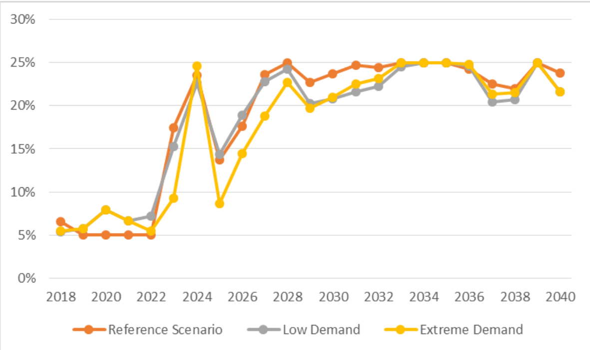


Figure 6.67: Evolution of the Greek Electricity Production Mix – Extreme Demand Scenario.

The evolution of the production mix is in line with the one of the generation mix. The production mix of the low demand's scenario and the one of the reference demand's are evolving similarly.



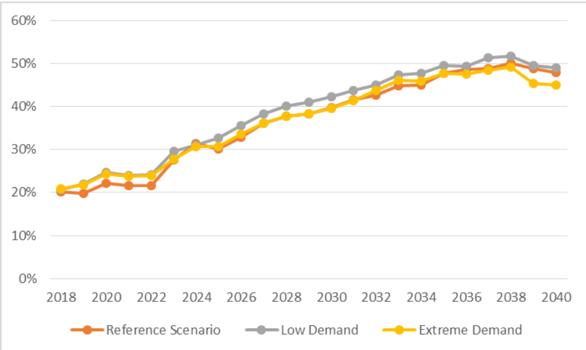


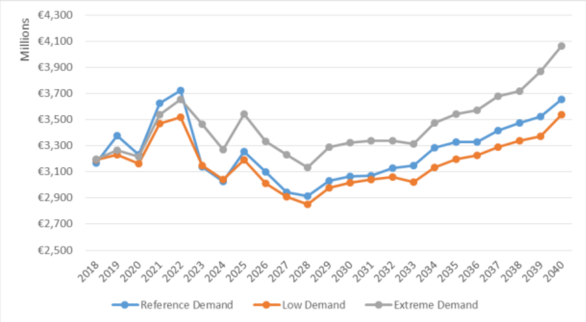
Figure 6.68 Annual Electricity Imports Share under different demand scenarios

Figure 6.69: RES Share under different demand scenarios

As far as the RES Shares is concerned, for every demand scenario, the maximum RES Share is in the vicinity of 50%. The electricity imports share, for most of the considered period, have relatively similar values.

6.2.3 Total Annualized Production Cost-LCOE

The evolution of the Total Annualised Production Cost, on an annual basis, as well as the LCOE's for each demand scenario are presented in the following figures.



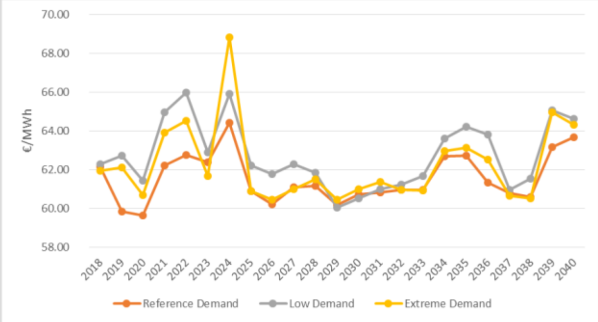


Figure 6.70: Annual TAPC under different demand scenarios

Figure 6.71: Annual LCOE under different demand scenarios

The annual TAPC as Figure 6.70 shows, is increased as the electricity demanded increases. Also the annual LCOE values, under different demand scenarios, have the same behavior.

The following figure gives an approximation of the cumulative TAPC for each examined demand scenario.

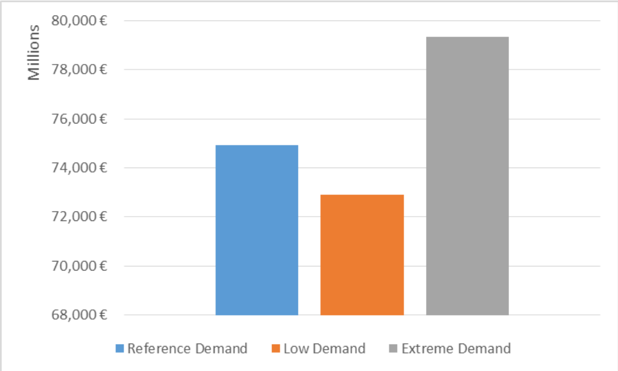


Figure 6.72: Cumulative TAPC under different demand scenarios.

As the above figure shows, the cumulative TAPC is increased as the electricity demand is increased.

6.2.4 Investments

The following figures examine the evolution of the annual investments as well as the cumulative investments and the cumulative investments in RES plants for the entire examined period, under different demand scenarios.

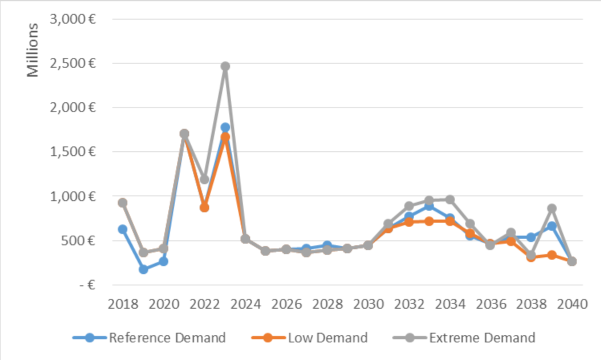


Figure 6.73: Annual Investments under different demand scenarios

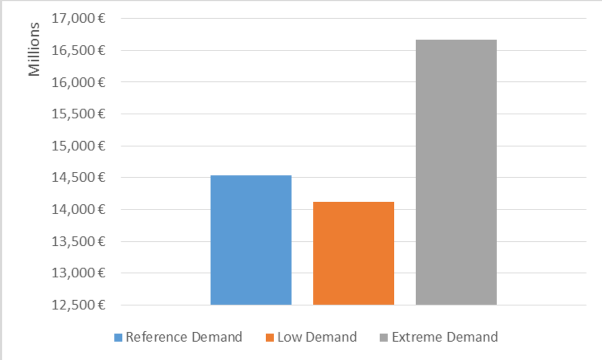


Figure 6.74: Cumulative Investments under different demand scenarios

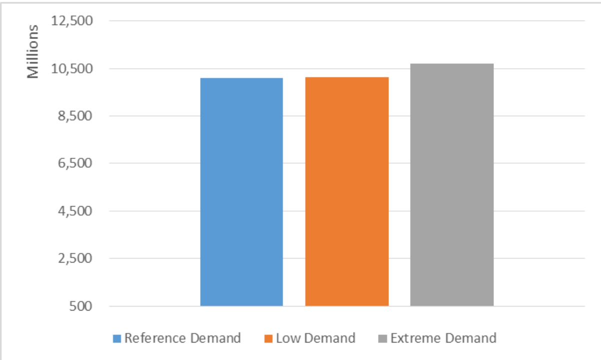


Figure 6.75: Cumulative RES Investments under different demand scenarios.

The level of the investment activity in RES technologies under the different demand scenarios have similar behaviour. Yet in year 2023, for the extreme demand scenario, a big investment in a Natural Gas Station is made, which leads to higher cumulative investments compared to the other two demand scenarios. In addition, the reference demand's scenario cumulative investments value, is close to the one of the low demand's scenario.

The cumulative investments in RES plants for each demand scenario are at the same levels.

6.2.5 Value Added

The cumulative value added for the different demand scenarios is presented in the following figure.

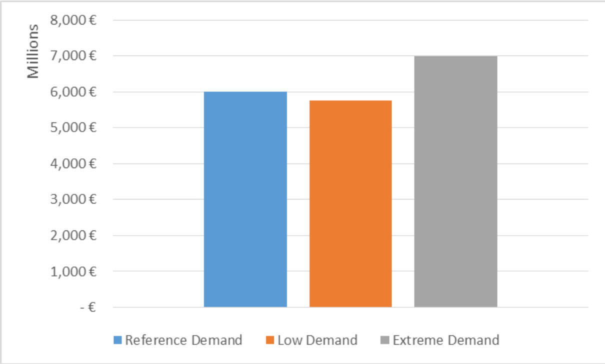


Figure 6.76: Cumulative Value Added under different demand scenarios.

In the reference and low demand scenario, the cumulative value added at the end of the examined period is in the same vicinity. As far as the extreme demand scenario is concerned, despite the fact that the cumulative investment activity is significantly higher than the one in the other demand scenarios, the fact that the cumulative investments in RES is at the same levels in comparison to the other demand scenarios and that the additional investment activity comes from a Natural Gas Station that has not an extremely high GVA multiplier, the cumulative value added is not increased exponentially.

6.2.6 Monetary Outflows

The cumulative ISEIC and Monetary Outflows for each demand scenario are presented as follows.

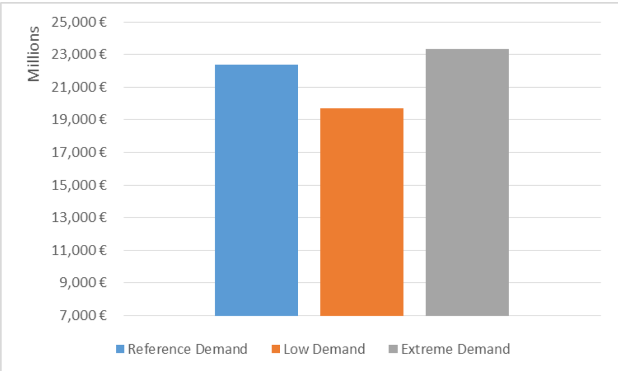


Figure 6.77: Cumulative ISEIC under different demand scenarios

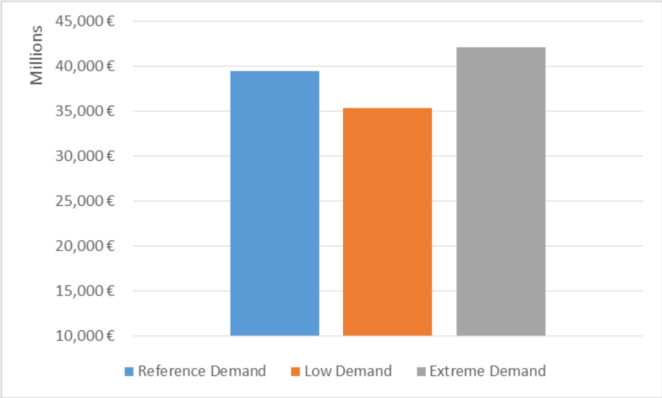


Figure 6.78: Cumulative Monetary Outflows under different demand scenarios

The cumulative ISEIC in the Extreme Demand scenario is around 2 billion € higher than the one in the reference scenario, due to the fact that the installed capacity of natural gas fired (See Section 6.1.2.i) is higher in this scenario than in the other ones. This has obviously an impact in the cumulative monetary outflows.

6.2.7 Employment Effects

The cumulative direct employment effects under each different examined demand scenario are presented as follows.

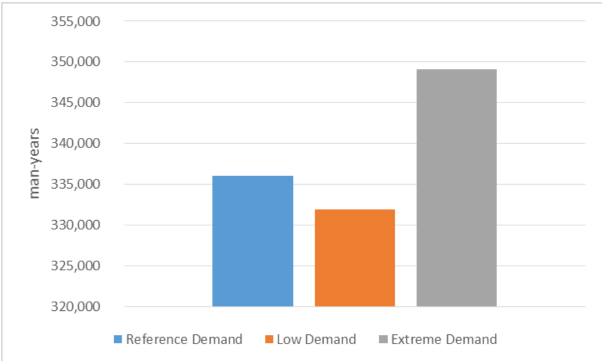


Figure 6.79: Cumulative Direct Employment under different demand scenarios

From the above figure, one can claim that the electricity demand has positive correlation with the direct employment effects.

6.2.8 Emissions

The evolution of the annual CO_2 emissions, for the different demand scenarios under consideration, is presented in the following figure.

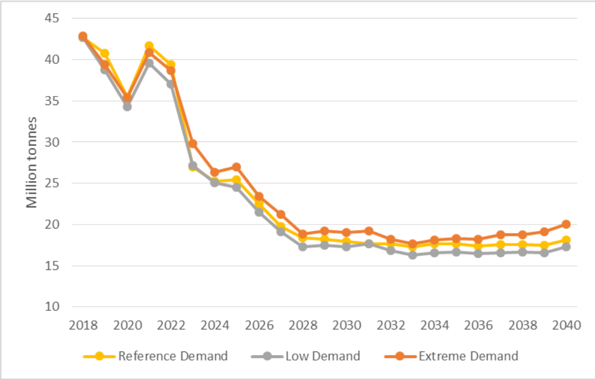


Figure 6.80: Annual CO_2 Emissions under different demand scenarios

Higher electricity demand is translated into higher CO_2 emissions.

6.2.9 Role of Natural Gas Stations under different demand scenarios

In this section the role of Natural Gas Stations in different demand scenarios is presented. The first indicative figures present the evolution of the Natural Gas stations installed capacity as well as their electricity production and capacity factor.

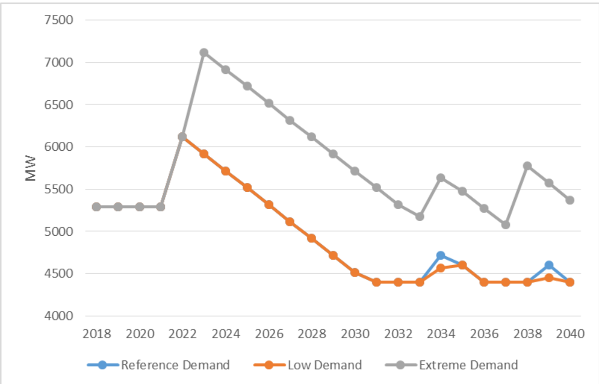


Figure 6.81: Evolution of Natural Gas Stations installed capacity under different demand scenarios

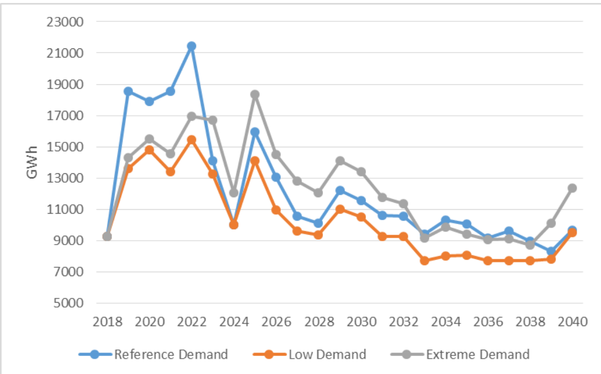


Figure 6.82: Evolution of Natural Gas Stations electricity generation under different demand scenarios

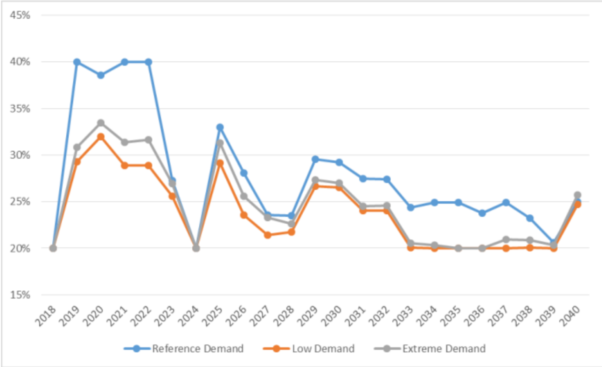


Figure 6.83: Natural Gas Stations Capacity Factor under different demand scenarios.

As far as the installed capacity is concerned, in year 2023 for the extreme demand scenario, a new investment in Natural Gas Stations in the vicinity of 1000 MW which is the maximum capacity addition value for this technology, is taking place. From this year and onwards, the installed capacity of Natural Gas Stations in each demand scenario is declining at the same rate, except some additions in the last examined years. This can be explained that as some of the natural gas stations capacity is decommissioning, the electricity imports shares are increasing in order to eliminate the deficit that will arise in the total electricity production. Despite this fact, it is obvious that as the demand is increasing, a part of this increased demand will be covered from new additions in natural gas stations.

In terms of energy production from the natural gas stations, for the biggest part of the examined period, it can be stated that as the electricity demand is increased, the total electricity generation from natural gas stations will be also increased. The Capacity Factors show relative low variation in the examined demand scenarios.

The following figures present the cumulative investment activity as well as the value added, attributed to natural gas stations.

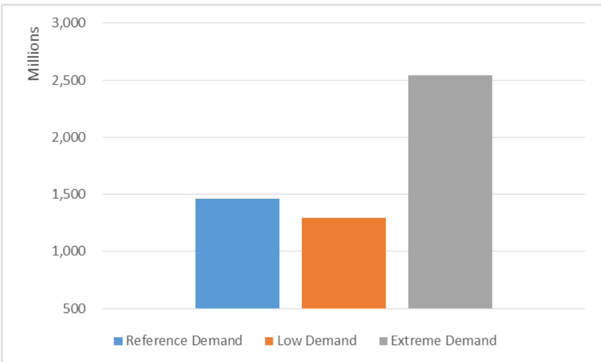


Figure 6.84: Cumulative Investments in Natural Gas Stations under different demand scenarios

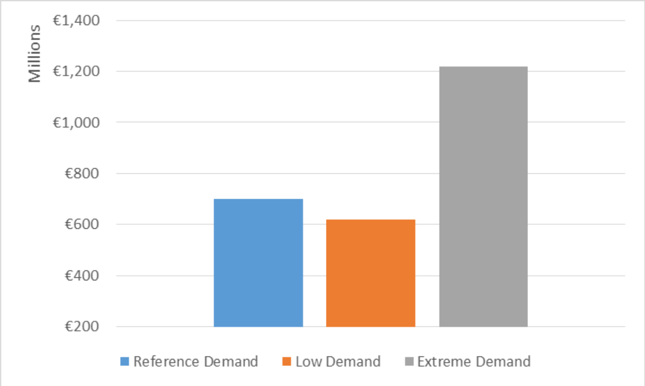


Figure 6.85: Cumulative Value Added from Natural Gas Stations under different demand scenarios.

Both cumulative values proved to have positive correlation with the electricity demand.

In the following figure, the cumulative direct employment effects from natural gas stations, examined for the different demand scenarios, are presented. It is obvious that electricity demand and direct employment from the operation and development of Natural Gas Stations are positively correlated.

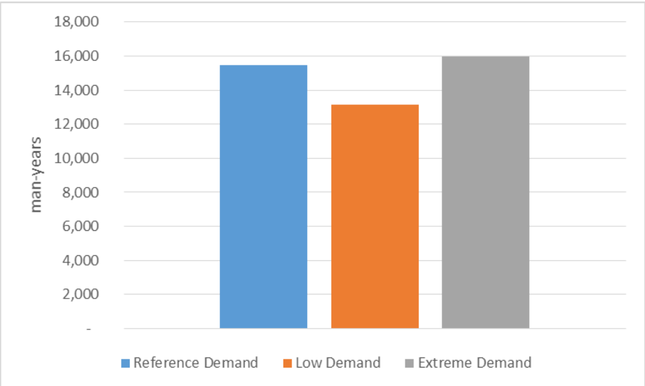


Figure 6.86: Direct Employment from Natural Gas Stations under different demand scenarios.

6.3 Penetration of Offshore Wind Technology

The results for the scenario regarding the penetration of offshore wind technology are presented and analyzed in the following sections.

6.3.1 Electricity Generation Mix (Installed Capacity) – Natural Gas Stations Capacity

The evolution of the Electricity Generation Mix in this scenario is presented in the following figure.

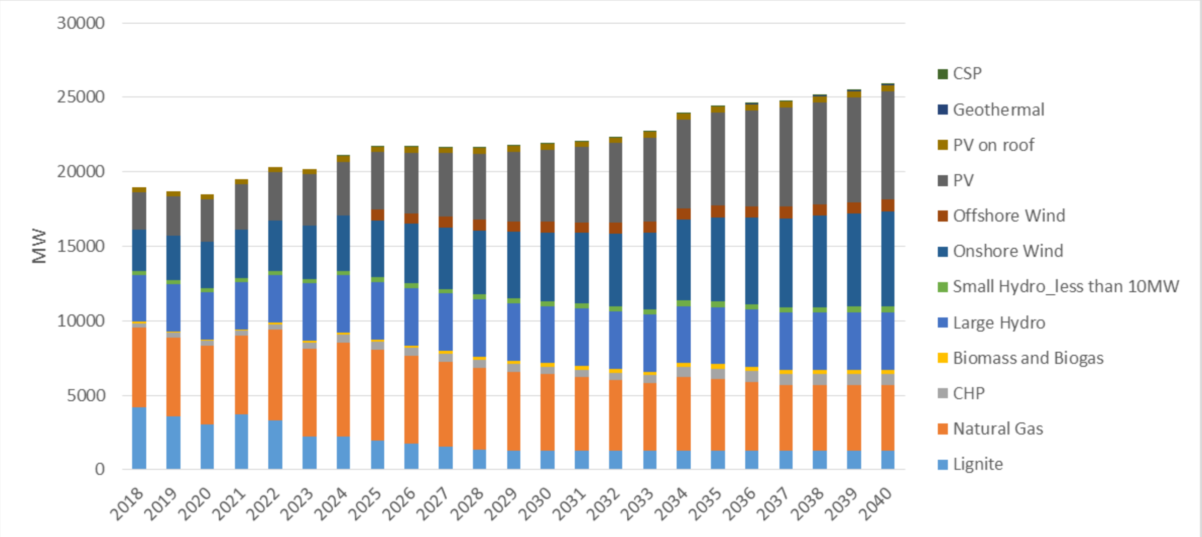


Figure 6.87: Evolution of the Greek Electricity Generation Mix – Penetration of Offshore Wind Energy Scenario

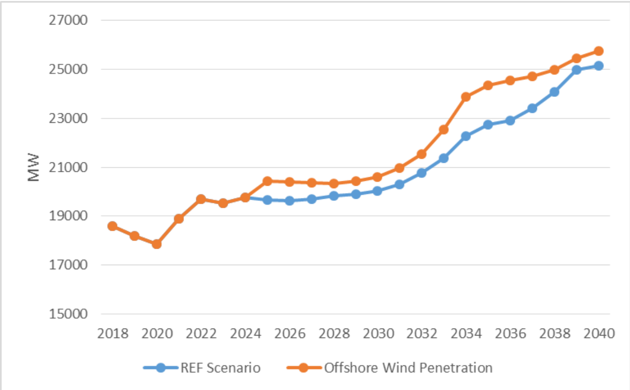


Figure 6.88: Evolution of Total Annual installed capacity – REF scenario and Offshore Wind Penetration Scenario

The first capacity addition of offshore wind farm, after the first one which is assumed to be in 2025, occurs in 2033 and it is in the vicinity of 50 MW. One more addition of 50 MW occurs the following year, and the resulted total annual capacity of offshore wind farms is equal to 816 MW. Also, the introduction of the offshore wind farms increase the total annual installed capacity.

The evolution of the Natural Gas Stations installed capacity, for the REF scenario and the examined one, is as follows.

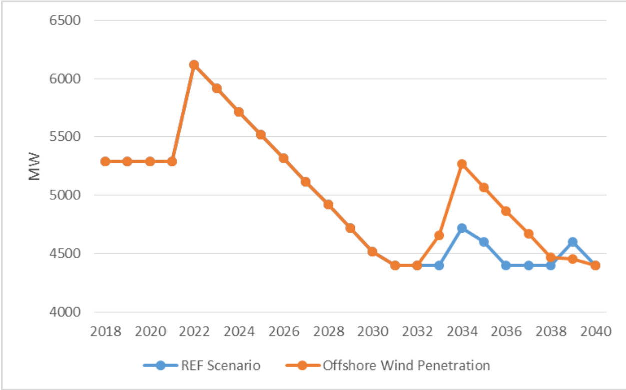


Figure 6.89: Evolution of Natural Gas Stations installed capacity – REF scenario and Offshore Wind Penetration Scenario

Taking into consideration the aforementioned capacity additions of offshore wind farms, it can be claimed that the new offshore capacity additions in 2033 and 2034 will come with capacity additions in the Natural Gas Stations, although after 2034 there is a decline in the installed capacity of Natural Gas Stations.

6.3.2 Production Mix – RES Share (%) – Imports Share (%)

The evolution of the total electricity generation from the introduction of offshore wind farms, in comparison to the REF scenario is presented as follows.

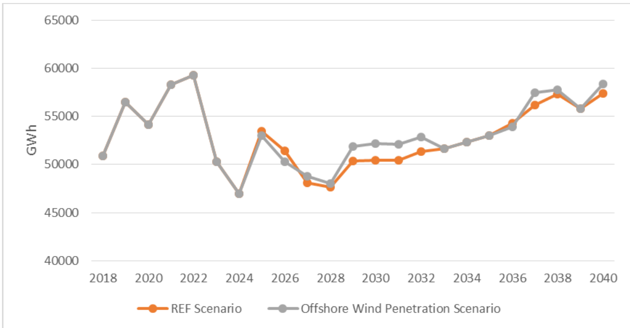


Figure 6.90: Evolution of Total Electricity Generation – REF scenario and Offshore Wind Penetration Scenario

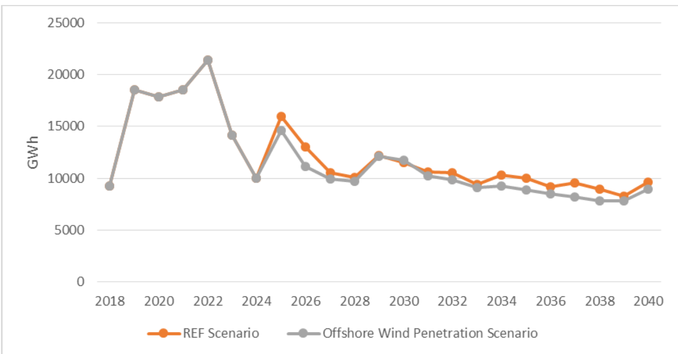
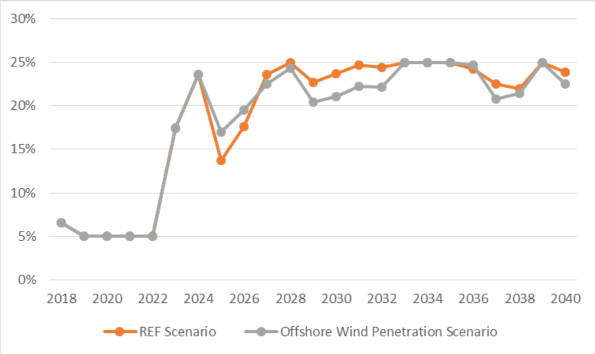


Figure 6.91: Evolution of Natural Gas Stations electricity generation – REF scenario and Offshore Wind Penetration Scenario



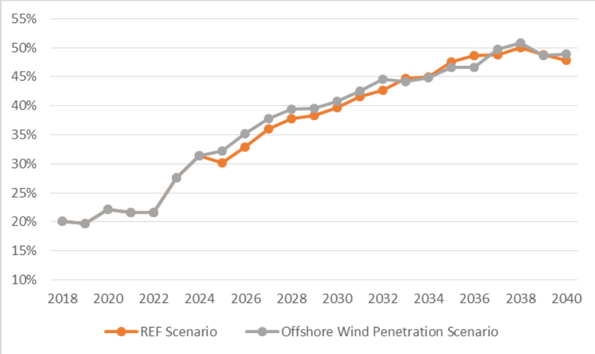


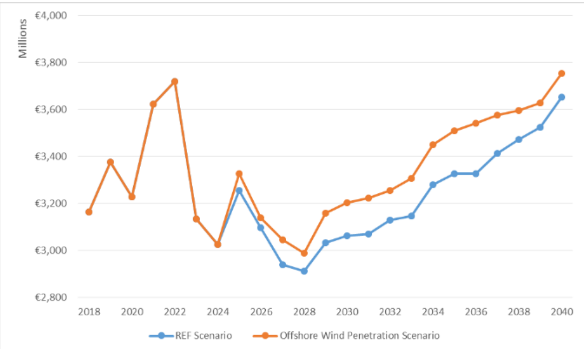
Figure 6.92 Annual Electricity Imports Share REF Scenario and Offshore Wind Penetration Scenario

Figure 6.93: RES Share - REF Scenario and Offshore Wind Penetration Scenario

By comparing these figures it can be stated that the introduction of offshore wind farms in the interconnected system will result to a minor reduction in the total electricity production (in some years) which will be stabilized by the increase in the electricity imports share. In addition, although the installed capacity of natural gas stations is increased from 2032 up to 2034, the electricity generation of these stations is remaining at a constant level, compared to the REF scenario results. Lastly, the RES Shares when the offshore wind farms are introduced in the interconnected system is increased, compared to the one of the REF scenario.

6.3.3 Total Annualized Production Cost-LCOE

The evolution of the TAPC and cumulative TAPC, for the REF scenario and the examined one are presented in the following figures.



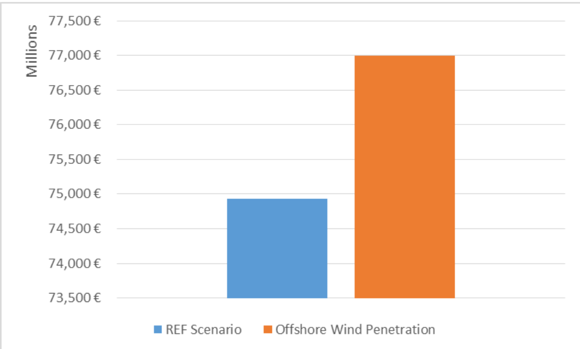


Figure 6.94: Annual TAPC – REF scenario and Offshore Wind Penetration Scenario

Figure 6.95: Cumulative TAPC – REF scenario and Offshore Wind Penetration Scenario

From the above figures it is obvious, that the penetration of offshore wind energy increases the annual TAPC as well as the cumulative one, compared to the REF scenario. This can be explained by the fact that the introduction of offshore wind farms does not lead to major capacity retirements.

The evolution of the annual LCOE for the REF scenario and the examined one are presented as follows.

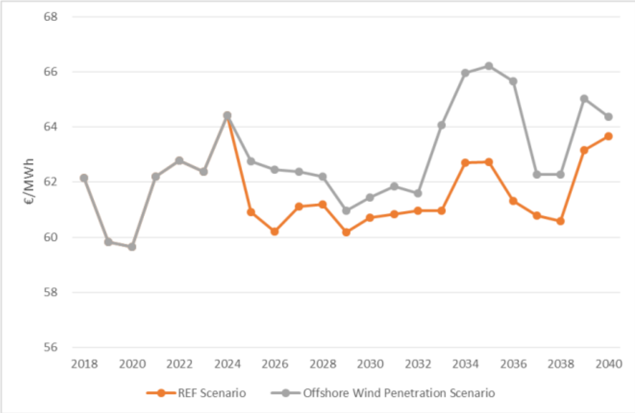


Figure 6.96: Annual LCOE – REF scenario and Offshore Wind Penetration Scenario

As a result of the increase in the annual TAPC, the LCOE is increased with the introduction of offshore wind farms.

6.3.4 *Investments – Value Added*

The cumulative total and in RES technologies investments as well as the value added in the REF scenario and in the examined scenario are presented in the following figures.

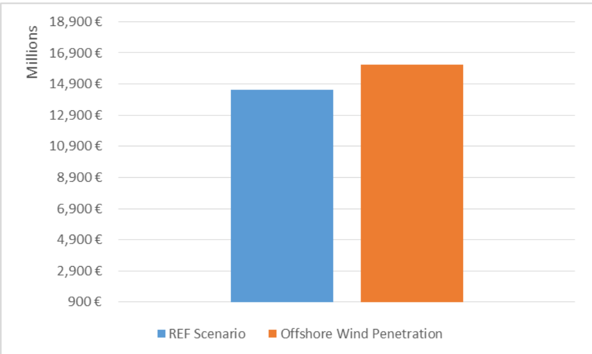


Figure 6.97: Cumulative Investments REF scenario and Offshore Wind Penetration Scenario

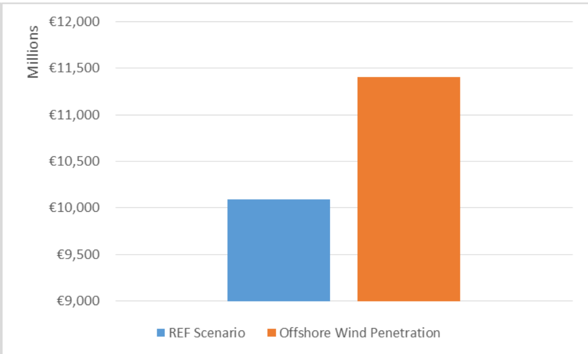


Figure 6.98: Cumulative RES Investments REF scenario and Offshore Wind Penetration Scenario

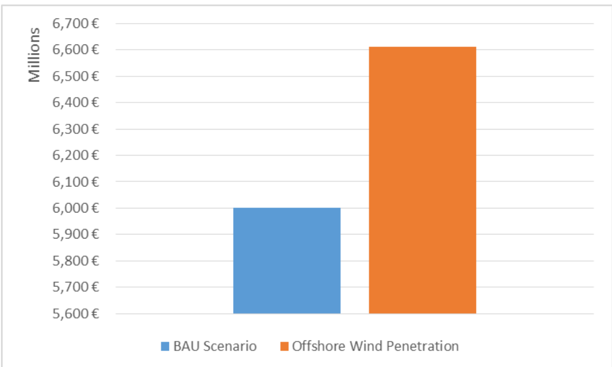


Figure 6.99: Cumulative Value Added - REF scenario and Offshore Wind Penetration Scenario

The cumulative total investment activity, the cumulative investments in RES technologies and the value added, are significantly increased with the penetration of offshore wind farms in the Greek interconnected system.

6.3.5 Monetary Outflows

The cumulative ISEIC and monetary outflows for the REF scenario and the examined one are presented in the following figures.

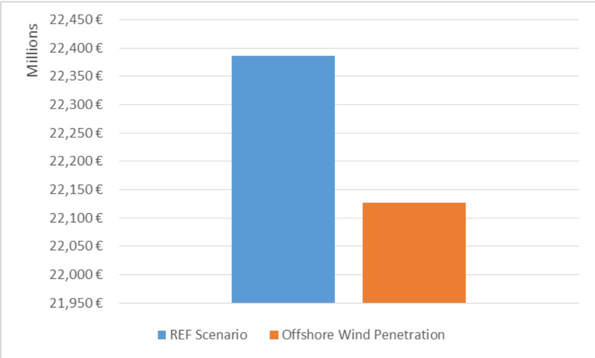


Figure 6.100: Cumulative ISEIC – REF scenario and Offshore Wind Penetration Scenario

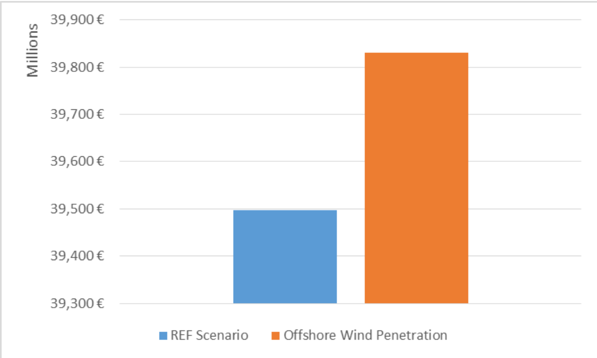


Figure 6.101: Cumulative Monetary Outflows- REF scenario and Offshore Wind Penetration Scenario

The reduction of the cumulative ISEIC in the offshore wind penetration scenario that is derived from Figure 6.100, can be attributed to the lower levels of electricity imports share in the latter scenario, in contrast to the same levels in the REF scenario. On the other hand, the investments in offshore wind farms will increase the cumulative monetary outflows compared to the REF scenario.

6.3.6 Employment Effects

The cumulative direct employment effects from the introduction of offshore wind farms in the Greek interconnected system compared to the REF scenario are presented in the following figure.

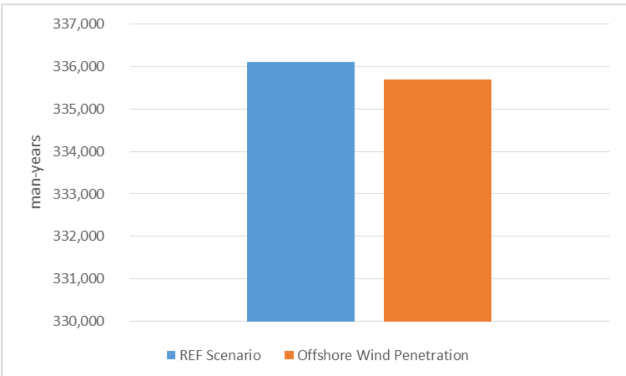


Figure 6.102: Cumulative Direct Employment - REF scenario and Offshore Wind Penetration Scenario

It is obvious that the cumulative direct employment in a scenario of offshore wind farms penetration, will not be increased compared to the REF scenario. This is explained by the fact that the introduction of offshore wind technology will reduce the rate of new PVs capacity additions (PVs have a high direct employment factor).

6.3.7 Emissions

The annual level of CO_2 emissions, from the introduction of offshore wind farms in the Greek interconnected system compared to the REF scenario are presented in the following figure.

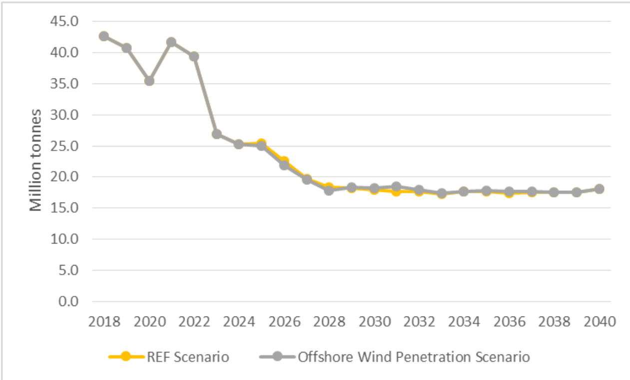


Figure 6.103: Annual CO_2 Emissions - REF scenario and Offshore Wind Penetration Scenario

It is obvious that there is no significant change in the annual CO_2 emissions in the two scenarios, as no major thermal plant retirement will take place in the offshore wind penetration scenario.

6.4 100% Decommission of Lignite Power Plants

In this section the results for the two different demand scenarios (IPTO's reference and extreme demand scenarios) regarding the 100% decommission of Lignite Power Plants in 2028 are being presented. In addition, a comparison between the REF scenario's data set outcomes, for the two different demand scenarios, as well as the current examined scenario's results is being conducted.

6.4.1 Electricity Generation Mix (Installed Capacity)

The evolution of the electricity generation mix, for the reference and extreme demand scenarios, with the 100% decommission of lignite plants in 2028 are presented as follows.

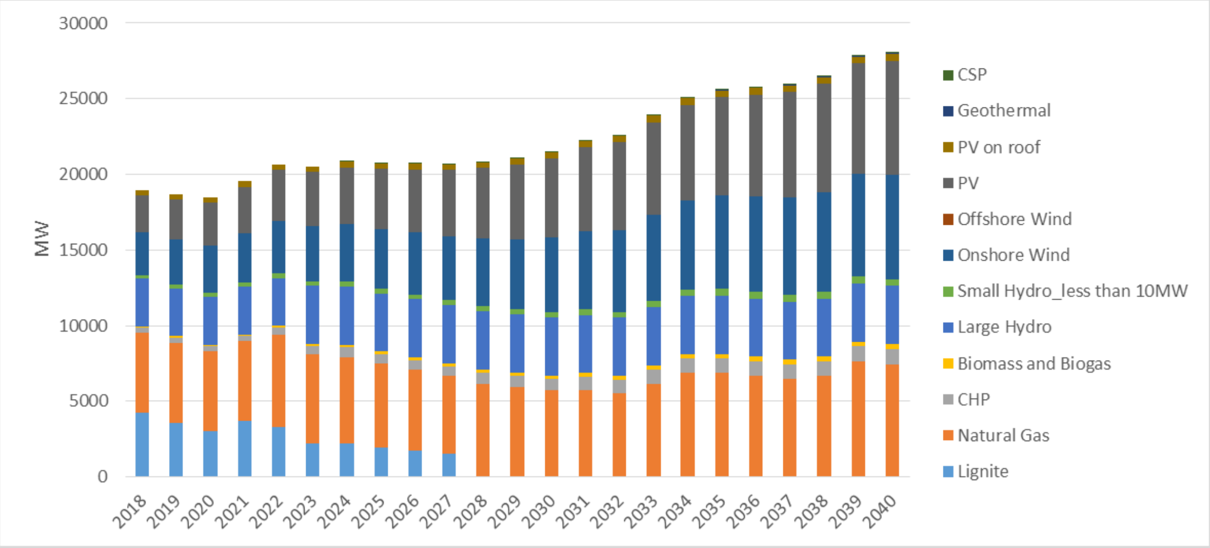


Figure 6.104: Evolution of the Greek Electricity Generation Mix – Reference Demand Scenario-100% lignite decommission

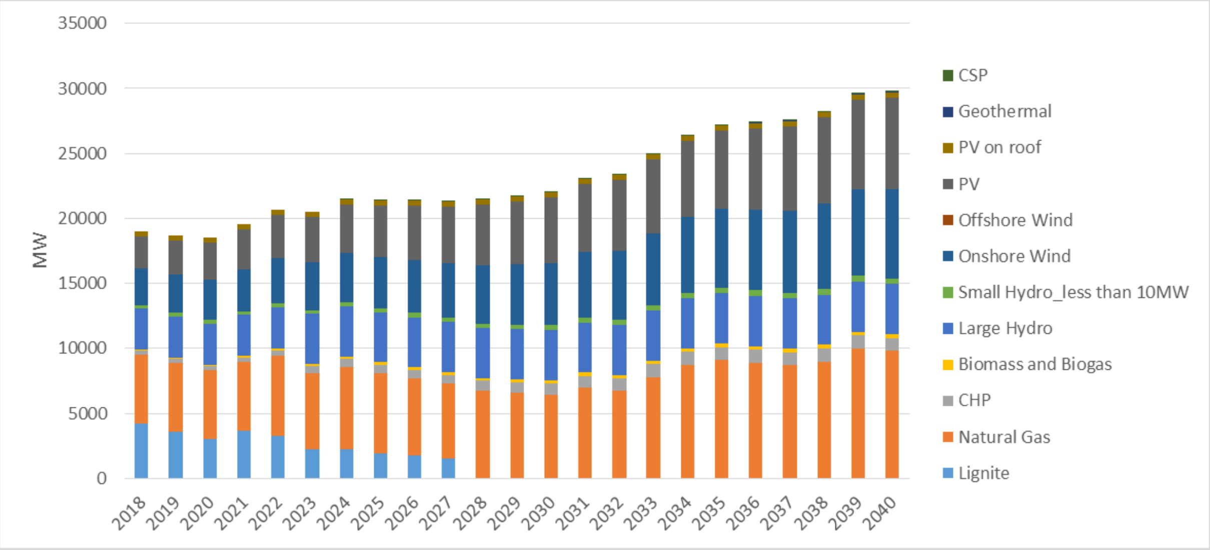


Figure 6.105: Evolution of the Greek Electricity Generation Mix – Extreme Demand Scenario-100% lignite decommission

In the extreme demand scenario, the total size of the Greek interconnected system is reaching 30GW.

As far as natural gas stations is concerned, the evolution of their installed capacity is shown in the next figure.

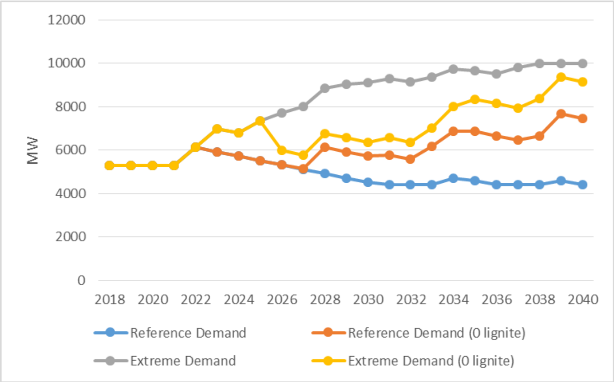


Figure 6.106: Evolution of Natural Gas Stations installed capacity – Reference and Extreme Demand Scenarios – 100 % lignite decommission

In the reference demand scenario, the installed capacity of natural gas stations is increased from 2028 and onwards where the 100% decommission of lignite plants is taking place. The total installed capacity in 2040 of natural gas stations is in the vicinity of 7800 MW.

On the other hand, in the extreme demand scenario, the increase in Natural Gas stations' installed capacity it is not immediate, following the 100% decommission of lignite power plants. Despite this fact, an increase in the installed capacity from 2032 and onwards is observed.

6.4.2 Production Mix – RES Share (%) – Imports Share (%)

The evolution of the electricity production mix, for the reference and extreme demand scenarios, with the 100% decommission of lignite plants in 2028 are presented as follows.

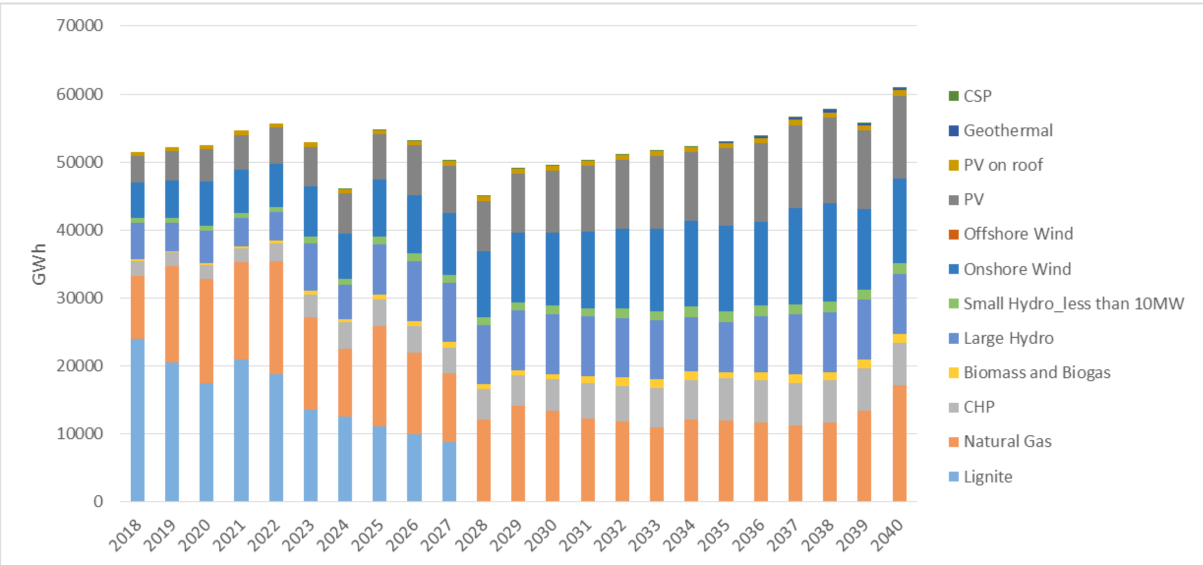


Figure 6.107: Evolution of the Greek Electricity Production Mix – Reference Demand Scenario - 100% lignite decommission

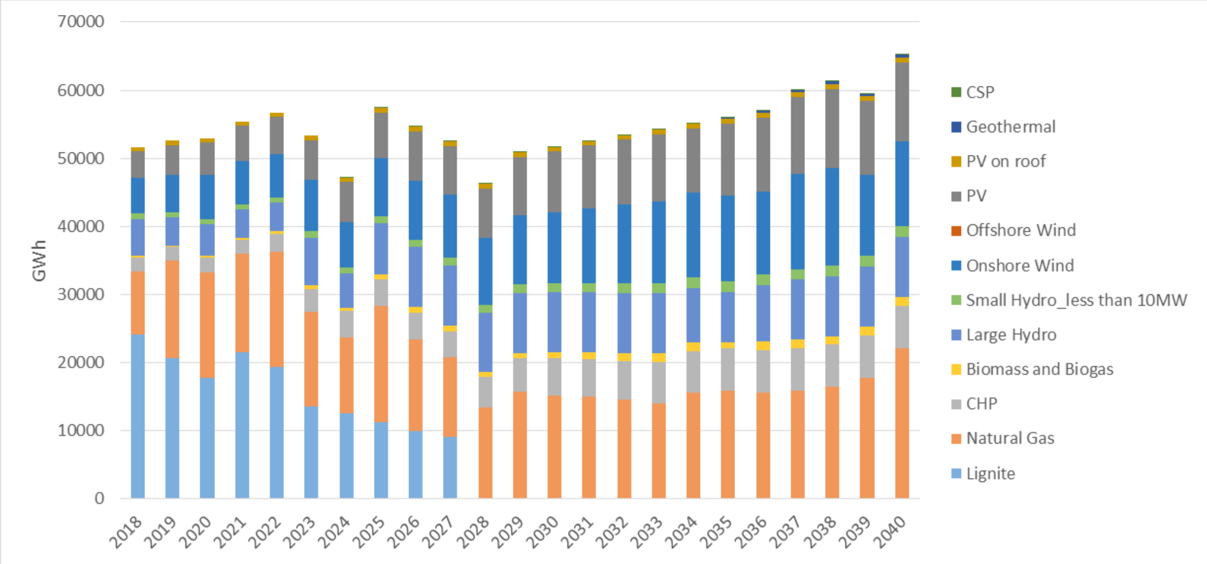


Figure 6.108: Evolution of the Greek Electricity Production Mix – Extreme Demand Scenario - 100% lignite decommission

Decommissioning lignite power plants in 2028 creates a reduction in the total domestic electricity production. This production gap will be covered in year 2028 by the increased production of Natural Gas Station as well as by the increased electricity imports share, as the following figures show. The following figures shows the evolution of the total domestic electricity production, for each demand scenario in contrast to the REF scenario results.

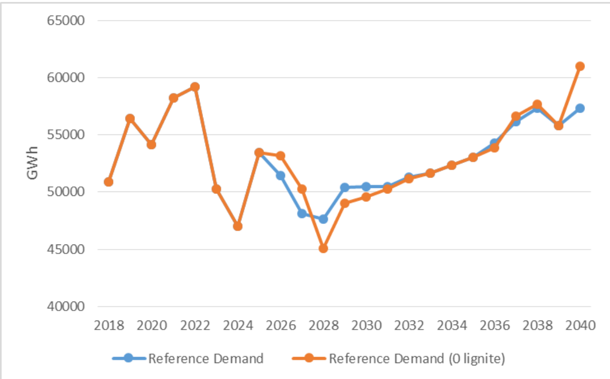


Figure 6.109: Evolution of Total Electricity Generation – Reference Demand scenario – REF scenario and 100% lignite decommission

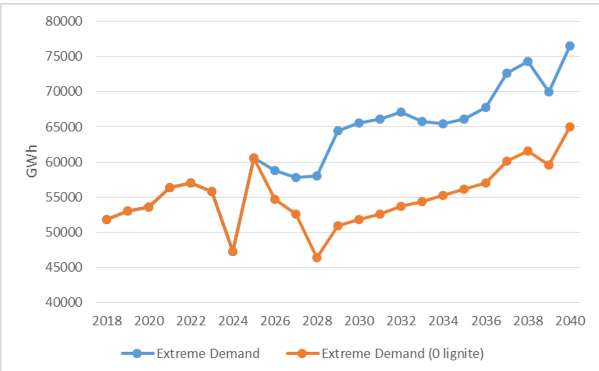


Figure 6.110: Evolution of Total Electricity Generation – Extreme Demand scenario – REF scenario and 100% lignite decommission

It can be claimed that in the reference demand scenario despite the decommission of the lignite power plants the level of the domestic electricity production will not be significantly affected. On the other hand, in the extreme demand scenario, it is observed a decline in the total domestic electricity production in the case of the 100% decommission of lignite power plants. This is an indicator that the electricity imports share will be increased so as the shortage in the domestic comparison that will be created due to the decommission of lignite power plants, to be eliminated.

The next figures shows the evolution of the electricity production in the Natural Gas Stations in each demand scenario.

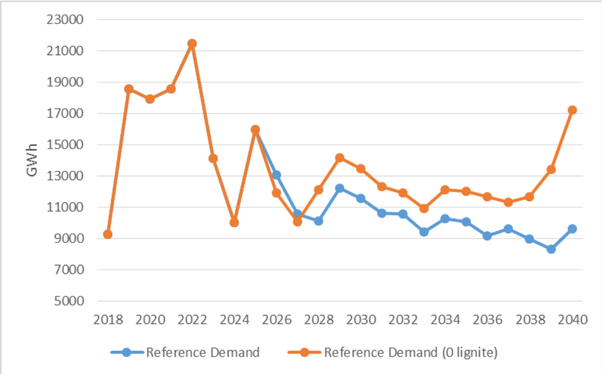


Figure 6.111: Evolution of Natural Gas Stations electricity generation – Reference Demand scenario – REF scenario and 100% lignite decommission

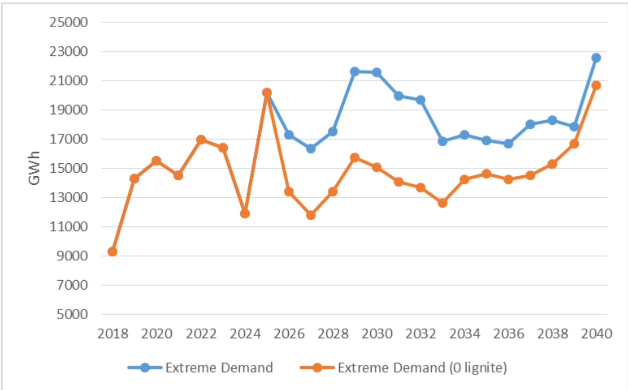
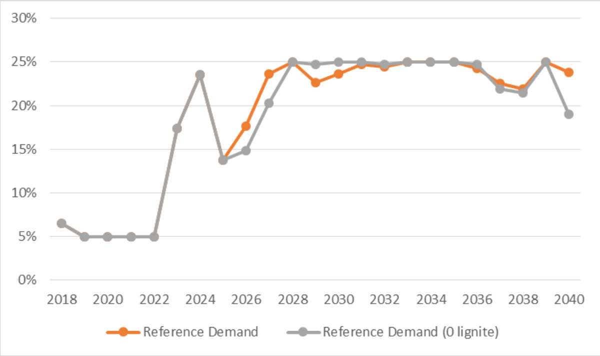


Figure 6.112: Evolution of Natural Gas Stations electricity generation – Extreme Demand scenario – REF scenario and 100% lignite decommission

In the reference demand scenario, the electricity production of Natural Gas Stations will be increased after the decommission of lignite power plants. As far as the extreme demand scenario is concerned, prior to 2028, a downward trend in the total electricity production from Natural Gas Stations is observed. However, from 2028 and onwards an immediate increase in their production is occurred, which means that the shortage in production created by the sudden decommission of lignite power plants will be dealt with an increase in Natural Gas Stations' production.

The following figures presents the evolution of the annual electricity imports share for the two examined demand scenarios.



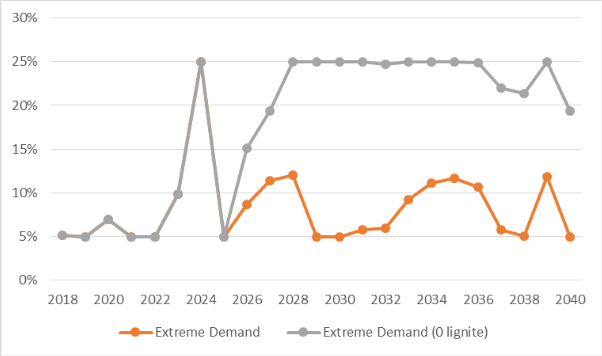


Figure 6.113 Annual Electricity Imports Share Reference Demand Scenario REF and 100% lignite decommission

Figure 6.114 Annual Electricity Imports Share Extreme Demand Scenario REF and 100% lignite decommission

In the reference demand scenario, it is obvious that in the REF scenario and in the 100% lignite decommission there is a convergence in the evolution of the annual electricity imports share. On the other hand, in the extreme demand scenario case, the 100% decommission of lignite plants will cause an increase in the annual electricity imports share.

6.4.3 Total Annualized Production Cost-LCOE

The cumulative TAPC, for the two examined demand scenarios, in the case of the REF scenario and the 100% decommission of lignite power plants, is presented in the following figures.

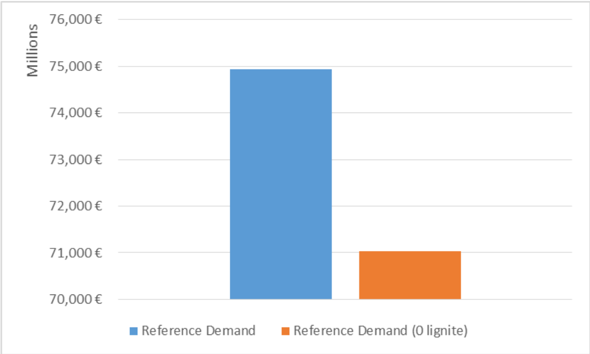


Figure 6.115: Cumulative TAPC - Reference Demand Scenario - REF scenario and 100% lignite decommission

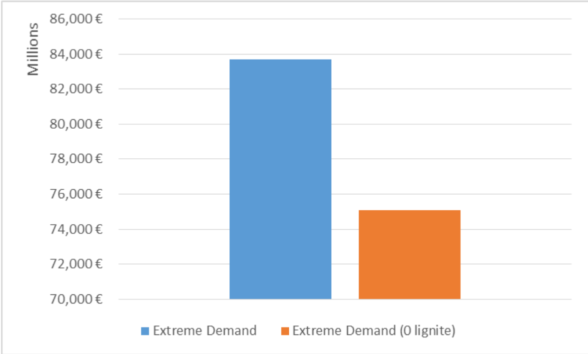


Figure 6.116: Cumulative TAPC - Extreme Demand Scenario - REF scenario and 100% lignite decommission

It is undeniable that in both demand scenarios the decommission of lignite power plants will reduce significantly the cumulative TAPC at the end of the examined period. This will also be reflected in the evolution of the LCOE which is presented in the following figures.

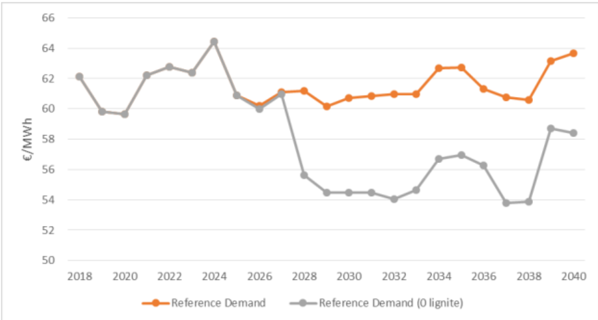


Figure 6.117: Annual LCOE – Reference Demand Scenario - REF scenario and 100% lignite decommission

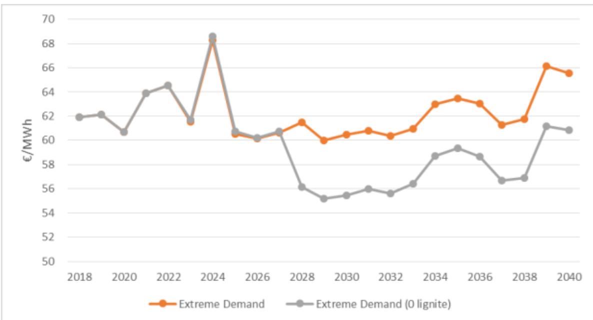


Figure 6.118: Annual LCOE – Extreme Demand Scenario - REF scenario and 100% lignite decommission

In both demand scenarios, the decommission in 2028 of the entire lignite power capacity will create a significant reduction in the LCOE. This a clear sign that the operation of lignite plants is increasing the overall cost of the power system.

6.4.4 Investments – Value Added

The following figures present the cumulative investment activity and value added for the two examined demand scenarios, by comparing the results from the REF and the 100% lignite decommission scenarios.

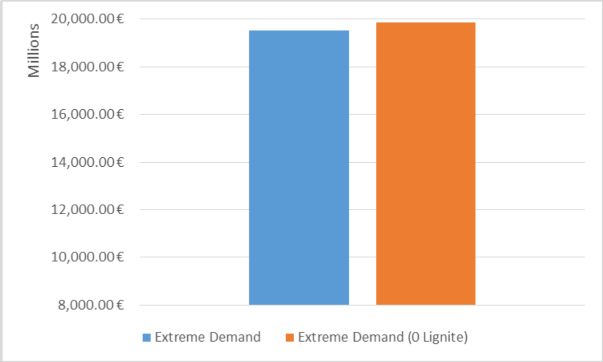
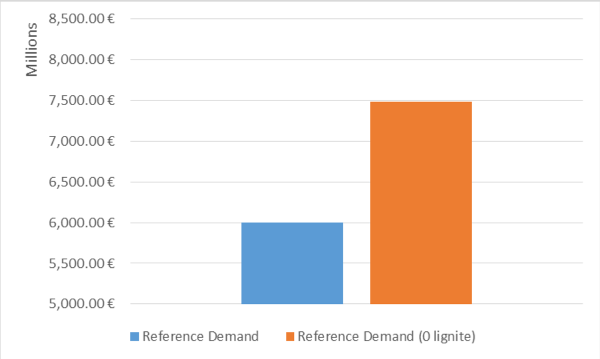


Figure 6.119: Cumulative Investments
Reference Demand scenario
REF scenario and 100% lignite decommission

Figure 6.120: Cumulative Investments
Extreme Demand scenario
REF scenario and 100% lignite decommission

In the reference demand scenario, the 100% decommission of lignite power plants will increase the cumulative investments as a significant increase in the natural gas stations' installed capacity will be observed. On the other hand, in the extreme demand scenario, the increase of the annual electricity imports share and the slower rate of growth regarding the Natural Gas Stations' installed capacity, do not increase significantly the cumulative level of total investments.



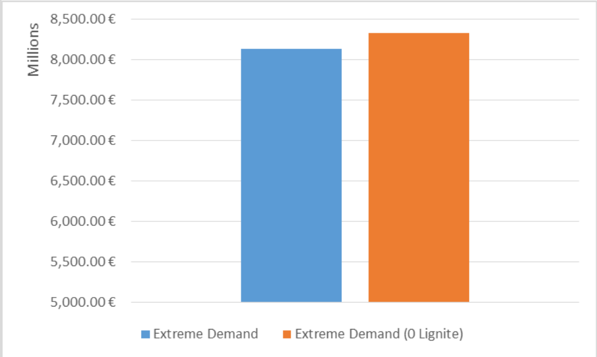


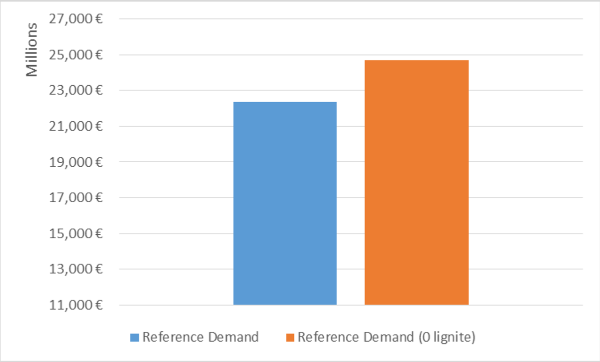
Figure 6.121: Cumulative Value Added
Reference Demand scenario
REF scenario and 100% lignite decommission

Figure 6.122: Cumulative Value Added
Extreme Demand scenario
REF scenario and 100% lignite decommission

The cumulative value added results have the same behavior as the ones of the cumulative investments.

6.4.5 *Monetary Outflows*

The cumulative ISEIC and monetary outflows, for each examined demand scenario and in comparison between the REF scenario and the 100% lignite decommission scenario are presented in the following figures.



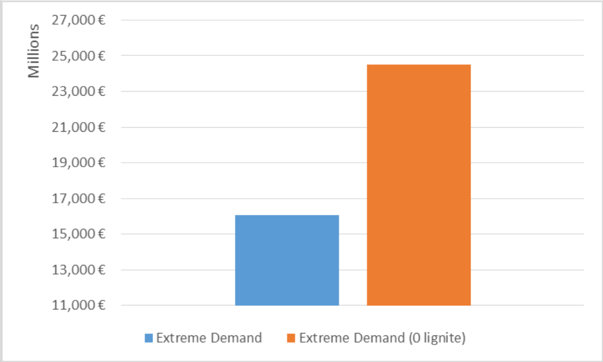
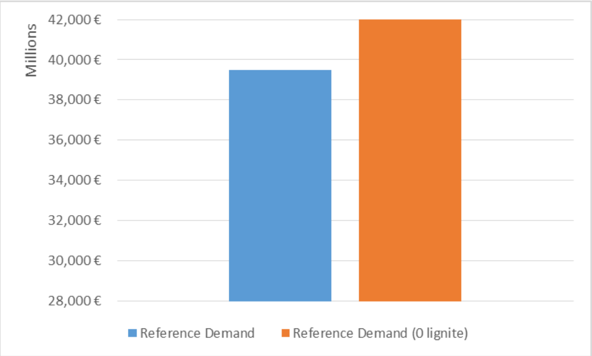


Figure 6.123: Cumulative ISEIC – Reference Demand scenario - REF scenario and 100% lignite decommission

Figure 6.124: Cumulative ISEIC - Extreme Demand scenario - REF scenario and 100% lignite decommission



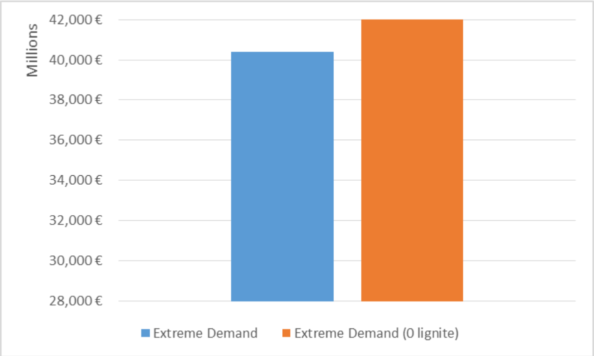


Figure 6.125: Cumulative Monetary Outflows Reference Demand scenario REF scenario and 100% lignite decommission

Figure 6.126: Cumulative Monetary Outflows Extreme Demand scenario REF scenario and 100% lignite decommission

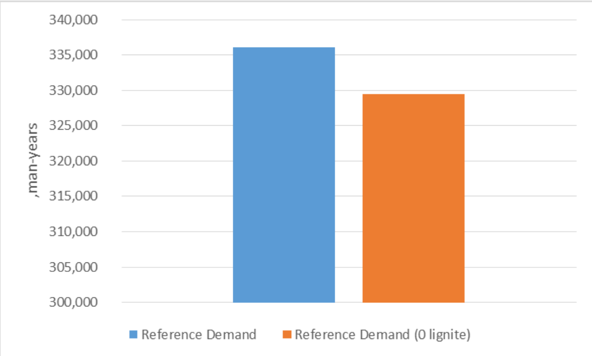
Regarding the cumulative ISEIC in the reference demand scenario, the increase in the electricity production of Natural Gas Stations' in the 100% lignite decommission case, causes an increase in the cumulative ISEIC.

On the other hand, in the extreme demand scenario, the lower level of Natural Gas Stations' electricity production but in the same time the higher level of electricity imports, compared to the REF Scenario, increases the cumulative ISEIC in the 100% lignite decommission scenario compared to the one of the REF scenario.

As far as the cumulative monetary outflows is concerned, in both demand scenarios, the results are following the trends are the same as the ones regarding the cumulative ISEIC.

6.4.6 Employment Effects

The next figures present the direct employment effects, in each demand scenario, by comparing the results of the REF and the 100% decommission of lignite power plants scenarios.



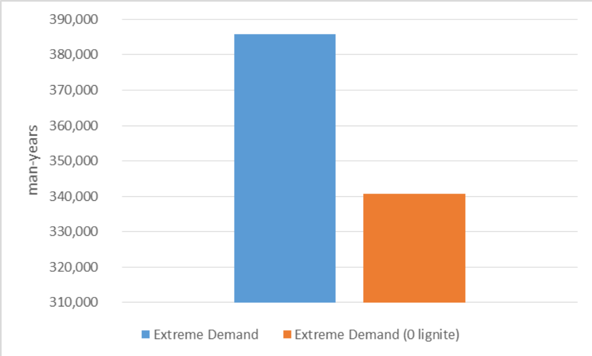


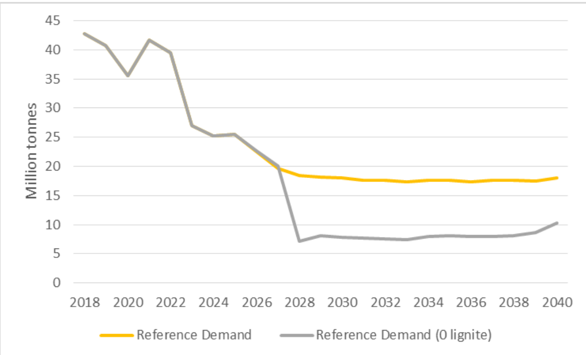
Figure 6.127: Cumulative Direct Employment Reference Demand scenario - REF scenario and 100% lignite decommission

Figure 6.128: Cumulative Direct Employment - Extreme Demand scenario - REF scenario and 100% lignite decommission

It can be stated, that in both demand scenarios the decommission of lignite power plants will reduce power system's cumulative direct employment effects, as the lignite power plants have a high direct employment effect (man-year per TWh of electricity produced).

6.4.7 Emissions

The next figures present the evolution of the annual CO_2 emissions generated by the entire power system, in each demand scenario, by comparing the results of the REF and the 100% decommission of lignite power plants scenarios.



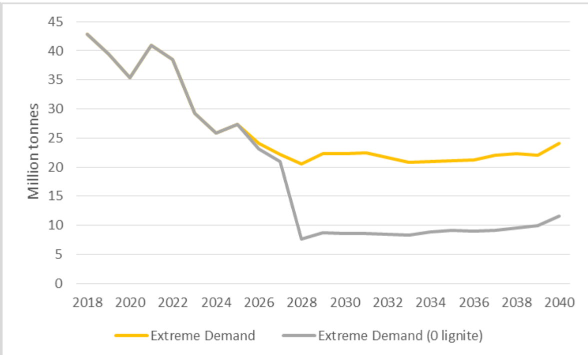


Figure 6.129: Annual CO_2 Emissions Reference Demand scenario REF scenario and 100% lignite decommission

Figure 6.130: Annual CO_2 Emissions Extreme Demand scenario REF scenario and 100% lignite decommission

Undeniably, the decommission in 2028 of the entire lignite power plants in Greece will reduce significantly the annual CO_2 emissions generated by the entire power system in Greece.

6.5 Summary-conclusions

In this chapter, the results of the four scenarios that were defined in Chapter 5 were presented. The basic elements that describe the evolution of the Greek power system, in the different demand scenarios, such as the generation-production mix, the level of investment activity, the added value, the monetary outflows, the employment effects and the CO_2 emissions were described and quantified.

7 Conclusion-Remarks

Methods for assessing the evolution of the Greek Interconnected electricity system have been examined. An openly available detailed software package has been studied and used. Then, a simplified model was built from scratch, employing the tools offered by a widely used computational package (Microsoft Excel).

The purpose of the work was not to derive quantitative results but rather to set up a procedure for analyzing and then evaluating scenarios regarding the system's evolution. Collecting and organizing data needed, was a significant part of the effort. Establishing different criteria and scenarios for assessing future evolution was another aspect of the work.

The achievements of this work can be summarized below.

- A literature review regarding the energy system modelling was conducted. The basic structure of energy systems models and how they are related to power system's expansion studies was investigated.
- The collection of the data that describe the Greek Power system was presented. Historical-Current's period data were collected. Projections regarding the evolution of the elements of the Greek power system that are utilized in order to optimize the evolution of it were also presented.
- The introduction of the optimization approaches and the validation of them by comparing them with different models-studies was presented. The four optimization approaches that were introduced in this thesis were: the minimization of the total annualized production cost, the maximization of the investment activity, the maximization of the added value and the minimization of monetary outflows. The proposed time-period of optimization was 3-years.
- Alternative scenarios regarding the evolution of the Greek Power System were introduced. The first was a Reference scenario were the different optimization approaches were applied and compared. The second scenario examined the evolution of the Greek Power System in different electricity demand scenarios. This scenario focused also on the role of the Natural Gas Stations. The third scenario investigated the introduction of offshore wind farms in the interconnected system. The fourth and last scenario dealt with the issue of decommissioning the entire lignite installed capacity in 2028.

The approaches followed with simplified model have certain assumptions and limitations, which were enumerated in detail in section 4.3. Some of them are rather arbitrary and they could have a significant influence on the reliability of the results obtained. Example of such assumptions are the constant electricity imports price for the entire examined period, the values of the maximum-minimum installed capacity and capacity additions of each technology constituting the Greek Power System, exports of electricity and the non-discounted monetary values in the investments, value added and monetary outflows results.

In summary, the quantitative conclusions derived from the simplified model should be considered with caution, in view of all assumptions made.

The major contribution of the thesis is thus the creation of an extended data set and an analysis procedure, that open the way for development of more accurate models, that could produce results with reliability, sufficient to be used for realistic estimations of possible evolution scenarios.

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9 Annexe-I

9.1 Capital Cost Projections

9.1.1 DIW Capital Cost Projections

Data from the German Institute for Economic Research (DIW Berlin) [45] that have been utilized in order to calculate annualized capital cost reduction rates are the following ones.

	Capital Cost in 2010 $/kW						
	2010	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Onshore Wind	1300	1269	1240	1210	1182	1154	1127
Offshore Wind	3000	2868	2742	2621	2506	2396	2290
PV	1560	950	750	675	600	555	472
CSP	3500	3154	2841	2560	2307	2078	1872
Biomass	2500	2424	2350	2278	2209	2141	2076
Geothermal	4200	3982	3775	3578	3392	3216	3049
Large Hydro	2000	2000	2000	2000	2000	2000	2000
Run-of-river (Small hydro)	3000	3000	3000	3000	3000	3000	3000
Lignite	1500	1500	1500	1500	1500	1500	1500
Gas CC	1400	1384	1367	1352	1337	1322	1308

Table 10.1: Evolution of Capital Costs [45]

9.1.2 Greek Power System Capital Cost Projections

By applying the capital cost reduction rates presented in Section 3.2.6.1., the capital costs that have been applied in this thesis are the following.

	Capital Cost in 2017 €/kW				
Technology	2020	2025	2030	2035	2040
Lignite	2075	2075	2075	2075	2075
Natural Gas	690	665	640	640	640
CHP	1110	1056	1004	955	908
Biomass and Biogas	1469	1425	1382	1340	1300
Large Hydro	2000	2000	2000	2000	2000
Small Hydro_less than 10MW	2396	2338	2280	2280	2280
Onshore Wind	1041	1017	993	970	948
Offshore Wind	1928	1845	1765	1689	1616
PV	610	548	548	516	443
PV on roof	1364	1225	1225	1154	991
Geothermal	1708	1624	1544	1469	1397
CSP	3388	3388	3388	3388	3388

Table 10.2: Evolution of Capital Costs of the Greek Power System technologies