Universidade do Minho
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Strategic Planning of Electricity Systems: Integrating Renewable Energies

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Tese de Doutoramento
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March, 2015

STATEMENT OF INTEGRITY

I hereby declare having conducted my thesis with integrity. I confirm that I have not used plagiarism or any form of falsification of results in the process of the thesis elaboration.

I further declare that I have fully acknowledged the Code of Ethical Conduct of the University of Minho.

University of Minho, 27th March 2015

Full name: Sérgio Lima Barroso Pereira

Signature:

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Abstract

The decision making process applied to the energy sector, particularly to the electricity sector, is complex and frequently requires the use of optimization models to deal with problems in the scope of electricity planning. The continuous growth of renewable energy sources (RES) to generate electricity became sustainable over the last years. This growth is justified by the increasing concerns related to the security of supply, the reduction of external energy dependency of most European countries, including Portugal, and the reduction of greenhouse gases emissions. Despite of the RES benefits, their integration is characterized by the difficulties on forecasting and variable electricity output. These difficulties bring considerable challenges to the electricity system management and to its planning.

This work is focused on the assessment of the RES impacts on the electricity system and on its integration in the long and short-term electricity planning. The main goals of this work are to analyse in which way the growth of RES can affect the electricity system and its power plants, and also to propose new optimization models for the strategic planning of the electricity system, which are able to recognize and include RES impacts. This will provide the decision maker with tools that will support the design of long-term scenarios for the electricity sector.

According to the outlined goals, four different optimization models were developed. All models were tested for a mixed hydro-thermal-wind power system, with characteristics close to the Portuguese one. The first one was proposed for the long-term strategic electricity power planning and a 10 years planning period was considered. Its usefulness was demonstrated by applying it for the analysis of the wind power integration in the electricity system. The second one, with a short-term horizon, aimed to solve the problem of the commissioning of power plants based on the available resources. The implementation of this model showed that modelling the electricity power systems requires a large set of constraints and a large number of data and information, resulting in significant computational effort to obtain a optimal solution. The development of a third model, a simplified approach of the short-term model, became therefore necessary. As previously, both short-term model and its simplified approach were used for the analysis of the impacts of wind power in the electricity system and in the operation of the different power plants. The last model resulted from the combination of the strategic electricity power planning model with the simplified model proposed for the commissioning of the power plants. The goal of this fourth model is to allow the inclusion of RES impacts in the design of scenarios for the electricity system, for a 10 years planning period.

The models application demonstrated the need to acknowledge and include the impacts of RES integration, particularly wind power, on the strategic electricity expansion planning. Throughout the work, the complexity of models was evidenced along with the difficulties that non-experienced users may face when applying them. A user-friendly platform enabling researchers and stakeholders to deal with electricity planning problems in a simpler but reliable way was then proposed, resulting in an important contribution for the effective dissemination and usage of these models.

Keywords: Renewable energy sources (RES); Electricity planning; Energy decision making; Optimization models; Wind power; Thermal power; Hydropower.

Resumo

A tomada de decisão no sector da energia, e em particular no sector da eletricidade, é uma atividade complexa, sendo frequentemente suportada em modelos de otimização, para apoio à resolução de problemas relativos ao planeamento elétrico. O crescimento da utilização das fontes de energia renováveis para a produção de eletricidade tem sido consistente nos últimos anos, sendo este crescimento justificado pelas preocupações relativas à segurança do abastecimento, passando por estratégias de diversificação de tecnologias e fornecedores, pela necessidade de redução da dependência energética externa de diversos paises Europeus, onde se inclui o caso português, e pelos objetivos de redução dos gases com efeito de estufa. Apesar dos seus benefícios, a integração das energias renováveis está frequentemente associada à dificuldade de previsão da produção de eletricidade e à produção variável, trazendo assim desafios consideráveis à gestão do sistema elétrico e ao seu planeamento.

Este trabalho centra-se na avaliação dos impactos das energias renováveis nos sistemas elétricos e na sua inclusão no planeamento elétrico de curto e longo prazo. Tem assim como objetivos principais analisar de que modo o crescimento das energias renováveis poderá afetar o sistema elétrico e as diferentes unidades produtoras, bem como propor novos modelos de otimização para planeamento estratégico para o setor elétrico que permitam reconhecer e incluir estes impactos, dotando assim o decisor de ferramentas que o possam apoiar da definição de cenários estratégicos de longo prazo.

De acordo com os objetivos traçados, são apresentados quatro diferentes modelos de otimização. Todos estes modelos foram testados para um sistema elétrico com caracteristicas próximas do caso português, detacando-se as componentes hídrica, térmica e eólica. O primeiro modelo visa o planeamento estratégico a longo prazo resultando na apresentação e caracterização de cenários para o setor elétrico para um período de 10 anos, tendo sido demonstrada a sua aplicação para a análise da integração da energia eólica no sistema. O segundo modelo utiliza um horizonte temporal de curto prazo, tendo como objetivo apoiar a resolução do problema de comissionamento das unidades de geração eléctrica com base nos recursos disponíveis. A sua implementação demonstrou que a modelação dos sistemas de geração de energia eléctrica pressupõe um conjunto de restrições e um elevado número de dados e informações que resultam num esforço computacional significativo. Desta forma, surgiu a necessidade de desenvolver um terceiro modelo que consiste numa versão simplificada deste modelo de curto-prazo. Ambos os modelos de curto prazo, foram também utilizados para a análise dos impactos da energia eólica no funcionamento das diferentes unidades de produção de eletricidade. O último modelo desenvolvido resulta da combinação do modelo estratégico de expansão do sistema elétrico com o modelo aplicado ao problema do comissionamento das unidades de geração eléctrica, tendo como objetivo ter em consideração os impactos das energias renováveis na definição de cenários para o setor elétrico para um período de 10 anos.

Da aplicação dos modelos fica demonstrada a importância de reconhecer e incluir no planeamento elétrico estratégico de longo prazo os impactos resultantes da integração de fontes renováveis de energia de produção variável, e em particular da energia eólica, nos sistemas elétricos. Fica ainda evidente, a complexidade dos modelos e a dificuldade de aplicação por utilizadores menos experientes. Resulta por isso como uma importante contribuição, o desenvolvimento de uma aplicação gráfica com interface amigável que deverá permitir a ampla disseminação dos modelos desenvolvidos e sua adaptação a diferentes sistemas elétricos.

Palavras chave: Fontes de energia renováveis; Planeamento elétrico; Tomada de decisão no setor energético; Modelos de otimização; Energia eólica; Centrais termoelétricas; Centrais hidroelétricas.

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List of Abbreviations and Acronyms

a_c, b_c, c_c	Coefficients of coal quadratic curves
a_g, b_g, c_g	Coefficients of gas quadratic curves
a^f_{eCoal}, b^f_{eCoal}, c^f_{eCoal}	Existent quadratic curve coefficients of coal fuel costs
a^f_{eGas}, b^f_{eGas}, c^f_{eGas}	Existent quadratic curve coefficients of gas fuel costs
a^f_{nCoal}, b^f_{nCoal}, c^f_{nCoal}	New quadratic curve coefficients of coal fuel costs
a^f_{nGas}, b^f_{nGas}, c^f_{nGas}	New quadratic curve coefficients of gas fuel costs
a^e_{eCoal}, b^e_{eCoal}, c^e_{eCoal}	Existent quadratic curve coefficients of coal CO_2 emissions
a^e_{eGas}, b^e_{eGas}, c^e_{eGas}	Existent quadratic curve coefficients of gas CO_2 emissions
a^e_{nCoal}, b^e_{nCoal}, c^e_{nCoal}	New quadratic curve coefficients of coal CO_2 emissions
a^e_{nGas}, b^e_{nGas}, c^e_{nGas}	New quadratic curve coefficients of gas CO_2 emissions
α	Spinning reserve (Chapter 3)
$\alpha(tri, h)$	Wind availability for trimester tri, hour h of planning period
β	Relationship between pumping and wind installed power (chapter 2)
β	System spinning reserve (chapter 5)
Δ_m	Number of hours for month m
η_p	Efficiency of pumping power plants
η_{epump}	Efficiency of existent pumping plants
η_{npump}	Efficiency of new pumping plants

$\phi(tri, h)$	run–of–river plants availability in trimester tri and hour h of planning period
$\phi_{hr,t}$	Run–of–river availability in hour t
$\phi_{t,e}$	Wind availability in hour t
$\varphi_{i,m}$	Availability factor of power unit i in month m
C	Set of all coal power plants
$C_{t,j}$	Total cost of thermal power group j in hour t (€)
CCGT	Combined Cycle Gas Turbines
CCS	Carbon Capture and Storage
$ColdS_j$	Cost of the cold startup of power group j (€)
Cp_i	Cost of pumping for each i type of power plant (€/MWh)
$CFOM_n$	Fixed O&M cost of the n type of power plant (€/MW) (Chapter 2)
$CFOM_n$	Fixed O&M cost of new wind, hydropower with reservoir and run-of-river power plants (€/MW) (Chapter 5)
$CFOM_{nCoal}$	Fixed O&M cost of new coal power groups (€/MW)
$CFOM_{nGas}$	Fixed O&M cost of new gas power groups (€/MW)
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_{2_i}	CO_2 emission factor of each i power plant type (ton/MWh)
CO_{2_j}	CO_2 emission factor of each j thermal power group (ton/MWh)
Cp_p	Pumping cost (€/MWh)
CSd_j	Shutdown cost of thermal power group j (€)
$CVOM_e$	Variable O&M cost of wind power plant (€/MWh)
$CVOM_{hd}$	Variable O&M cost of hydropower plants with reservoir (€/MWh)
$CVOM_{hr}$	Variable O&M cost of run–of–river power plants(€/MWh)
$CVOM_i$	Variable O&M costs for each i type of power plant (€/MWh)
$CVOM_i(t, tri)$	Variable O&M cost of all power plants included in the system in year t for trimester tri (€)
$CVOM_j$	Variable O&M cost of thermal power group j (€/MWh)

$CVOM_p$	Variable O&M cost of pumping power plants (€/MWh)
D_t	Demand in hour t of planning period (MWh)
dp	Share of renewable SRP and renewable and non-renewable cogeneration plants
$D_{m,t}$	Demand in month m of year t (MWh)
$D(t, tri, h)$	Demand in year t, trimester tri, and hour h of the planning period (MWh)
DT_j	Minimum down time of thermal group j
$dump_{m,t}$	Pumping unusable energy in month m of the year t
e	e power plant belonging to the set of existent power plants
$E\_Hydropump$	Set of all existent large hydropower plants with pumping capacity
$E\_Hydroreserve$	Set of all existent hydropower plants with reservoir
$E\_Hydrorr$	Set of existent run-of-river hydropower plants
E_Wind	Set of existent wind power plants
EC	CO_2 emission allowance cost (€/ton)
$ECoal$	Set of existent coal power groups
$EGas$	Set of existent gas power groups
eHa	eHa hydropower plant with reservoir belonging to the set of all existent hydropower plants
eHr	eHr run-of-river plant belonging to the set of all existent run-of-river plants
$EHydro$	Set of all existent hydropower plants
EnergyPLAN	Advanced energy system analysis computer model
ESAM	Electricity Systems' Analysis Models
$ETher$	Set of all existent thermal power groups
ETSAP	Energy Technology Systems Analysis Programme
EU	European Union
$eWind$	$eWind$ wind power plant belonging to the set of all existent wind power plants
$EWind$	Set of all existent wind power plants

F_{egas}	fuel cost of existent gas power groups (€$/m^3$)
F_{ngas}	fuel cost of new gas power groups (€$/m^3$)
F_i	Fuel cost for each i type of power plant (€/MWh)
F_j	Fuel cost of group j (€/MWh)
G	Set of all gas power plants
GAMS	General Algebraic Modeling System
GEP	Generation Expansion Planning
GHG	Greenhouse Gas
h	Planning period in hours
HOMER	Hybrid Optimization of Multiple Energy Resources
$HotS_j$	Cost of the hot startup of power group j (€)
HP	Hydropower potential
HPI	Hydraulic productivity index
I	Set of all power plants (Chapter 2)
I	Set of all power plants/groups except pumping plants (Chapter 5)
Ic_n	Investment cost of the n new power plant (€/MW) (Chapter 2)
Ic_n	Investment cost of new wind, hydropower with reservoir and run-of-river power plants (€/MW) (Chapter 5)
Ic_{nCoal}	Investment cost of new coal power groups (€/MW)
Ic_{nGas}	Investment cost of new gas power groups (€/MW)
IEA	International Energy Agency
I_E	Set of all existent power plants
IIASA	International Institute for Applied Systems Analysis
I_N	Set of all new power plants
$Inflows_t$	Hydro inflow on hour t of the planning period
$Inflows_{m,t}$	Hydro inflow on month m of the year t (MWh)
$Inflows(t, tri)$	Hydro inflow in year t and trimester tri of the planning period (MWh)
IPCC	Panel of Climate Change

$Ip_{e,t}$	Installed power of unit e in year t (MW)
$Ip_{n,t}$	Installed power of n power plant in year t (MW)
Ip_n	Installed power of new wind, hydropower with reservoir and run-of-river power plants (MW)
Ip_{nCoal}	Installed power of new coal power groups (MW)
Ip_{nGas}	Installed power of new gas power groups (MW)
$Ipow$	Installed power of the existent coal and gas power groups
$IP_{srt}(t)$	Installed power of SRP in year t
Ir	Initial reserve in the reservoir
j	Annual discount rate
J	Set of all thermal power groups included in the system (Chapter 3 and 4)
$L_c(t)$	Load factor of coal power groups (MW)
$L_g(t)$	Load factor of gas power groups (MW)
$L_{eCoal}(t, tri, h, eCoal)$	Load factor of the $eCoal$ power group in year t, trimester tri, and hour h of the planning period
$L_{eGas}(t, tri, h, eGas)$	Load factor of the $eGas$ power group in year t, trimester tri, and hour h of the planning period
$L_{nCoal}(t, tri, h, nCoal)$	Load factor of the $nCoal$ power group in year t, trimester tri, and hour h of the planning period
$L_{nGas}(t, tri, h, nGas)$	Load factor of the $nGas$ power group in year t, trimester tri, and hour h of the planning period
LBHG	Lost of biggest hydropower plants
LBTG	Lost of biggest thermal power groups
LEAP	Long range Energy Alternatives Planning System
LH	Potential reduction of hydropower due to a dry regime
LP	Linear programming
LSRP	Potential loss of SRP due to an unfavorable regime
lt_n	Lifetime of n new power plant (years)

LW	Potential reduction of wind power due to the lack of wind
M	Set of months per year of planning
MARKAL	Market Allocation
$max\_pumping\_reserve$	Maximum level for the pumping reserve
$maxR$	Maximum reservoir level
$maxR_{m,t}$	Maximum reservoir level on month m of year t
$maxReservoir$	Maximum capacity of reservoir (MWh)
mc_n	modular capacity of each new n power group
$mc(nCoal)$	modular capacity of each new coal power group
$mc(nGas)$	modular capacity of each new gas power group
MESSAGE	Modeling framework for medium to long-term energy system planning, energy policy analysis, and scenario development
MILP	Mix Integer Linear Problem
$min\_pumping\_reserve$	Minimum level for the pumping reserve
$minR_{m,t}$	Minimum reservoir level allowed
MINLP	Mix Integer Non Linear Problem
MIP	Mix Integer Problem
N	Set of new wind, hydropower with reservoir and run-of-river power plants (Chapter 5)
N	Set of the new power plants to be included in the system (Chapter 2)
N_j	Time necessary for a cold startup in hours
$N\_Hydropump$	Set of all new large hydropower plants with pumping capacity
$N\_Hydroreserve$	Set of all new hydropower plants with reservoir
$N\_Hydrorr$	Set of new run-of-river hydropower plants
$N\_Offshore$	Set of wind offshore power plants
$N\_Onshore$	Set of wind onshore power plants
N_Wind	Set of the new wind power plants
$NCoal$	Set of new coal power groups

$new_{nCoal}(t, nCoal)$	Binary variable that is one if a new coal group is installed and zero if not in year t for trimester tri
$new_{nGas}(t, nGas)$	Binary variable that is one if a new gas group is installed and zero if not in year t for trimester
$NGas$	Set of new gas power groups
nHa	nHa hydropower plant with reservoir belonging to the set of all new hydropower plants
nHr	nHr run-of-river hydropower plant belonging to the set of all new hydropower plants
$NHydro$	Set of all new hydropower plants
NLQP	Nonlinear quadratic problem
$number\_units_{n,t}$	Number of new installed thermal groups in year t
$NTher$	Set of all new thermal power groups
$nWind$	$nWind$ wind power plant belonging to the set of all new wind power plants
$NWind$	Set of all new wind power plants
O&M	Operation and maintenance
ONV	Wind onshore potential
OFV	Wind offshore potential
ORP	Ordinary regime production
$\overline{P_e}$	Maximum capacity of wind power plants (MW)
$\overline{P_{h_d}}$	Maximum capacity of hydropower plants with reservoir (MW)
$\overline{P_{h_r}}$	Maximum capacity of run-of-river power plants with reservoir (MW)
$\overline{P_j}$	Maximum capacity of thermal power group j (MW)
$\underline{P_j}$	Minimum capacity of thermal power group j (MW)
$\overline{p_{j,t}}$	Maximum power generation of group j in hour t (MWh)
$\overline{P_p}$	Maximum capacity of pumping power plants (MW)
$P_{i,m,t}$	Power output from power plant i in month m of year t (MW)
$P(t, tri, h, i)$	Electricity power generated by the respective i power plant/group (MWh)

phd_t	Power output of hydropower plants with reservoir in hour t (MWh)
phr_t	Power output of run–of–river power plant in hour t (MWh)
PIr	Initial reserve in the pumping reservoir
$Pl(t)$	System peak load in year t
PLEXOS	Integrated Energy Model
$ppump_t$	Power output of pumping power plant in hour t (MWh)
$Preserve\_max$	Maximum capacity of pumping reservoir
$Preserve\_min$	Minimum capacity of pumping reservoir
$Preserve_t$	Reserve of the pumping storage hydropower plant in hour t
PRIMES	Energy System Model
$Psrp_t$	Generation output of all SRP (except wind power plants) including co-generation in each t hour of the planning period (MWh)
$Psrp(t, tri, h)$	Generation output of all SRP (except wind power plants) including co-generation in year t, trimester tri, and hour h of the planning period (MWh)
$PSRP_{m,t}$	Generation output of all SRP (except wind power plants) including co-generation in month m of year t (MW)
$Pump$	Set of all pumping power plants
$pumping\_reserve_{m,t}$	Reserve of the pumping storage hydropower plant in month m, of the year t
$pwind_t$	Power output of wind power plant in hour t (MWh)
$pt_{t,j}$	Power output of thermal power group j in hour t (MWh)
Rd_j	Ramp down limit of group j (MWh)
RES	Renewable Energy Sources
$reserve\_max$	Maximum hydro reservoir level (MWh)
$reserve\_min$	Minimum hydro reservoir level (MWh)
$reserve_t$	Reservoir level on hour t of the planning period (MWh)
$reserve_{m,t}$	Reservoir level on month m of the year t (MWh)
$reserve(t, tri)$	Reservoir level in year t and trimester tri of the planning period (MWh)
RM	Reserve margin

Ru_j	Ramp up limit of power group j (MWh)
S	Set of all power plants except pumping power plants
$Sd_{t,j}$	Shutdown cost of thermal power group j in hour t (€)
Sdr_j	Shutdown ramp limit of group j (MWh)
$share_r$	Goal for renewable energies
$share_{rr}$	Minimum share for new run-of-river power plants on the hydropower system
SRP	Special Regime Production
$Su_{t,j}$	Startup cost of thermal power group j in hour t (€)
Sur_j	Startup ramp limit of group j (MWh)
t	Planning period in years
t	Planning period in hours (Chapter 3 and 4)
T_E	Set of all existent thermal power plants
$TE_c(t, tri)$	Emission cost of each thermal power group in the year t for trimester tri (€)
$TF_c(t, tri)$	Fuel cost of each thermal power group in the year t for trimester tri (€)
TIMES	Integrated MARKAL-EFOM System
T_N	Set of all new thermal power plants
tri	Set of trimesters in year t
UC	Unit Commitment
UT_j	Minimum up time of thermal group j
$v_{t,j}$	Binary variable that is 1 if thermal power group j is on in hour t or 0 if it is off
WILMAR	Wind Power Integration in Liberalised Electricity Markets
WEC	World Energy Council

Chapter 1

Introduction and Thesis Overview

1.1 Motivation

High investments and costs are involved when dealing with the strategic expansion of the electricity system and with problems like unit commitment and economic dispatch. These investments are mainly associated with the construction of new power plants, and their operation and maintenance, as well as the operation and maintenance of existent ones. The investment in new power technologies supported on renewable energy resources (RES) is evident in a society that is increasingly more concerned with the environment. The paradigm of power planning where only economic interests were taking into account is now overcome. According to Ferreira (2008), decisions in the energy sector have a key role for a sustainable development, causing a high economic impact, environmental and social welfare of future generations.

The combination of energy efficiency with RES is a key strategy for a sustainable future, emphasized by European and Portuguese guiding policies. In fact, Portugal is a good example with respect to the integration of RES in its electricity system, which contributes to a high diversification of the energy mix. Portugal does not have own fossil fuel resources and the geographical and climatic conditions allowed the country to strongly rely on the use of technologies supported on RES for electricity production. To fulfil the RES objectives the construction of new power plants and the power reinforcing of existing ones is foreseen. Such is the case of hydropower that according to REN (2013) is expected to increase its installed power by 83% until 2023. The wind power stands also as an essential element in achieving the RES targets set for the European Union members. In Portugal, both wind and hydropower have a significant impact for the management of the operations of the electricity system and it is recognized that RES increase can encourage the reallocation of capacity and output among different generation options, setting a new equilibrium under new operating conditions.

Optimization models applied to design and management of electricity systems can bring considerable advantages to the central decision maker or to the investor, allowing them to recognize the cost and benefits of technologies in an integrated planning process, rather than by simple comparing projects and technologies. Traditionally, these models were build under a cost optimization approach. However, social and environmental concerns have been gaining increasing attention in the last years either translated as objectives or constraints of these models.

To solve optimization problems for strategic electricity expansion planning, average operating conditions of the power plants are frequently used. However, for electricity systems with high share of RES of variable output the use of these average values can be misleading, representing a significant oversimplification of the reality. To properly deal with the impact of RES of variable output, traditional optimization models must be able to integrate the short-term operational planning and dispatching process with the long range planning models. This new approach creates additional complexity and must be supported by the development of robust optimization procedures capable of dealing not only with non linear mixed integer models fully characterizing real scale electricity systems, but also able to combine optimal decisions in different time frames.

From the aforementioned, it can be concluded that RES integration can bring considerable challenges to the operation and management of an electricity system. The main motivation of this thesis is precisely to address these challenges under a strategic decision making perspective, contributing then to:

1. evaluate the impacts of RES in the electricity system;
2. recognize and integrate these impacts on the strategic electricity planning;
3. develop and apply electricity planning models and a graphical user-friendly tool, so these models can be used by practitioners and researchers;
4. analyze the particular case of Portugal designing and fully characterizing possible future electricity scenarios.

Since the integration of the short-term operational planning and dispatching process with the long range planning models is far from being fully explored in literature, the relevance and the innovative aspects of this study will be strongly related to the model development better combining both short and long-term models, showing its potential use for supporting strategic electricity planning of the Portuguese electricity system.

1.2 Objectives

This PhD project expects to contribute to support strategic decision making in electricity systems with high RES share. For this purpose, the development of optimization models for electricity power planning, considering short and long-term time horizons is envisaged. A combined strategic model will be proposed avoiding the use of average operating conditions to describe the power plant performance, and integrating short and long-term planning. The objectives to be accomplished follows.

- To develop new optimization models for electricity planning, based on an approach that integrates multi-periodic optimization models for generation expansion planning with optimization models for power plants allocation, based on available resources. The following models will be formulated: (1) a model for unit commitment (UC) of the electricity systems, also refereed as short-term model, (2) a model for long-term strategic planning of the electricity system, (3) an integrated model that combines both models.

- To translate the models into computational language for solving the optimization problems by considering state-of-the art solvers.

- To apply the proposed models to the electricity planning in Portugal, resulting in fully characterized scenarios, including cost, CO_2 emissions, external energy dependence, RES share and installed power per technology. Through a scenario analysis, the impact of the increasing levels of RES power plants on the operating conditions of the remaining power plants will be assessed, seeking to establish optimal plans for the future.

- To develop a userfriendly graphical interface that should contribute to the models dissemination and usage by practitioners and scientific community.

1.3 Methodology

According to Saunders et al. (2009) the "*research design will be the general plan of how you will go about answering your research question*". Thus, in order to conduct this research process, it is necessary to identify approaches, strategies, techniques, and procedures.

The use of optimization models to support the decision making in the electricity sector is a subject that has been well addressed in literature. One mistake in choosing which technology or which power plants to use in a specific instant may result in a lost of many million of euros. Furthermore, increasing importance of RES turns more difficult the task of the decision maker due to the impacts that these technologies, characterized by their variable output, have in the operating conditions of traditional thermal power plants.

Therefore, the focus of this work is concerned in answering the following questions:

- "Which are the impacts that RES of variable output, specially wind power, have on the electricity system?"
- "Till what extent can the integration of RES of variable output influence long-term strategic planning of the electricity system?"

The approach followed in this research process is the deductive approach. This approach "*involves the development of a theory that is subjected to a rigorous test*" (Saunders et al., 2009). According to Robson (2002), there is five steps in the deductive process namely:

1. Deducing a hypothesis;
2. Express the hypothesis in operational terms;
3. Test the operational hypothesis;
4. Examining the specific outcome;
5. If necessary, modify the theory in the light of the findings.

In what concern to the nature of this research, an explanatory study is considered. This research nature is intended to study a situation or problem, so that we will be able to illustrate the relationship between variables (Saunders et al., 2009).

This research process is an iterative process that follows the schematic presented on Figure 1.1. The methodology started with a comprehensive literature review whose goal was to understand all the issues related with the electricity planning problems and the state-of-the-art concerning the existent models, planning tools and power technology characterization.

Secondly, power planning models were developed and described by using optimization procedures, followed by its translation in computational modeling language (GAMS, 2011). Three main models were proposed and tested: a model for UC of the electricity systems, a model for long-term strategic planning of the electricity system, and an integrated model that combines both previous models. The models application required the previous characterization of the Portuguese electricity system in order to obtain data to be used as input parameters or constraints.

From the models application a set of electricity scenarios were designed and fully characterized, aiming to contribute for the evaluation of the impact of RES in the Portuguese electricity system. The obtained scenarios were also used for the comparison of the developed models allowing to draw conclusion on their usefulness for electricity planning.

A userfriendly graphical interface for the electricity systems analysis was also proposed, aiming the models dissemination and usage among non experienced users.

1.4 Thesis synopsis

This thesis is composed by 7 main chapters briefly described in the following paragraphs. Aside the first and last chapter, that consists of introduction and conclusion, chapter 2 to 6 consists in a compilation of works/studies that sought to accomplish with the research objectives previously described. Each one of these five works/studies were developed as papers and were presented herein in their final format. The status, published/submitted, of each one is presented in the beginning of corresponding chapter.

Chapter 1 presents a short introduction and motivation of this work. Furthermore, both objectives and also the methodology followed to accomplish with these objectives are stated in this chapter. Also, a deeper and overall overview over the tools to support energy decision making and their importance is conducted. A more specific analysis over the problems of strategic generation expansion planning and short-term management operation of the electricity system (UC), is presented in more detail. From the literature review, an analysis over the possible impacts of RES in the electricity system is presented. Finally the characterization of the Portuguese electricity system is also addressed

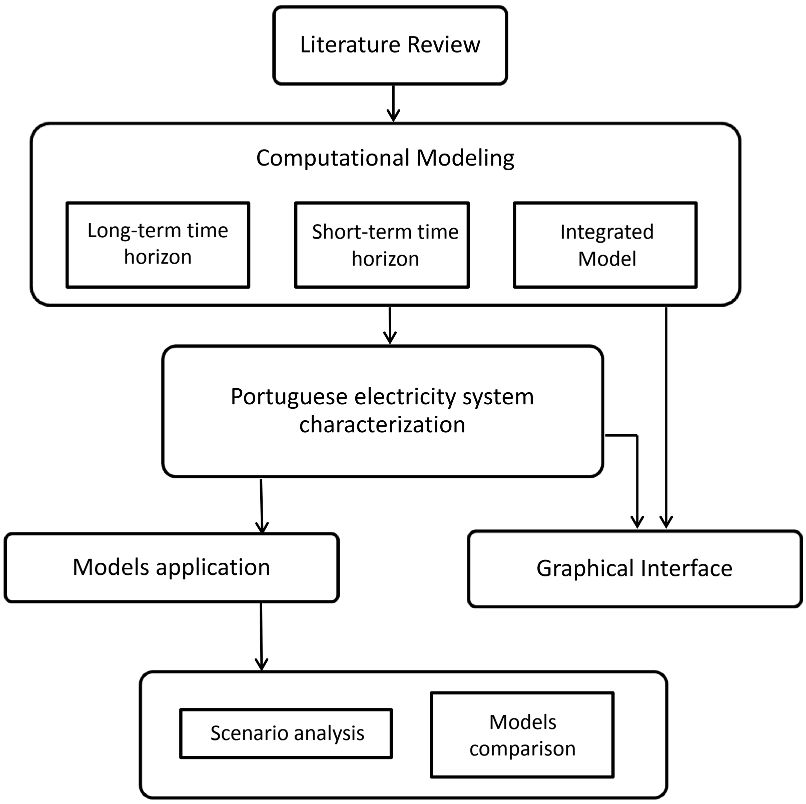

Figure 1.1: Schematic of the process used in the research project

over this chapter.

Chapter 2 refers to the paper named "Optimization modelling to support renewables integration in power systems". This work contribution is related to the development of an optimization model for the strategic expansion planning problem. A mixed integer linear problem (MILP) is presented and applied to a hydro-thermal-wind power system close to the Portuguese one. This study analyses in particular the impacts, in terms of costs, energy dependency and emissions released, of large integration of wind power in the electricity system. The study demonstrates also the importance of considering other solutions that despite not being Pareto cost optimal may present other considerable advantages to the electricity system under the decision makers perspective.

Chapter 3 corresponds to the second paper, entitled "Short-term electricity planning with increase wind capacity". The contribution of this study is concerned to the development of a new optimization model for the short-term management operation of the electricity system. This problem, also known as UC problem, is a binary mixed integer non-linear optimization problem (MINLP) with hourly time step. Applied to a system close to the Portuguese one, this work assumes demand forecasts for the year 2020 with increasing levels of installed wind power. The model allows to analyze the impact that this incresing amount of installed wind power will have in the operation of electricity system, specifically in the operation of thermal power plants. For this, the technical restrictions of thermal power plants operation, the hourly and intra-annual variation of the renewable resources and of the demand are included as parameters and restrictions of the model.

Recognizing the computational complexity of the model proposed in chapter 3, chapter 4 presents the paper named "A simplified optimization model to short-term electricity planning". This chapter contributes with a new model for the short-term management operations of the electricity system. The large number of variables and restrictions, necessary for a good and more accurate representation of any electricity system, require high computational resources, frequently resulting in high computation times. This new model represents then a simplified approach of the model presented in chapter 3. A non-linear optimization problem instead of a MINLP is therefore presented, contributing to a significant reduction of the required computational time. This allows to consider and analyse a large variety of scenarios with the possibility of proceeding further with in-depth analysis of only a few of these scenarios, resorting to the model presented in chapter 3.

Chapter 5 is refereed to the paper entitled "Generation expansion planning with high share of renewables of variable output." The contribution of this paper is related to the development of a model that combines the generation expansion planning problem with the optimization model for short-term operation of power plants, based on the available resources. Combining both models, the typical hourly data associated to the power plants allocation, can be used on the analysis of generation expansion planning, avoiding by this way the assumption of average operating conditions. The model application results then on the proposal of a set of long-term scenarios, whose design and characterization relies on more realistic assumptions recognizing the technical restrictions of thermal power plants, and the implications of high RES shares. The model application was demonstrated to a system close to the Portuguese one and a comparative analysis between this model and the one presented in chapter 2 was performed. The results allows to validate the usefulness of the integrated model.

Chapter 6 represents the last developed study translated in the paper entitled, “A userfriendly tool for electricity systems analysis”. This paper describes the development of a new userfriendly graphical tool (coined as ESAM) to support electricity decision making. This tool aggregates all four models presented and described in chapters 2 to 5 and intends to simplify the way that users can use all models previously described. With a graphical interface, this tool aims to be userfriendly, avoiding the user need to deal or have in-depth knowledge of programming or mathematics. Developed in Microsoft Visual Studio, ESAM tool is also a freeware tool.

Finally, Chapter 7 summarizes the performed work, presenting the main conclusions and suggesting possible outlines for future work.

1.5 State of the art

Optimization models have been applied in a several different sectors over the time. Energy sector, and in particular electricity generation sector, is not different. According to Foley et al. (2010), electricity systems models are tools used by electricity analysts such as engineers, economists and planners to manage and plan the electricity system, to trade electricity and for generation expansion planning purposes. Depending of the intended goal, different technics and concerns can be taken into account, leading to different and complex problems. Along with this, the diversity of factors affecting electricity generation makes with that becomes essential the use of mathematical models to support energy decision making. Therefore, next subsections will present an overview over the existent models presented in literature with special focus on the problems considered during the present work.

1.5.1 Energy planning models

The diversity of tools, models, within the reach of the decision makers is increasing over the time. Their technics and consequently their applications vary according to the set of different constraints and considerations. One of these optimization models considerations, when applied to electricity generation, is its classification according to their time horizon and their objectives. According to Hobbs (1995), depending of the problem that is intended to analyze, different horizon times can usually be considered. Typically applied to Generation expansion planning (GEP) problems, long-term horizon time comprises a time horizon that ranges from 10 to 40 years. These problems are quite associated with the strategic decision making, considering long–range forecasts and their main goal is to proposed optimal power generation mixes that can meet the forecasted demand. For the UC and the economic dispatch problem, the horizon time ranges from 8 hours to one week, and the objective is to obtain a solution that minimizes operating costs given the load, the technical characteristics of the available generators and the legal requirements applied to operators.

The difficulty addressed to find a specific tool that aggregates all issues related to energy decision making integration is evident. In fact, there are no tool capable to consider all issues related for example with renewable energy integration, instead, the "ideal" tool is highly dependent of the objective that is intended to achieve (Connolly et al., 2010). Connolly et al. (2010) presented in their study a survey review over 37 different energy tools where the perception of the no existence of "ideal" tool is enhanced by the consideration and analysis of different energy-sectors and technologies, time parameters, tools availability and previous studies.

Depending on the problem to be analysed and on its objectives, there are tools that are more suitable than others to be used in a given specific problem. For example, MARKAL (ETSAP, 1976) is a mathematical model of the energy system that "*computes energy balances at all levels of an energy system: primary resources, secondary fuels, final energy, and energy services*" (IEA, 2009). It was developed in a cooperative multinational project by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA) that starts in 1978 and the main objective is to obtain energy services at minimum global costs. MARKAL has been applied in several works over the time concerning energy investments (Wright et al., 2010; Cosmi et al., 2003), climate change control focusing on the emissions reduction (Zwaan and Smekens, 2009; Kannan and Strachan, 2009; Chen, 2011), and transportation (Gul et al., 2009).

In Wright et al. (2010) study, the authors enhanced the necessity of extensive new generating capacity investment in Cuban power sector. New capacity builds, investment spending requirements, electricity prices, fuel expenditures, and carbon dioxide emissions for different scenario were assessed considering least-cost investment strategies. In Cosmi et al. (2003) the authors evidenced the huge capital investment and major infrastructure changes required to verify the effectiveness of renewable technologies. An application resorting to MARKAL model is used to investigate the feasibility of renewables on electricity and thermal energy production taking into account legal issues and physical limits of the system in Southern Italy.

Zwaan and Smekens (2009) focused their study on the efficiency of carbon capture and storage (CCS). A detailed sensitivity analysis for a case study in Europe was performed using MARKAL model and considering a large set of CCS technologies and storage options. Also Chen (2011) adressed possible strategies to climate change control. Using MARKAL model, and under the support of China-UK Near Zero Emissions Coal initiative the author studied the perspective of the energy technologies that may be deployed in China until 2050. The author also examined the cost and impact of integrate CCS technology. In Kannan and Strachan (2009) study, a scenario and modeling assessment of new targets for CO_2 reduction was presented for the UK residential sector, resorting to MARKAL tool.

Gul et al. (2009), dealt with the long-term prospects of alternative fuels in global personal transport. The authors goal was to access key drivers and key bottlenecks of alternative fuels integration with focus on biofuels and hydrogen to meet climate policy objectives, once more using MARKAL for the analysis.

More recently, TIMES (integrated MARKAL-EFOM System) (ETSAP, 1976) model generator was developed. It uses long-term energy scenarios to conduct in-depth energy and environmental analysis. Combining two different, but complementary, systematic approaches to modeling energy, a technical engineering approach and an economic approach, TIMES is a bottom-up model generator, which uses linear-programming to produce a least-cost energy system over medium to long-term time horizons (IEA, 2009). TIMES code is written in GAMS (GAMS, 2011). Moreover and according to Deane et al. (2012); Kannan and Turton (2013), despite usually applied to the analysis of the entire energy sector, TIMES model may also be applied to study in detail single sectors, as is for example the case of electricity sector. Example of that are the numerous different works presented in literature. For example, Comodi et al. (2012) and Cosmi et al. (2009), though in different scale, focused their study in the Italian system. In Comodi et al. (2012), a case study for a seaside municipality was addressed. Different scenarios were considered and TIMES model was used to assess the effectiveness of local-scale energy policies in households, transport, and, public sectors. Estimated costs of implementing a number of energy policies were obtained as result. In Cosmi et al. (2009) a new model for the Italian energy system was presented and its structure reviewed sector by sector. The obtained results were shown in terms of the primary energy, finally energy consumption, transportation and CO_2 emissions.

Environmental concerns are not new nowadays and TIMES model has been also applied in several works concerning this issue. Example of that are the works of McCollum et al. (2012) and Føyn et al. (2011). In McCollum et al. (2012) the authors focused their work in the regulation of greenhouse gas (GHG) emissions, addressing the potential evolution of the transportation, fuel supply, and electric generation sectors, with the results showing that mitigation strategies include the management of the growth in energy service demand, the increase investments in efficiency and low-carbon energy supply technologies, and the promotion of demand technologies. In Føyn et al. (2011) the possibility of a 100% renewable energy system using data of the existing ETSAP2-TIAM global energy system model was tested, analysing the global and regional energy consumption of the system and the emission of GHG and thereby, the potential increase in global mean temperature.

Several other works where TIMES model was applied, as is the case of Jia et al. (2011), Kannan and Turton (2013), and Forsell et al. (2013) can be seen over the literature. Despite the possibility to analyse the energy sector as a whole, a significant part of these works address one or more specific energy sector. For example in Kannan and Turton (2013) a long-term electricity dispatch model was presented. Following the same idea, in Forsell et al. (2013), a model to study the future of biomass in Sweden and France was presented. Using TIMES model, the authors evaluated the generation potential derived from domestic biomass sources over the forestry supply.

Developed and maintained by the Sustainable Energy Planning Research Group at Aalborg University since 1999, the EnergyPLAN (1999) model, is used to study the operation of national systems on an hourly basis. EnergyPLAN operation analysis includes electricity, heating, cooling, industry, and transport sectors. Programmed in Delphi Pascal, the model has a user-friendly interface and is freeware (EnergyPLAN, 1999; Connolly et al., 2010). EnergyPLAN is also used to modeling all thermal, renewable storage/conversion, transports and costs. According to Connolly et al. (2010, pg. 1068), EnergyPLAN "*optimises the operation of a given system as opposed to tools which optimise the investment in the system*". Another particularity of EnergyPLAN model is that it is capable to analyse sudden changes in energy systems and, in particular, in systems with high intermittency due to RES integration (Mathiesen et al., 2011). A large number of works have being resorting to EnergyPLAN to analyse 100% RES systems. In Mathiesen et al. (2011), the analysis and design of a 100% renewable system for Denmark, including transport, by 2050 was presented. Results showed that energy savings, renewable energy integration and more efficient conversion technologies can lead to the technical possibility of the implementation of a 100% renewable energy system with positive socio-economic effects. In Connolly et al. (2011), the authors addressed the high dependency of Ireland on fossil fuels and analysed the possible achievement of a 100% RES system. In Ćosić et al. (2012), EnergyPLAN model was applied to Macedonia energy-system and two scenarios, one for 50% renewable energy system by 2030 and other for 100% renewable system by 2050, were considered. Results showed that first scenario is much more realistic due to the system characterization, however, with energy efficiency measures, 100% renewable energy system can be achieved. In Sáfián (2014), EnergyPLAN model was applied to Hungarian energy-system. Two alternative models were created and validated using Hungarian and international statistics. Models were tested and executed with the perspective to obtain optimal results from environmental point of view. Finally, EnergyPLAN was also applied for the analysis of RES scenarios for the Portuguese electricity system, including the case of a 100% RES scenario (Fernandes and Ferreira, 2014).

Despite the large application in 100% RES studies, EnergyPLAN model is also widely used in a large variety of other studies with different objectives. For example Franco and Salza (2011), focused their study on the electrical sector in Italy, more properly in the impact of RES penetration. A set of different scenarios were developed, considering in each one the maximum RES penetration feasible. Results showed that an integrated development of combined heat and power (CHP) and electric mobility would help in the integration of wind and photovoltaic energy power in the system. In Mathiesen et al. (2008), the authors proposed the possibility of integrating transport into energy planning. In Krajačić et al. (2011), the negative impacts of the hydrocarbons in the environment were enhanced addressing in particular the importance of energy storage. Other studies as is the case of Øtergaard et al. (2010) and Liu et al. (2013) focused on the importance of renewable on the energy system as a CO_2 mitigation measure and fossil fuels independency strategy. In the first study, the self-sustainability of Aalborg Municipality's energy needs was proven to be achievable, resorting to the use of the local available sources in combination with significant energy saving measures, reductions in industrial fuel use and savings and fuel-substitutions in the transport sector. In Liu et al. (2013) study, the impact of wind penetration in the system was analysed for China with focus on the ability of electrical vehicles balancing the electricity demand and supply.

The importance of RES on energy planning and decision making is also well demonstrated with several models and tools addressing these RES systems and technologies. This the case of WILMAR Planning tool (WILMAR, 2006). Developed by an international consortium in the EU funded WILMAR project, WILMAR Planning tool is used to analyse optimal operation power systems assuming wind power production and load as stochastic parameters and supported on GAMS language. Works such as Troy et al. (2010), Keane et al. (2011), Tuohy et al. (2008), Meibom et al. (2011) focused on the impacts of increasing levels of wind power on the operation of base load power plants. Also Keane et al. (2011) and Meibom et al. (2011) addressed in their study the impacts of wind and load uncertainty on the operation of the power system. In the first case, a simulation for the Irish power system over one year in both a stochastic and deterministic mode was considered. In the second one a stochastic mixed integer linear optimization scheduling model with the objective of costs minimization was presented. In Tuohy et al. (2008), the impact of wind power in the Irish electricity system was analysed over different time frames, from seconds to daily planning. The authors conclude that the most important aspects to be considered for the electricity system management are the wind turbine technological characteristics, the provision of reserve to accommodate wind forecasting error and the method used to plan plants schedules. Other studies using WILMAR Planning tool can be seen for example in Nyamdash and Denny (2013), Sørensen et al. (2008), and Akmal et al. (2009).

Another tool usually presented in numerous works over the literature is the Long range Energy Alternatives Planning System (LEAP) model. LEAP (Heaps, 2012) is a software tool for energy policy analysis and climate change mitigation assessment developed at the Stockholm Environment Institute in 1980. It is an integrated modeling tool that can be used to track energy consumption, production and resource extraction in all sectors of an economy (Connolly et al., 2010; Heaps, 2012). LEAP model can be considered as a medium to long-term model and most of it analysis uses annual time step. According to Shabbir and Ahmad (2010), LEAP model has been successfully used in more than 150 countries worldwide for different purposes. In Shabbir and Ahmad (2010) LEAP model was used to propose the optimal transport policy that can lead to a reduction in the growth of fuel consumption and consequently, air pollution in Pakistan. Both Wang et al. (2010) and Huang et al. (2011) addressed in their study the need of energy demand forecasts for sustainable development planning. In the first case, results indicates that in order to achieve sustainable development, better technological progress, optimized industrial structure and improved energy efficiency is necessary. In the second case, LEAP model was applied to Taiwan energy system and scenarios compared assessing future energy demand and supply patterns and GHG emissions.

LEAP model has been used also in works such Jun et al. (2010) and Haydt et al. (2011). While in Jun et al. (2010) the aim of the work was to study the economic and environmental influence of RES on existing electricity generation market, in Haydt et al. (2011) different modeling methodologies (LEAP, TIMES, EnergyPLAN) for balancing the electricity supply sources and the electricity demand in systems with high penetration of intermittent renewable were analysed.

Along with the tools described above, several others can be found in literature with studies demonstrating their application and usefulness. Such is the case of PLEXOS (1999), PRIMES (1994), IKARUS (2009) or MESSAGE (IIASA, 1980) among others. PLEXOS is a power systems modeling tool used for electricity market modeling and planning worldwide (Deane et al., 2012). PLEXOS is a software that uses cutting-edge mathematical programming and stochastic optimization techniques and can be applied to a set of different problems such as production cost simulation, capacity expansion planning, renewable generation integration analysis, operational planning with stochastic optimization (PLEXOS, 1999). Usually PLEXOS resorts to linear or mixed integer linear programming. Some studies that use PLEXOS software include Curtis et al. (2013), (Deane et al., 2012), Higgins et al. (2014) , Tuohy et al. (2007) and Deane et al. (2014).

IKARUS is a dynamic bottom-up linear costs optimization scenario tool maintained by the institute of Energy Research at Jülich Research center (Connolly et al., 2010). According Connolly et al. (2010), IKARUS considers all sectors of the energy system, including a large set of generation, storage/conversion and transport technologies. IKARUS has been successful used for assessing the impacts of energy prices changes on energy system and emissions (Martinsen et al., 2007) , political decision processes (Martinsen and Krey, 2008), RES applied to the transportation sector (Martinsen et al., 2010) and energy systems analysis (Weber and Martinsen, 2013).

Started in 1993, PRIMES model was developed by National Technical University of Athens with the first objective of analysing and studying the market related mechanisms that can influence energy demand and supply and the context for technology penetration in the market (Capros; Connolly et al., 2010). Also used for energy policy markets analysis, PRIMES model was later used for market oriented modeling with the objective of following market liberalization. According Capros et al. (1999), PRIMES model can be used for simulation of the energy systems and their agents. Nowadays in its second version PRIMES model is a non-linear mixed complementarity model, translated in GAMS language.

Developed by International Institute for Applied Systems Analysis (IIASA), MESSAGE is a system engineering optimization tool used for planning medium to long-term energy systems. MESSAGE has been applied for the development of energy scenarios and identification of socioeconomic and technological strategies in response to the energy challenges analysis (Connolly et al., 2010; IIASA, 1980). Using 5 or 10 years time step with a maximum horizon time of 120 years, MESSAGE model can simulate a large set of thermal generation, renewables, storage/conversion, transport technology, CCS and costs (Connolly et al., 2010). Besides being used in several assessments and scenarios studies for major international entities such as Panel of Climate Change (IPCC), the World Energy Council (WEC), and the European Commission, MESSAGE model has been successful used in works such as Messner et al. (1996) and Keppo and Strubegger (2010) or more recently in Lucena et al. (2015).

1.5.2 Generation expansion planning

The problem of generation expansion planning (GEP) is extensively addressed over the literature. GEP problem aims to find the optimal strategy to plan the construction of new generation plants while satisfying technical and economical constraints (Careri et al., 2011). In line with this, Gitizadeh et al. (2013) details the GEP objectives as finding the technology type, number of generation power plants, size, and location of candidate plants within the planning horizon. On the other hand, Sirikum et al. (2007) refers to GEP has a large-scale mixed integer nonlinear programming (MINLP) problem and one of the most complex optimization problems. Also Karthikeyan et al. (2013) supports that GEP is one of the most important decision-making activities in electricity generation sector that intends to determine the minimum cost capacity addition plan that meets forecasted demand within a pre-specified planning horizon. In all the cases, the main objective of GEP problem is design electricity strategies that minimize the total investment, operating, and maintenance costs at the end of the planning horizon, subject to a large set of constraints. In fact, since earlier, the difficulty of decision makers to assess the best mix of power plants to generate electricity lead to constant improvements of technics to deal with this problem. Nowadays, associated to the nonlinearity, large scale, and to the discrete nature of the variables describing power plants size and allocation, these new improvements frequently aim to deal with the increasing penetration of RES into the grid, the increasing environmental concerns and the emergence of deregulated markets (Careri et al., 2011).

However, depending of the case study and where the problem is to be applied, the objective may change. This can be for example related to the liberalization of electricity markets. While in the traditional power systems the main objective is costs minimization, from the generation companies point of view, the main objective becomes maximization of profits. According Hemmati et al. (2013) and Pereira and Saraiva (2011), in the deregulated electricity market, each generation company tries to maximize its profit, satisfying the independent system operator criteria such as reliability, reserve margin and load growth.

For the GEP objectives, important differences exists on the techniques used to solve each problem. Techniques like linear programming (AlKhal et al., 2006), Bender's decomposition (Sirikum et al., 2007; Careri et al., 2011; Kazempour and Conejo, 2012), dynamic programming (Karaki et al., 2002; Jirutitijaroen and Singh, 2006), genetic algorithms (Pereira and Saraiva, 2010, 2011; Chung et al., 2004; Sirikum and Techanitisawad, 2006), mixed integer linear programming (MILP) (Zhou et al., 2011; Bakirtzis et al., 2012; Tekiner et al., 2010), multiple objective programming (Antunes et al., 2004; Tekiner-Mogulkoc et al., 2012; Aghaei et al., 2013a; Unsihuay-Vila et al., 2011; Gitizadeh et al., 2013), particle swarm optimization (Hassan et al., 2012; Kannan et al., 2004; Zhang et al., 2013; Moghddas-Tafreshi et al., 2011; Hemmati et al., 2013), stochastic/scenario based programming (Chang, 2014; Wogrin et al., 2011; Druenne et al., 2011; Feng and Ryan, 2013) and systems dynamics programming (Pereira and Saraiva, 2013) are widely used in the literature. For example in AlKhal et al. (2006), a mathematical linear programming model was formulated. The model was tested to evaluate the potential economic benefits for an integrated planning for several Middle East countries.

According to Kazempour and Conejo (2012), Benders' decomposition is an effective technic to use in high constrained problems and in problems that include a large number of variables. This technique resorts to the problem decomposition, which results in a problem that is easier to solve than the original one. In their study, the authors resorted to Benders' decomposition technic to solve a GEP problem for a specific target year. The author enhanced the good performance of the respective technic over diverse realistic case studies simulations. In Sirikum et al. (2007), a methodology called GA-based heuristic method was proposed and presented for the GEP. This technic was used to evaluate minimum investment costs in new thermal power plants taking into account restrictions on emissions, power capacity, loss of load probability, and location of the plants.

Other technic widely used in literature is the MINLP. In Bakirtzis et al. (2012) this technic was applied to a GEP problem with the objective of minimizing total investment, operating and unserved energy costs considering a specific planning horizon. Considering monthly time-step the authors performed a sensitivity analysis for Greek power system analysing the effect of demand, fuel prices and CO_2 prices uncertainties on the planning decisions. For the analysis, cost of purchasing emission allowances as well as inclusion of annual renewable quota constraints and penalties were taken into account in the model.

According to Antunes et al. (2004), as GEP involves multiple, conflicting and incommensurate objectives, instead of aggregating them in a single objective function, multiple objective functions can be used. This increase significantly the realism of these models. Furthermore, the use of multiple objective problems will allow to understand the trade-offs among the different objectives and to achieve compromise solutions. In Aghaei et al. (2013a) the authors have presented a Multi-period Multi-objective GEP model, considering three objectives, namely, costs, environmental, and reliability maximization. Pareto optimal solutions were therefore identified and used for the analysis of the tradeoff between objectives. In Zhang et al. (2013), a bi-level GEP problem considering large-scale wind generation was presented. The results were obtained by solving a multi-objective particle swarm algorithm. According the authors this technic allows to accelerate the convergence of optimal solution and guarantee the diversity of Pareto-optimal front.

Allied to the high complexity of GEP problems, the uncertainty of the respective parameters brings additional challenges. RES generation, load demand, market prices are some of the parameters addressed in GEP problems that due to its uncertainty increase significantly the complexity of the problems. To deal with this, stochastic/scenario based programming technics are used. For example in Chang (2014), a scenario based programming technic was applied to deal with the uncertainty of power supply system. A mixed integer programming (MIP) model was considered, aiming to identity the allocations of thermal, renewable, and nuclear power plants, along with the transmission network taking into account the uncertain factors of the power system. The authors applied their study to Taiwan power system, using CPLEX solver to achieve the results.

According to Pereira and Saraiva (2013, pg. 42),*"system dynamics is a modeling tool particularly suited to represent long-term problems that involve a large number of variables and parameters as well as loops and inter dependencies".* In this study the authors described a long-term GEP model able to evaluate the evolution of the demand and of the electricity price so generation companies agents can perform their expansion plans. The study was applied to the Portuguese/Spanish system aiming to identifying the most adequate expansion plans, considering increasing RES generation.

1.5.3 Short-term scheduling of generation power plants

Along with GEP problem, short-term scheduling of generation power plants is also frequently addressed in the electricity planning literature. Once more, this becomes evident due to the change of electricity paradigm where only economic concerns were taken into consideration and due to the emergence of deregulated markets. Also known as UC problem, short-term scheduling of generation power plants is defined as a decision making problem where the objective is to determine the hourly ON/OFF schedule and generation level (dispatch) of each generating power plant over a given time horizon, meeting the predicted load demand, plus the spinning reserve requirement at a specific time interval, and minimizing the total cost of production (Senjyu et al., 2003; Patra et al., 2009; Qin et al., 2010). With a time interval ranging between one day to one week (24-168h), besides the necessity of meet demand and spinning reserve, UC problem needs to have into account a set of generation constraints and also minimum up-time and down-time of power plants, which increase significantly the complexity of the problem (Kumar and Mohan, 2010; Dhanalakshmi et al., 2013).

UC plays an important role in the economic operation of the entire power system, either from the point of view of the generation companies or of the system manager. Thereby, a diversity of studies addressing this problem have been developed over the time, and several different technics have been applied to obtain the respective results. Optimization technics such as, Bender's decomposition (Zhao and Zeng, 2012; Bertsimas et al., 2013; Wang et al., 2013a), differential evolution (Mandal and Chakraborty, 2009; Lu et al., 2010; Qin et al., 2010), evolutionary algorithms (Jeong et al., 2009; Georgopoulou and Giannakoglou, 2009), genetic algorithms (Chiang, 2007; Kumar and Mohan, 2010; Dhanalakshmi et al., 2013), Lagrangian Relaxation (Frangioni et al., 2008, 2011), MILP optimization (Carrión and Arroyo, 2006; Wu, 2011; Xie et al., 2011; Viana and Pedroso, 2013), particle swarm optimization (Yuan et al., 2009; Wang and Singh, 2009; Park et al., 2010; Jeong et al., 2010), simulated annealing (Patra et al., 2009; Saraiva et al., 2011) and stochastic optimization (Siahkali and Vakilian, 2010; Ding et al., 2010; Wang et al., 2013b) are example of technics associated to UC problem described in the literature.

Bertsimas et al. (2013) shown in their work the difficult task of dealing with the UC problem due to the emergence of new challenges like supply and demand uncertainty, increase integration of technologies of variable output and market prices. In Mandal and Chakraborty (2009), both economic and environmental concerns were considered for the problem of short-term scheduling, resulting in a multi-objective problem. To solve the problem a algorithm based on differential evolution was used and a price penalty factor was considered, transforming the problem into a single objective one. The model was applied to a case study considering a cascade of four hydropower plants and three thermal power plants. Also Georgopoulou and Giannakoglou (2009) presented in their work a multi-objective short-term scheduling problem with stochastic demand data. However, in this particular case, a evolutionary algorithm method was considered. Along with costs minimization, the risk of not fulfilling possible demand variations was also to be minimized. With the objective of reduce the complexity of the problem, a two-level optimization algorithm was used and results were compared with previous results obtained with traditional evolutionary algorithms.

Proven to be successfully used in other problem, in Dhanalakshmi et al. (2013), a genetic algorithm was used to solve a generation scheduling problem. A specific method to deal with the minimum up/down time constraints was considered. Tests were conducted over one day time horizon with ten and twenty six power plants system. Results were compared with other well known technics.

Highly constrained, short-term scheduling problems are considered large-scale problems. Furthermore, most of the constraints associated to this problem are nonlinear which, along with the need to define the on/off status of a specific generation power plants, turns the scheduling problem in a hard to solve MINLP. One way to simplify this problem is through the use of piecewise linear approximations, transforming the MINLP into a MILP. This simplification is usual in literature. For example in Viana and Pedroso (2013), a quadratic programming formulation of a scheduling problem was proposed. To solve this problem, a simplification was conducted and a new optimization algorithm based on MILP was presented. For that, the authors resorted to a piecewise linear approximation of the quadratic fuel cost curve, which allowed to achieve quicker results. This new algorithm also allowed to tackle ramp constraints, neglected in some previous studies, with results demonstrating both the simplicity and effectiveness of this algorithm. According to Frangioni et al. (2008), other successful approach to solve scheduling problems is the use of lagrangian relaxation algorithm since constraints such as minimum up- and down-time and startup costs can be efficiently solved using dynamic programming techniques. However, in Frangioni et al. (2011), the authors called attention to the difficulties of previous algorithms to solve schedule problems considering ramp constraints. In their work, the authors proposed a method that combines lagrangian relaxation and MILP.

According to Saraiva et al. (2011, pg. 1283), simulated annealing "*is a very appealing metaheuristic easily implemented and providing good results in numerous optimization problems*". In their work, a case study for generator maintenance schedule, based on a generation system comprising twenty nine generation groups, was considered. The objective was to minimize the operational cost along the scheduling period and assuming penalty on energy not supplied. Other different technics were used by Yuan et al. (2009) and Siahkali and Vakilian (2010) to solve the proposed short-term schedule problem. While in the first case an improved binary particle swarm method was applied with the objective of comply with the spinning reserve requirements and minimum up/down time constraints, in the second case, a stochastic model was used to deal with the impacts that demand and wind uncertainty may inflict on the schedule of power system.

The inclusion of RES in UC problems has been addressed by several authors. Such is the case of works on hydro-thermal (Chiang, 2007; Mandal and Chakraborty, 2009; Qin et al., 2010) and wind-thermal (Chen, 2008; Khorsand et al., 2011; Azizipanah-Abarghooee et al., 2012; Aghaei et al., 2013b) generation. For example in Qin et al. (2010), a multi-objective optimization model, using differential evolution, was presented to solve the optimal hydro-thermal scheduling problem. On the same way, both economic and emissions objectives were considered in Chiang (2007) on an improved genetic algorithm for multi-objective short-term scheduling of a hydro-thermal system.

As for wind power integration, Azizipanah-Abarghooee et al. (2012) proposed a multiple objective economic emission dispatch problem aiming to minimize wind-thermal electrical energy cost and emissions. A stochastic search algorithm was used to handle system uncertainties. Khorsand et al. (2011), stressed the importance of considering the emissions objective even in high wind power scenarios, as wind power variability can lead to changes on thermal power generation scheduling which can influence the environment performance of the system. Therefore, a multi-objective mathematical programming model was proposed to solve the wind-thermal scheduling problem.

The issue of RES integration in the electricity systems and its impacts will be addressed in the following sub-chapter of this thesis, reviewing some of the studies on this topic.

1.6 RES integration in the power system

Electricity planning and decision making today are more complex than were in the past. The greater uncertainty in load growth, fuel markets, technological developments, government regulation and the increasing reliance on RES, are the main contributors of this increasing complexity. Environmental issues and global warming in particular are on the top of the society and most of government countries concerns, which have resulted in the agreement of Kyoto protocol (Gitizadeh et al., 2013). RES and in particular wind power, are seen as key technologies to achieve these agreement and therefore, to reach a sustainable power generation system (Goransson and Johnsson, 2009). Following this, and according to Albadi and El-Saadany (2010) there are three main reasons for the wind power increase. The first one is the society concerns with emissions, climate change and other environmental issues. The second is related with fossil fuel reserves depletion and the last one is the wind turbine technology improvement.

However, besides the environmental aspects, other positive aspects can be related to the integration of RES. These positive aspects include the contribution to the security of energy supply by promoting technological diversification and reducing energy imports, reduction on the operational costs of the power system by reducing fossil fuel consumption and avoiding the construction of new transmission lines and large generating plants, resulting in costs effective way to improve power quality and reliability (Lopes et al., 2007; Holttinen, 2008; Kaldellis and Zafirakis, 2011).

Despite all benefits, wind power growth introduces also some challenges to the power system operation. These challenges become more relevant as wind power share increases and depend on the flexibility level of the electricity system (Ackermann, 2005; Albadi and El-Saadany, 2010). According to Ackermann (2005), these impacts can be divided into short-term, related to balancing the system at the operation time scale, and long-term, related to the need to providing enough power during peak load moments. Thus, short-term impacts relate to voltage management, production efficiency of thermal or hydropower plants, transmission and distribution efficiency, reserve requirements and discarded energy. On the other hand, long-term impacts relate to the system reliability, with wind power contributing to system capacity increase but not necessarily contributing in the same amount to meet the peak demand.

Wind power impacts referred above are well identified in literature. Different study considering these impacts are addressed in a variety of ways including demand response (Jonghe et al., 2012), emissions (Denny and O'Malley, 2006; Delarue et al., 2009), transmission (Strbac et al., 2007), reserve requirements (Holttinen, 2005; Morales et al., 2009), UC (Ummels et al., 2007; Goransson and Johnsson, 2009; Tuohy et al., 2009) and voltage control (Lopes et al., 2007; Chen and Blaabjerg, 2009).

According to Jonghe et al. (2012), demand response is the ability of load to respond to short-term variations in electricity prices, especially during peak periods and fluctuations due to RES variability. In this work, a cost minimization model using linear programming and considering demand response was presented. The authors concluded that including demand response will smooth system peak load periods, reducing the need to invest in peak generation capacity. Demand response will also increase system flexibility, facilitating integration of variable wind power.

Wind power technology is known as having very low operational costs and priority access to the grid is frequently assumed on planning models, either due to its low costs or to RES support regulation. Besides that, wind power production and therefore its contribution to the mitigation of environmental concerns is recognized in different studies. In Delarue et al. (2009) a mixed integer linear programming tool that models wind power and its unpredictability was proposed to access the impacts of wind power in the system costs and emissions released. Zhu et al. (2014) presented an economic emission dispatch model to evaluate the importance of wind power on emissions mitigation and fossil fuel dependency. A bi-objective optimization problem was proposed minimizing both costs and emission released. In Brouwer et al. (2014), the impacts of RES in the electricity system were described. The authors concluded that with the increasing share of RES, thermal power plants will experience higher number of startups and shutdowns, ramp moments, and periods of time working at low efficiency leading to the increase of fuel consumption and CO_2 emissions released.

Another concern related to wind power integration has to due with the reserve requirements. Electricity generation must meet the demand at each time interval of the horizon time. However, along with the wind power, demand is also highly uncertain which turns difficult to determine the amount of reserve needed to face the variability of both wind power and demand. Thus, it is not too much to say that back up reserves are largely affected by load variations and by the dispersion of wind power (Albadi and El-Saadany, 2010). For example in Morales et al. (2009), a methodology to determine the required level of spinning and nonspinning reserves in a power system with a high penetration of wind power was proposed. Despite the expected operational costs decrease due to wind power output, the authors concluded that wind power uncertainty has a significant impact on the reserve cost, on the scheduled reserves and on generation/demand scheduling. In Wu et al. (2015), the authors proposed a model to evaluate the impacts of wind power, highly subjected to forecast errors, on the optimal reserve levels for the Chinese electricity system. Tests were conducted and the usefulness of the model evidenced. In Fernandez-Bernal et al. (2014) the authors evaluated the maximum share of wind power in system without affecting the reserve levels. A case study applied to the Spanish electricity system was presented with results showing the possibility of reaching a high share of wind power without consequences to the reserve levels.

Generation efficiency is highly dependent on wind variability as it affects the commitment of traditional power plants. This wind variability frequently originates increasing number of startups, ramping and periods of operation at low load levels, leading to suboptimal operating conditions of the conventional power plants. Therefore, in order to deal with this uncertainty, the use of accurate wind forecast technics is essential, reducing the risk associated to the wind uncertainty (Ackermann, 2005; Barth et al., 2006; Kiviluoma et al., 2011). For example in Tuohy et al. (2009), the impact of wind uncertainty in the unit commitment was assessed. Results showed that peak load technologies along with the interconnections are the most affected elements of the system. Furthermore, more up to date wind and load forecasts will result in the reduction of reserve needs.

Additionally, large wind power integration, usually achieved through large wind power plants located far from the load centers, can originate impacts on transmission, distribution and even on the wind turbine generator manufacture level can occur (Kabouris and Kanellos, 2010). As a matter of fact, according to Quezada et al. (2006) wind power can increase or decrease network losses depending on the wind penetration level, on the balancing between wind production and load profile and on the location of wind power generation. It is also evident that depending on the wind location generation and of the wind penetration level, congestions on the transmission can occur. Consequently investments in transmission may be necessary increasing the final electricity system costs (Albadi and El-Saadany, 2010). For example in Strbac et al. (2007) a study considering different levels of wind power generation was conducted for the UK electricity system. In this study, the authors considered the costs of wind generation, the costs of balancing the system, and the network connection and reinforcement costs. In what concerns to the possible benefits, fuel and conventional generation capacity and operation costs reduction were mentioned. An analysis between the costs and benefits of wind generation was than conducted. Results showed that an increase of wind power generation of 20% could result in an increase of electricity price around 5%, which the authors considered relatively small. Another conclusion is that, if significant wind power installed capacity is added to the system, significant cost increase is expected to occur in the system.

Lastly, another common and significative impact associated to the increase wind power penetration is the voltage variability. Voltage control in the transmission system is obtaining by controlling the reactive power. Since wind turbines affects the power flow of the grids (absorbing reactive power), and voltage are highly related with power flows, changes on voltage usually occurs. This voltage variability is also related with the wind power generation variability (Ackermann, 2005; Albadi and El-Saadany, 2010). Nowadays, new wind turbines started to emerge with technology capable to control the voltage and so, along with other known voltage control equipments, the mitigation of the voltage rise in the transmission is already ensured. A more detailed and technical approach the voltage rise effect can be seen in Lopes et al. (2007) and Chen and Blaabjerg (2009).

1.7 Portuguese electricity sector

Environmental problems have been highlighted over the recent years. This is evident in a world where societies are more and more concerned with their welfare. Even governments have been committed in both costs reduction and in fighting climate change, as was proven with the Kyoto protocol. This search for environmentally friendly solutions has been one of the key drivers for RES development all across the globe. In the past, the higher costs associated to the RES technologies were seen as an obstacle to its implementation, however, technology development allied with the energy policies supporting RES integration, gave rise to significant investments in the RES sector. Wind power generation has been presenting for long a highlighted role in the mitigation of the environmental problems. Indeed, world wind power installation has been increasing over the years. In the first half of 2014, wind grew 5.5%, more 0.5% than the same period of 2013. This corresponds to a total installed wind power of around 336 GW (WWEA, 2014). Figure 1.2 shows the world wind power evolution since 2012. Portugal is not different and the same pattern is noted in what concerns to wind power evolution. In fact, and according to ENEOP (2015), even occupying the 11° position in world wind power installed capacity, Portugal has the second higher level of wind power share, just behind Denmark.

The Portuguese electricity sector, presented in 2014 a total installed power equal to 17824 MW divided in two different regimes, the ordinary regime production (ORP) and the special regime production (SRP). While the ordinary regime includes the generation of the conventional thermal power plants plus the generation of large hydropower plants, SRP includes generation of all renewable power plants (excluding large hydro) plus cogeneration. The thermal power system is divided into coal and combined cycle gas turbines (CCGT) plants. In the end of 2014 coal power plants represented a total installed power of 1756 MW while CCGT plants have 3829 MW, resulting on a total capacity of

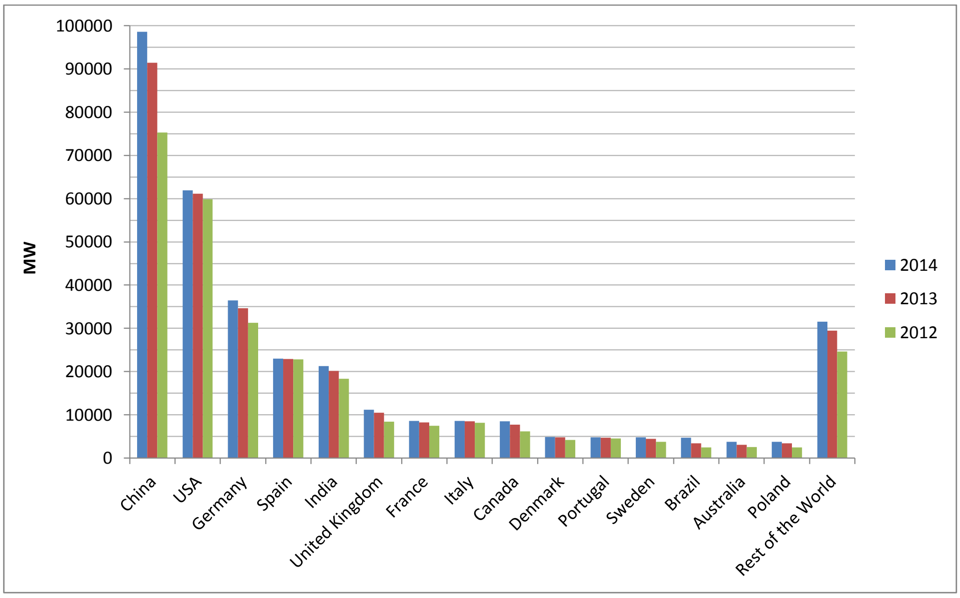

Figure 1.2: World wind power (Own elaboration (WWEA, 2014), February 2015)

5585 MW. On the other hand, large hydropower plants are divided into large hydropower plants with reservoir (dams) and run–of–river power plants. In the end of 2014 dams installed power reached 2681 MW while run-of-river plants reached 2588 MW, resulting on a 5269 MW of total installed large hydropower. In what concerns to the SRP, wind power is by far the dominant technology, with 4511 MW of installed capacity in 2014. This represented about 64% of total special regime installed capacity. The remain installed capacity is divided between biomass and cogeneration (1660 MW), small hydro (415 MW), and photovoltaic (383 MW) plants, resulting on a total installed power of 6969 MW (REN, 2014).

Figure 1.3 demonstrates the importance of wind power in the Portuguese electricity sector. Wind power is the technology with the higher installed power. Despite all challenges that this high wind power share may bring to the system, it also contributes to the increase diversity of the technologies mix and therefore, to the security of supply. In fact, the total electricity consumption in 2014 in Portugal was 48817 GWh (REN, 2014). ORP contributed with 27135 GWh, of which 14664 GWh from hydropower and 12471 GWh from thermal power plants. On the other hand, SRP regime have contributed with 21858 GWh, of which 11813 from wind power. This allows to verify the importance of renewable energies in the system, showing that just large hydro and wind power have contributed to 52% of all electricity generation. In Figure 1.4 is possible to analyse separately the contribution of different technologies to the

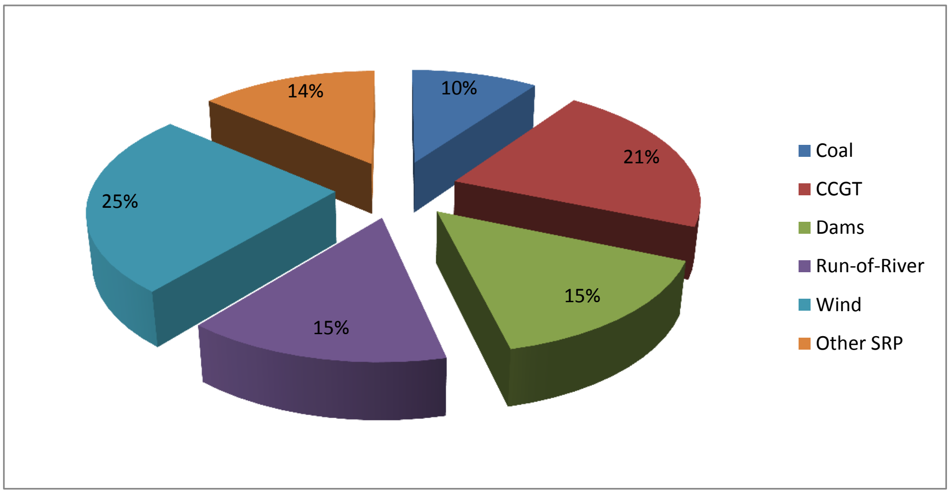

Figure 1.3: Installed capacity of Portuguese electricity sector (Own elaboration (REN, 2014), February 2015)

electricity generation.

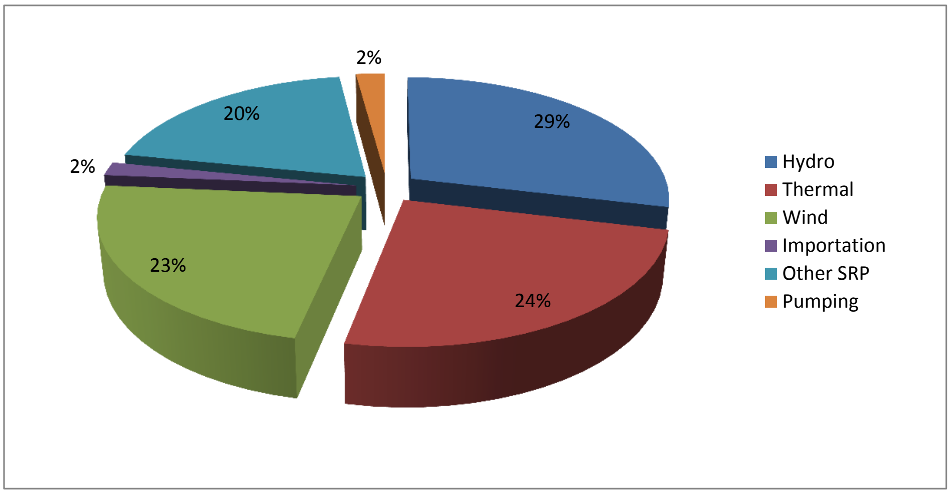

Figure 1.4: Electricity consumption in 2014 (Own elaboration (REN, 2014))

Despite not having the higher installed capacity when compared with the other countries (Figure 1.2), analysing both figures 1.3 and 1.4, is possible to confirm the relevant position of Portugal in what concerns to the wind share in the electricity system. This results from the Portuguese effort to reduce its high energy dependency, as the country is a major importer of fossil fuels, and to also achieve the environmental target assumed for GHG emissions. Directive

2009/28/EC for the promotion of the use of energy from renewable sources defined for Portugal a target of 31% share of energy from renewable sources in gross final consumption up to 2020. To achieve this target, investments in renewable technologies, mostly wind power were evident during the last years, as demonstrated in Figure 1.5.

However, higher shares of technologies of variable output, despite all benefits, create challenges to the system operator as demonstrated in previous sections of this chapter. The Portuguese electricity system, comprising a large set of RES and non-RES technologies, represents then an interesting case study worth to be considered for the evaluation of the impacts of RES integration and also for testing optimization tools for electricity planning.

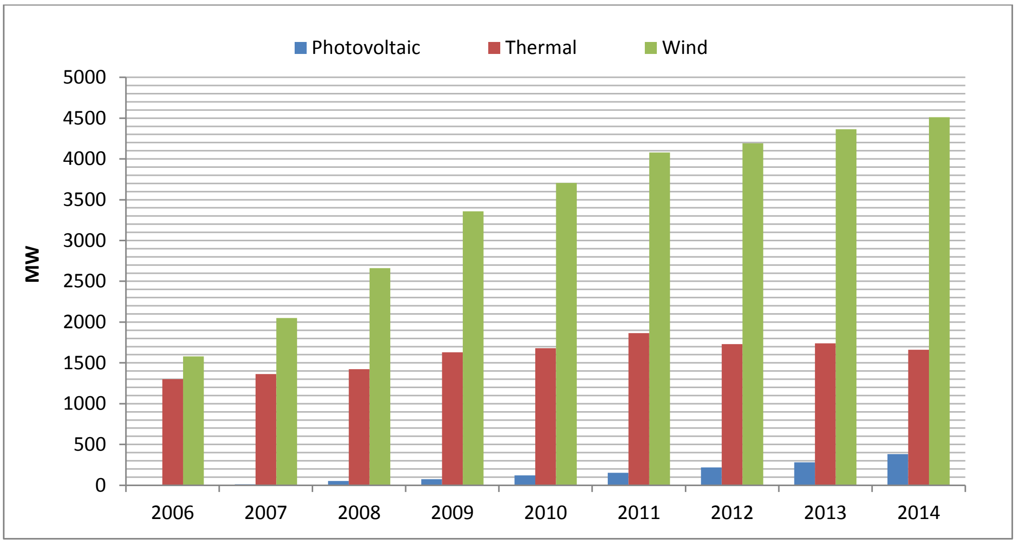

Figure 1.5: Evolution of RES for electricity production in Portugal (Own elaboration REN)

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Chapter 2

Optimization modelling to support renewables integration in power systems

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ABSTRACT

This paper focus on the problem of generation expansion planning and on the integration of increasing share of renewable energy sources (RES) technologies in the power grid. A survey of papers addressing the use of optimization models for electricity generation planning is presented. This literature review fed the design of an electricity power plan model able to integrate thermal and RES power plants. An analysis of different electricity scenarios for a mixed hydro-thermal-wind power system is presented resourcing to the proposed mixed integer optimization model. The results show the importance of these tools to support the strategic energy policy decision making under different regulatory or political scenarios. The expected impacts in terms of costs and CO_2 emissions are evaluated for a 10 years planning period, and a set of optimal scenarios is analyzed. The use of the model to obtain and characterize close to optimal scenarios is shown to be strategically useful. The particular case of the impact of different wind power scenarios is addressed, demonstrating the relevance of presenting other possible strategies that, although not being original Pareto solutions, may be worth to consider from the decision makers perspective.

Keywords: Energy decision making, Electricity planning, Electricity system analyzes.

2.1 Introduction

The decision making process for electricity power generation has been going through deep changes across time. Several aspects previously not considered as important, are nowadays getting an increasing attention from the decision makers. Therefore, tools that allow(s) to better support the increasingly difficult decision makers' task, play a fundamental role, particularly in addressing complex problems of electricity generation expansion planning. It is now commonly accepted that the underlying principles of the sustainable development concept must be recognized and included on power generation decisions, allowing to achieve satisfactory solutions from the cost, environmental, and social points of view. However, achieving these solutions is not an easy task, and the integrated resource planning should seek to identify the mix of resources that best meets the future energy needs of consumers, economy, environment, and society. Optimization models are proved to be helpful tools that can be used to provide better information, and thus, contributing to turn more accurate the decision maker policy. Several studies about energy planning models, where economic and environmental objectives are the predominant focus, are already available. A comprehensive review of energy modeling problems, addressing, among others, the energy planning models and the use of optimization tools, may be found in Jebaraj and Iniyan (2006) or Foley et al. (2010).

This paper contribution is threefold. Firstly, a revision on the long-term generation expansion planning is presented. The aim of this review is to provide an insight into the models used and their contribution to support energy decision making. Secondly, a contribution to the electricity planning field is aimed by presenting an useful tool for strategic energy decision makers specially designed to the particular case of mixed hydro-thermal-wind power systems. The proposed model allows to take into account the seasonality of the hydro and wind regimes. Run of river, hydro storage, and pumping units are included aiming to tackle the problem of wind power variability. The optimization model entails the formulation of economic and environmental objective functions, subject to a set of constrains translating the legal, technical and demand requirements of the system. Thirdly the model is used to present possible optimal electricity scenarios in the future for these systems, establishing investment and generation plans and evaluating the cost, emissions and external dependency impact. The results are enriched with an analysis of alternative power solutions, that are not located in the Pareto front but may be considered "close to optimal solutions". This last step is particularly useful to assist decision making regarding the future of wind power.

This paper is organized as follows. Section 2.2 provides some recent and representative examples from the literature, addressing the usage of optimization models for electricity power planning and the analysis of renewable energy sources (RES) integration in power planning modeling. Section 2.3 describes the proposed model formulation and in Section 2.4 a realistic case study is presented, and the results are analyzed. Finally, conclusions are stated in Section 2.5. The paper includes also an appendix detailing the obtained results.

2.2 Generation expansion planning

Until the 1970's the electricity planning problem consisted basically in determining the best size, timing, and type of the power stations, getting into account the electricity demand (Hobbs, 1995). Nowadays the electricity planning is becoming more complex, with the growing share of renewable energy sources (RES), some of them with variable output contributing to this increasing complexity. Great investments and costs are committed on the construction of new power stations, on their operation and maintenance, and on the operation and maintenance of the existing ones. Using optimization models may be seen as a huge advantage in the minimization of inherent costs, leading to a more efficient electricity system. Naturally, electric utilities become one of the earliest users of optimization methods applied to optimization electricity planning models (Hobbs, 1995).

Long-term horizon planning frequently addresses the generation expansion planning problem and envisages supporting strategic decision making. In fact, the generation expansion planning is highly addressed in the literature, with the main concern of finding the least cost expansion plan, according to the characteristics of each electricity system (Tekiner et al., 2009). However nowadays, CO_2 emission control and reduction is assuming an increasing role in energy decisions and support policies. Figueira et al. (2005) recognized the importance of energy decisions based on the economic dimension, but, according to the authors, power planning optimization requires usually not only the total expansion cost minimization, but also environmental impacts minimization. Also, Cai et al. (2009) underlined the importance of the environmental aspects latent on the electricity decision making, along with other concerns such as fossil fuel increasing prices, reliability, and security of supply, for long seen as ongoing challenges faced by decision makers around the entire world.

2.2.1 Optimization models for power planning

According to Hobbs (1995), optimization models are usually used to resource and equipment planning, with a time range between ten to forty years. The objective of these optimization models is to obtain the least cost mix generator addictions and decommissioning, taking into account electricity demand forecasts, investment costs and fuel prices. Optimization models for generation expansion planning are therefore seen as useful and powerful tools to many decision makers. The complexity of the optimization model results from the diversity of technologies available to systems expansion, the temporal and/or spatial evolution of parameters included in the model, and the environmental and social arguments that need to be integrated (Li et al., 2010). Generation expansion planning allows to identify the most adequate technology and expansion size, taking into account economic criteria, and ensuring at the same time that the installed capacity follows the expected demand growth (Pereira and Saraiva, 2010). In line with this, Meza et al. (2009) support that the generation expansion planning aims to determine the best solution for future generation utilities, recognizing that wrong decisions will result in a loss of a large amount of money. To meet the increasing demand, new generation utilities will be needed. This requires large investment and operating costs, and the generation expansion planning models aim to minimize the social costs of electricity, including environmental and financial costs.

Different approaches to solve the problem of the generation expansion planning can be seen over the literature. Associated to these different approaches are different techniques that encompasses multi-objective algorithms, bender's decomposition algorithms, stochastic programming, mixed integer programming (MIP), dynamic programming, genetic algorithms, linear programming and particle swarm optimization.

In a previous study, Linares and Romero (2000), proposed and applied an electricity power planning model for Spain including already multiple economic and environmental objectives. Although a large set of general optimization models have been proposed to tackle the generation expansion problem, it is evident that each model has to be adapted to the particular characteristics of the system under analysis taking into account technical, geographical, political, legal, and environmental restrictions. This led authors to develop and apply particular models that easily describe the underlying problem and conduct the intended simulations. See, for example, Meza et al. (2009), presenting a single-period multi-objective mixed-integer nonlinear generation expansion planning designed for the case of the Mexican power system or Tekiner et al. (2010) describing also a multi-objective generation expansion planning over a multi-period planning horizon of 15 year. Other studies considering multi-objective programming can be seen in Celli et al. (2005) and Heinrich et al. (2007). A bi-level generalized Benders' decomposition model to solve generation expansion planning is presented in Bloom et al. (1984). In their work, authors calculate production costs and system reliability in the problem second-level, and then results are applied in the first level, master problem, to calculate power units expansion plan. Also Rebennack (2014) applied a bender's decomposition algorithm for the Panama's power system. Investment decisions are calculated in the master problem while the second level deals with the emissions and power units schedule problems.

Along with the demand, both wind and hydro uncertainty turns the task of generation expansion planning model increasingly harder. Stochastic programming (SP) despite the complexity that brings to the models is frequently used to deal with this problem (Manabe et al., 2014). For example Askari et al. (2013) addressed in their work the problem of demand uncertainty for the electricity sector investment problem resorting to SP in an optimization model. Also Pantoš (2013) presented a stochastic generation expansion planning for the electricity power system and natural gas system. In AlRashidi and EL-Naggar (2010), particle swarm optimization was used for peak load demand forecast. Applied to Kuwait and Egyptian networks, peak load forecast will allow to minimize the error associated with the estimated model parameters and therefore a more reliable generation expansion plan can be obtained.

Moghddas-Tafreshi et al. (2011) addressed in their work the complexity of generation expansion planning in competitive environments. In their study, a particle swarm optimization method was also used to find the best investment solution for each generation company. In the same way Pereira and Saraiva (2011) also enhanced the difficulties of generation expansion planning in a competitive environment. However in this case a genetic algorithm was used. An improved genetic algorithm was also developed and used in Park et al. (2000) to solve a least costs generation expansion planning for a fourteen and twenty four year time horizon.

Other techniques have been used by other authors to solve the generation expansion planning. For example, Yildirim et al. (2006) presented a simulated annealing genetic algorithm for a least cost optimization problem. A case study with seven types of generating units and a 20 years planning horizon was considered and applied to Turkey's power system. Similar studies using simulated annealing were previously used in Zhu and Chow (1997) and Wu et al. (2004).

The objective of this chapter was not to present an exhaustive revision of the literature, but rather showing the importance of optimization models for electricity generation planning and the diversity of approaches used by different authors to deal with such complex problem. Next section, aims to demonstrate how these models are frequently used also to deal with the analysis of RES integration in the power systems.

2.2.2 RES integration in power planning

The integration of high levels of RES in the power system is changing the way society looks for electricity power planning, moving from a centralized perspective of the electricity sector to a more close to load centers perspective (Sarafidis et al., 1999). Allied to this paradigm change, and regarding to the increasing level of RES in the electricity system, economic concerns and the increase of public awareness regarding the environmental concerns are key focus for the nowadays generation expansion planning problem. In fact, according to Erdinc and Uzunoglu (2012), combining RES such as, wind, solar, hydro, etc. with traditional sources may lead to a more economic, environmental friendly and reliable electricity system. Also Hafez and Bhattacharya (2012), recognize the increasing importance that is being given to the RES integration. In their work the authors have used the HOMER tool for the design, planning, sizing and operation of a hybrid microgrid, assessing the impacts, in terms of life cycle costs and environmental emissions. Also Sadeghi et al. (2014) have enhanced the importance of RES power units as an alternative to traditional ones, in order to reduce greenhouse gases emission. In their study a generation expansion problem is addressed to evaluate the impact of RES penetration in the electricity system under a feed-in tariff scheme. Results show that RES have in fact a positive impact in both greenhouse gases emission and in the acceptance of generation companies to invest in RES. In Biswal and Shukla (2014) a least cost generation expansion planning model is presented in order to meet the future electricity needs in a more economical, environmental, and social acceptable way. With this work, the authors aim to assess the economic impacts of large scale integration of wind in the system. In Gil et al. (2014) a stochastic generation expansion planning for the Chilean system is developed. A mixed integer programming model, taking into account hydro uncertainty is considered and PLEXOS tool used to obtain the simulation results. Results show a reduction between 1.3% and 1.9% on the investment and expected operational costs when comparing with a deterministic approach. Saxena et al. (2014) presented a stochastic model for both generation and transmission expansion planning, taking into account the solar power generation uncertainty. Results show that using solar generation will result in a reduction of both thermal power units investment and average operation and production costs.

Despite the benefits, mostly environmental ones, the integration of RES implies addressing some concerns, essentially due to the impacts that renewable source may have in the operation of power system (Leung and Yang, 2012). These impacts lie essentially in the high variability of most renewable resources, with wind in the line of front on this issue. For example in Liu et al. (2011), the authors assessed the capacity of the Chinese energy system to integrate higher levels of wind power. For that, the EnergyPLAN tool, was used, and the maximum wind power capacity that guarantees the system feasibility determined. Conclusions led to three main strategic solutions to mitigate the impacts of large wind power capacity integration, being these solutions the increasing mix of power generation technologies, the combination of heat pumps with heat storage devices to apply on district heating and the bet on the development of the electric vehicles. Jahromi et al. (2012) presented in their work a multi-objective model for distributed generation expansion planning. A fuzzy approach is proposed with the aim of minimize total costs, emissions and voltage profile. The model is therefore applied to different studies accessing its effectiveness. For example in Karunanithi et al. (2014), the authors present a generation expansion planning model applied to an Indian state and considering a period of 30 years. The impacts of RES integration, mainly wind and solar, along with reliability, loss of load probability, and energy not served criteria are assessed for different RES penetration levels. Results show that an increase of RES, 20% beyond the total installed capacity, will result in a loss of reliability and therefore to an increase of investment costs due to the need to invest in back up capacity to maintain the system reliability.

The use of optimization models applied to the generation expansion planning problem seems to be essential, even more when RES are getting increasing importance. The complexity added to the power systems with the integration of RES is evident, and usually associated to problems such as, small investments towards improving and extending the electricity infrastructure, backup systems geographically too remote from the potential power sites or currently financially infeasible and the difficulties associated to the operation of thermal power units (Li et al., 2012). Therefore, the use of optimization models becomes essential to identify and mitigate these problems, resulting on a more trustful integration of RES in the power system.

In the following sections a multi-objective MILP generation expansion planning is introduced in detail with the final aim of attesting its application to a mixed hydro-thermal-wind power system. The model is built in an incrementally and centrally planned perspective. The Portuguese system analysis was addressed as a case study representing the starting point for the problem. In fact, the Portuguese system matches perfectly in typical problems like the one addressed in this work. Economic and environmental criteria are included in the objective functions, aiming to minimize total generation costs and environmental impacts. Economic aspects comprise investment and operation costs of power generation units, while environmental ones comprise the minimization of greenhouse gases emission, specifically CO_2.

2.3 Model formulation

2.3.1 Objective functions

The proposed model formulation takes into account both the economic and environmental cost. Two objective functions are considered. The first objective function concerns the economic cost measured in € and is defined by

$$\sum_{t\in T}\sum_{n\in N}\left[\left(Ic_n\frac{j(1+j)^{lt_n}}{(1+j)^{lt_n}-1}+CFOM_n\right)Ip_{n,t}(1+j)^{-t}\right]+$$
$$\sum_{t\in T}\sum_{m\in M}\sum_{i\in I}\left[\left(CVOM_i+F_i+Cp_i+EC\times CO_{2_i}\right)P_{i,m,t}\Delta_m(1+j)^{-t}\right], \quad (2.3.1)$$

where T is a set of the time period (in years) considered in the model, N is a set of the new power plants to be included in the system, M is the set of months per year of planning, I is the set of all power plants, Ic_n is the n new power plant investment cost (€/MW), j is the annual discount rate, lt_n is the n new power plant lifetime (years), $CFOM_n$ is the Operation and Management (O&M) fixed cost of the n type of power plant (€/MW), $Ip_{n,t}$ is the installed power of plant n in year t (MW), $CVOM_i$ is the variable O&M costs for each i type of power plant (€/MWh), Cp_i is the cost of pumping for each i type of power plant (€/MWh), F_i is the fuel cost for each i type of power plant (€/MWh), EC is the CO_2 emission allowance cost (€/ton), CO_{2_i} is the CO_2 emission factor of type i power plant (ton/MWh), $P_{i,m,t}$ is the power output from power plant i in month m of year t (MW), and Δ_m is the number of hours for month m.

This objective function is set up by the sum of fixed and variable costs. The fixed costs are related to both the investment cost of the new power plants and to all fixed O&M costs. The capital investment cost is obtained through the sum of annuities over the planning period, assuming the uniform distribution of the investment cost during the plant lifetime. This approach, although not taking into account the possibility of the accelerated depreciation of technologies, is commonly used for the computation of the levelized cost of electricity for mature technologies in relatively stable markets, as it is assumed in this analysis. Also, being the candidate power technologies already mature, with the exception of offshore wind power, changes on the future O&M costs were assumed to be negligible for the ten years planning period. In addition these costs are far from being the determinant ones, as investment and fuel are the major cost drivers. In what concerns to variable costs, those encompass the variable O&M costs, the fuel and pumping costs, and CO_2 emission allowance costs for each power plant.

The second objective function represents the environmental burden, measured in tons of CO_2 emission of the system. The objective function is defined by

$$\sum_{t \in T} \sum_{m \in M} \sum_{i \in I} CO_{2_i} P_{i,m,t} \Delta_m. \tag{2.3.2}$$

This objective function is described as the sum of the total CO_2 emissions released from all power plants during the entire planning period.

2.3.2 Constraints

The set of adopted constraints for the electricity sector planning problem usually includes constraints derived from physical processes, demand requirements, capacity limitations, and legal/policy impositions. These constraints are described as equations imposing conditions to the model formulation and by this defining values of the decision variables that are feasible (Hobbs, 1995).

Demand constraint

The total power generation from all power units must meet the system load demand at each month of each year of the planning period, including the pumping consumption. The mathematical formulation of these constraints is

$$D_{m,t} - PSRP_{m,t} \leq \left(\sum_{s \in S} P_{s,m,t} - \sum_{p \in Pump} P_{p,m,t} \right) \Delta_m, \qquad \forall m \in M, \forall t \in T, \tag{2.3.3}$$

where $D_{m,t}$ is the demand in month m of year t (MWh), $PSRP_{m,t}$ is the production of other renewable power plants (non-large hydro and non-wind) and co-generation in month m of year t (MW), S is the set of all power plants except pumping units, and $Pump$ is a set of all pumping power units.

Power capacity constraints

For each month of each year during the entire planning period, the power output of each power plant must be less or equal to the available installed power. The availability factor of each thermal power plant was assumed as constant for each month during all the years included in the planning. This availability factor ranges from 92% for coal and fuel oil power plants, to 94% for CCGT power plants (Kehlhofer et al., 2009). The assumed constraints were defined for existing and new power units in the system. The first one is related to existing power units and is defined by

$$P_{e,m,t} \leq \varphi_{e,m} \times Ip_{e,t} \qquad \forall e \in T\_E, \tag{2.3.4}$$

where $\varphi_{e,m}$ is the availability factor of power unit e on month m, $Ip_{e,t}$ is the installed power of unit e on year t, T_E is the set of all existent thermal power plants.

The second set of constraints is related to new power units and is defined by

$$P_{n,m,t} \leq \varphi_{n,m} \times Ip_{n,t} \qquad \forall n \in T\_N, \tag{2.3.5}$$

where T_N is the set of all new thermal power plants and $\varphi_{n,m}$ is the availability factor of power unit n on month m.

Renewable constraint

Renewable constraint enforce the model to ensure at least a pre-defined minimum level of electricity generation from renewable energy sources. The mathematical formulation of the constraint is given in the following equation.

$$\begin{aligned} \sum_{m \in M} \Bigg[dp \times PSRP_{m,t} + \sum_{e \in E\_Wind} P_{e,m,t} \times \Delta_m + \sum_{n \in N\_Wind} P_{n,m,t} \times \Delta_m + \\ \sum_{e \in E\_Hydropower} P_{e,m,t} \times \Delta_m + \sum_{n \in N\_Hydropower} P_{n,m,t} \times \Delta_m \Bigg] \\ \geq share_r \times \sum_{m \in M} D_{m,t} \qquad \forall t \in T, \end{aligned} \tag{2.3.6}$$

where dp is the share of renewable SRP (SRP-Special Regime Production comprises renewable power producers, excluding large hydro and wind power plants, and renewable and non-renewable cogeneration plants), $share_r$ is the goal for renewable energies, and N_Wind and E_Wind are the sets of the new and existent wind power plants, respectively.

Wind constraints

These constraints ensure wind power generation capacity to be equal to the total installed power taking into account the monthly wind availability. These constraints are set as equalities assuming that wind power is not subject to dispatch, benefiting from feed-in tariffs and priority access to the grid. These set of constraints are described by

$$P_{n,m,t} = \varphi_{n,m} \times Ip_{n,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall n \in N\_Wind \tag{2.3.7}$$

and

$$P_{e,m,t} = \varphi_{e,m} \times Ip_{e,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall e \in E\_Wind. \tag{2.3.8}$$

It is also necessary to ensure that wind power potential will be kept between proper values, achieved by imposing the following bound constraints.

$$Ip_{n,t} \leq ONV \qquad \forall t \in T, \quad \forall n \in N\_Onshore, \tag{2.3.9}$$

where $N\_Onshore$ is the set of wind onshore power plants, ONV is the maximum onshore wind potential value (MW), and

$$Ip_{n,t} \leq OFV \qquad \forall t \in T, \quad \forall n \in N\_Offshore, \tag{2.3.10}$$

where $N\_Offshore$ is the set of wind offshore power plants and OFV is the maximum offshore wind potential value (MW).

Large hydro constraints

For the large hydropower plants with reservoir, constraints regarding the expected storage and production capacity for each month of each year of planning period are included into the model, where power pumping is also considered. The following equation relates the reservoir level for the next month in terms of the previous reservoir level, inflows and consumption. Two sets of constraints appear due to the transition between December and January of consecutive years.

$$reserve_{1,t} = reserve_{12,t-1} + Inflows_{1,t} \times \left(\frac{(Ip_{n,t} + Ip_{e,t})}{Ip_{e,t}}\right) - \left(\sum_{n \in N\_Hydroreserve} P_{n,1,t} + \sum_{e \in E\_Hydroreserve} P_{e,1,t}\right) \times \Delta_1 + \sum_{p \in Pump} \eta_p * P_{p,1,t} \times \Delta_1 \qquad \forall t \in T \setminus \{1\}, \tag{2.3.11}$$

where $reserve_{m,t}$ is the reservoir level on month m of the year t, $Inflows_{m,t}$ is the hydro inflow on month m of the year t, $N\_Hydroreserve$ are all new hydropower units with reservoir, $E\_Hydroreserve$ are all existing hydropower units with reservoir and η_p is the efficiency of pumping units, usually around 70%.

$$reserve_{m,t} = reserve_{m-1,t} + Inflows_{m,t} \times \left(\frac{(Ip_{n,t} + Ip_{e,t})}{Ip_{e,t}}\right) - \left(\sum_{n \in N\_Hydroreserve} P_{n,m,t} + \sum_{e \in E\_Hydroreserve} P_{e,m,t}\right) \times \Delta_m + \sum_{p \in Pump} \eta_p * P_{p,m,t} \times \Delta_m \qquad \forall t \in T, \forall m \in M \setminus \{1\}. \tag{2.3.12}$$

Additional upper and lower bounds must be used to define maximum and minimum reservoir levels, represented in the following sets of constraints.

$$reserve_{m,t} \leq maxR_{m,t} \qquad \forall t \in T, \quad \forall m \in M, \tag{2.3.13}$$

$$reserve_{m,t} \geq minR_{m,t} \qquad \forall t \in T, \quad \forall m \in M, \tag{2.3.14}$$

$$maxR_{m,t} = maxReservoir \times \left(\frac{(Ip_{n,t} + Ip_{e,t})}{Ip_{e,t}}\right) \quad \forall t \in T, \quad \forall m \in M, \quad \forall n \in N\_Hydroreserve, \quad \forall e \in E\_Hydroreserve \tag{2.3.15}$$

$$minR_{m,t} = 0.2 \times maxR_{m,t} \qquad \forall t \in T, \quad \forall m \in M, \tag{2.3.16}$$

where $maxR_{m,t}$ and $minR_{m,t}$ are the maximum and minimum reservoir level allowed, respectively and $maxReservoir$ is the maximum capacity of reservoir measure in MWh.

The next set of constraints ensures that the production of run-of-river power plants is kept equal to the installed power, taking into consideration the average monthly availability of these units. This type of plants are characterized by a reduced storage capacity.

$$P_{n,m,t} = \varphi_{n,m} \times Ip_{n,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall n \in N\_Hydrorr, \tag{2.3.17}$$

where $N\_Hydrorr$ is the set of new run-of-river hydropower plants.

$$P_{e,m,t} = \varphi_{e,m} \times Ip_{e,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall e \in E\_Hydrorr, \tag{2.3.18}$$

where $E\_Hydrorr$ is the set of existing run-of-river hydropower plants.

The next set of constraints ensures a minimum share of the new run-of-river power plants on the hydropower system under analysis.

$$\sum_{n \in N\_Hydrorr} Ip_{n,t} \geq share_{rr} \times \sum_{n \in N\_Hydropower} Ip_{n,t} \qquad \forall t \in T, \quad \forall m \in M. \tag{2.3.19}$$

Pumping constraints

For the mathematical formulation of the operation of hydropower plants with pumping capacity, two reservoirs must be taken into account. The upper one storages water from inflows and from pumping itself, while the lower one storages water already used for electricity generation that may be pumped again later to the upper level. Again two set of constraints are necessary to model the year transition from December to January for consecutive years. The model set of constraints related with pumping follows.

$$pumping\_reserve_{1,t} + dump_{1,t} = pumping\_reserve_{12,t-1} + \left(\sum_{n \in N\_Hydroreserve} P_{n,1,t} + \sum_{e \in E\_Hydroreserve} P_{e,1,t} \right) \times \Delta_1 - \sum_{p \in Pump} \eta_p \times P_{p,1,t} \times \Delta_1 \qquad \forall t \in T \setminus \{1\}, \quad (2.3.20)$$

where $pumping\_reserve_{m,t}$ is the reserve of the pumping storage hydropower plant in month m, of the year t, and $dump_{m,t}$ is the pumping reservoir energy dump, i.e., all unusable pumping energy in month m of the year t when max pumping reserve level is reach due to lack of pumping need.

$$pumping\_reserve_{m,t} + dump_{m,t} = pumping\_reserve_{m-1,t} + \left(\sum_{n \in N\_Hydroreserve} P_{n,m,t} + \sum_{e \in E\_Hydroreserve} P_{e,m,t} \right) \times \Delta_m - \sum_{p \in Pump} \eta_p \times P_{p,m,t} \times \Delta_m \qquad \forall t \in T, \quad \forall m \in M \setminus \{1\}. \quad (2.3.21)$$

Constraints on the upper and lower bounds on the pumping reservoir must also be included to ensure reliability of system, which are represented by the following constraints.

$$pumping\_reserve_{m,t} \geq min\_pumping\_reserve \qquad \forall t \in T, \quad \forall m \in M, \quad (2.3.22)$$

and

$$pumping\_reserve_{m,t} \leq max\_pumping\_reserve \qquad \forall t \in T, \quad \forall m \in M, \quad (2.3.23)$$

where $min\_pumping\_reserve$ and $max\_pumping\_reserve$ is the minimum and maximum level for the pumping reserve, respectively.

The next three sets of constraints ensure the reliability of pumping units. For each time period the energy pumped cannot be higher then the pump capacity, represented in the first two sets of constraints, or higher than the maximum capacity of the lower reservoir, represented by the third set of constraints.

$$P_{e,m,t} \leq \varphi_{e,m} \times Ip_{e,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall e \in E\_Hydropump, \tag{2.3.24}$$

where $E\_Hydropump$ is the set of existent large hydropower plants with pumping capacity.

$$P_{n,m,t} \leq \varphi_{n,m} \times Ip_{n,t} \qquad \forall t \in T, \quad \forall m \in M, \quad \forall n \in N\_Hydropump, \tag{2.3.25}$$

where $N\_Hydropump$ is the set of new large hydropower plants with pumping capacity.

$$\sum_{n \in N\_Hydropump} P_{n,m,t} \times \Delta_m \leq max\_pumping\_reserve \qquad \forall t \in T, \quad \forall m \in M. \tag{2.3.26}$$

This last set of constraints imposes a minimum level of installed pumping power for each MW of installed wind power added to the system. This is a fundamental element of the model as it ensures hydro complementarity with wind resources, which strongly contributes to the reliability of the electricity supply by reducing the impacts of the wind power volatility on the electric system.

$$\sum_{n \in N\_Hydropump} Ip_{n,t} + \sum_{e \in E\_Hydropump} Ip_{e,t} \geq \frac{\sum_{e \in E\_Wind} Ip_{e,t} + \sum_{n \in N\_Wind} Ip_{n,t}}{\beta}, \qquad \forall t \in T. \tag{2.3.27}$$

where β is a constant that reflects the relationship between pumping and wind installed power.

Capacity constraints

For thermal power units, a capacity constraint is used to relate the total modules number with the installed power.

$$Ip_{n,t} = number\_units_{n,t} \times mc_n \qquad \forall n \in T\_N, \tag{2.3.28}$$

where $number\_units_{n,t}$ is the number of new installed thermal units set as the only integer variable of model and mc_n is the capacity of each new considered module.

Additionally, the following constraints imposes that the $Ip_{n,t}$ is increasing during the planning period.

$$Ip_{n,t} \geq Ip_{n,t-1} \qquad \forall t \in T \setminus \{1\}, \forall n \in I. \tag{2.3.29}$$

Reserve constraints

The reserve set of constraint ensures the security of the system, taking into account the non-usable capacity, which includes the capacity that cannot be scheduled due to reasons like the temporary shortage of primary energy resources, affecting in particular the hydro and wind power plants (for a detailed description please refer to Ferreira (2008)).

$$\begin{aligned} RM\left(\sum_{n \in I\_N} Ip_{n,t} + \sum_{e \in I\_E} Ip_{e,t} + IPsrp_t\right) \leq \sum_{n \in I\_N} Ip_{n,t} + \sum_{e \in I\_E} Ip_{e,t} + IPsrp_t - \\ (LW \times (\sum_{n \in N\_Wind} Ip_{n,t} + \sum_{e \in E\_Wind} Ip_{e,t}) + LH \times (\sum_{n \in N\_Hydropower} Ip_{n,t} + \sum_{e \in E\_Hydropower} Ip_{e,t}) + \\ LSRP \times IPsrp_t + LBHG + LBTG - Pl_t) \qquad \forall t \in T \end{aligned} \tag{2.3.30}$$

where I_N and I_E are the set of all new and existent power units respectively, RM is the reserve margin of system, $IPsrt_t$ is the installed power of SRP in year t, LW is the potential reduction of wind power due to the lack of wind, LH is the potential reduction of hydropower due to a dry regime, $LSRP$ is the potential loss of SRP due to an unfavorable regime and $LBHG$ and $LBTG$ represent the lost of biggest hydro and thermal power groups. Pl_t is the system peak load on year t. Using this restriction, the model, explicitly takes into account the impact that the increasing hydro and wind capacity, will have on the RM requirements.

2.4 Model implementation and results analysis

2.4.1 Case study

The optimization model previously described was designed with the final aim of being used for the analysis of a mixed hydro-wind-thermal power system. For this case study, a typical system encompassing all the electricity power generation technologies referred above, was taken into consideration. The particular case of the Portuguese electricity system was then selected, as representative of an example of this technology mix. Despite of the chosen case, the conclusions reached out should be valuable and useful for policy makers having to deal with strategic power planning in a system combing thermal, hydro, and wind power, strongly constrained by the seasonal availability of the hydro and wind power.

In fact, in the end of 2013, Coal, CCGT, and large hydropower plants were the major contributors of Portuguese electricity production with a total installed power of approximately 1756MW, 3829MW, and 5239MW, respectively. However, the role of non large hydro renewable sources is increasing. Wind power, in particular, reached 4368 MW in 2013 (REN, 2013b) and is expected to keep on this increasing trajectory at least until 2022 (REN, 2013a). The herein described planning model requires the present situation of the electricity system under study, along with the technical constraints. In particular, RES minimum production levels were defined according to EU directives and goals, and a minimum relationship between pumping and wind power was imposed, in order to smooth the wind power variable output. Thus, and for the Portuguese case under analyses, for each 3.5 MW of wind power capacity 1 MW of pumping capacity is foreseen (INAG, 2007).

In order to reduce the complexity of the analysis, a closed system was assumed, i.e, electricity imports and exports were not accounted in the model. This way, analysis will look for optimal electricity plans to meet the internal demand at minimum generation cost. Furthermore, and according to REN (2013a), it is assumed a 1.1% annual growth rate of electricity demand. The natural gas prices are assumed to increase 1.4% per year and the coal prices are assume to increase 0.8% per year, according to the IEA (2012) current policies scenario.

The variables used for the optimization problem were the production of all existent and new power units in month m of year t, the installed power of all new power units in year t, the total storage energy in month m of year t of lower and higher reservoir (hydro reserve and pumping reserve), the dump of energy in month m of year t and finally, the only integer variable, the total number of thermal units. On the other hand, the installed power of existent units was treated as parameters (Coal 628 MW, Gas 3824 MW, Wind 4194 MW, and Hydro 5239 MW).

2.4.2 Used approach and numerical results

Our proposed model was coded in GAMS (2011). The CPLEX solver was selected to obtain the numerical results reported herein. The CPLEX solver is interfaced with GAMS and proved to be successfully used by other authors in similar modeling optimization problems (Kamalinia and Shahidehpour, 2010). The numerical results were obtained in a Microsoft Windows operating system using a Intel® CORE™i5-2410M CPU @ 2.3GHz computer with 4GB of memory.

A multi-objective problem with a single period of ten years horizon was considered for the electricity planning of mix thermal-wind-hydropower system. Despite the typical one year or longer time step used for the long-term horizon generation expansion planning models, this work follows a set of 12 aggregated monthly load blocks which allows to consider in a more reliable way the seasonality of both the RES resources and of the demand. The model assumes then average operating conditions for each month. The short-term impacts, that might be particularly relevant for large wind power scenarios, are not explicitly included in the model but the predicted wind seasonality obtained from the monthly availability factor along with the RM formulation (see equation (2.3.7), (2.3.8), and (2.3.30)) already allows taking into account the uncertainty of wind availability. In addition, the hydro system is also expected to provide backup capacity that should smooth these impacts, resourcing to the pumping units as described by equation (2.3.27). Both these set of constraints represent the system stability criteria of the model.

The multi-objective problem was addressed by solving single-objective optimization problems. Firstly a single-objective optimization problem was solved for each objective function reported in equations (2.3.1) and (2.3.2), using equations equations (2.3.3)– (2.3.30) as constraints. For our case study the single objective optimization problem represents a mix integer linear optimization problem (MILP) with 2912 continuing variables, 50 integer variables, and 3603 constraints. These single-optimization problems are named as $R0$ and $R9$, for the objective function (2.3.1) and (2.3.2) respectively, and represent the extreme solutions of the multi-objective model. The results of this initial exercise are presented in Table 2.1 detailing the total cost and emissions for the entire planning period, together with the cost and emissions per MWh and the computation time to obtain each solution.

In addition to the single-objective minimization of the costs and emissions, and in order to provide some insights about the multi-objective problem, 8 additional optimization problems named from $R1$ to $R8$, were considered. These optimization problems represent different scenarios and allow to design the Pareto front, presented in Figure 2.1. These results were obtained by minimizing the cost objective function described in Equation (2.3.1) while Equation (2.3.2) was included as a constraint, i.e., the amount of CO_2 emissions were constrained to 8 pre–selected values. The extreme points correspond to solutions presented in Table 2.1, while the intermediate results correspond to the solutions of the CO_2 emissions constrained problems.

A first inspection of the presented Pareto fronts clearly reveals that the used objective functions are divergent under the assumed conditions of the system and a cost reduction will largely induce an increase in the CO_2 emissions.

An analysis of Figure 2.1 allows to conclude that the decrease of CO_2 emissions negatively influences the cost of the electricity generation system, but this relationship is not linear. The results indicate that the slope of the curve

Table 2.1: Optimal objective functions solutions

		Cost (M€)	CO_2 (Mton)	Cost (€/MWh)	CO_2 (ton/MWh)
Optimal cost solution	R0	7640.84	171.88	14.638	0.329
Optimal emission solution	R9	16146.11	10.36	30.9	0.02

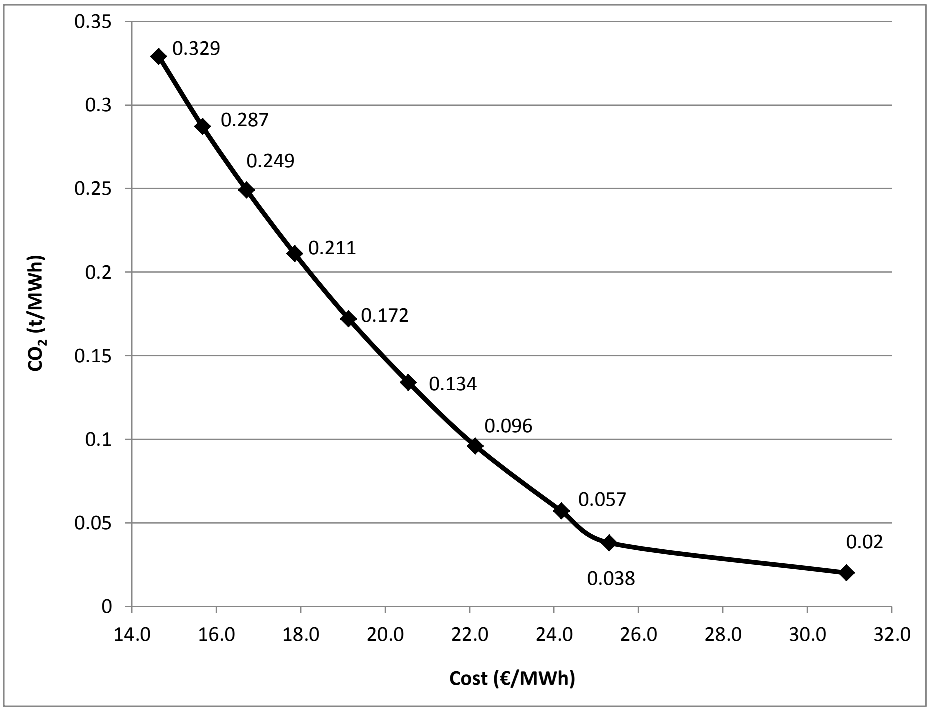

Figure 2.1: Pareto curve solutions for the MILP

is much higher for the points on the left hand side than for the points close to the right hand side, meaning that the first CO_2 emission gains are less expensive to achieve.

Table 2.2 describes the evolution of the installed power of different technologies when reduction on CO_2 emissions are included in the model. A reduction of the new coal power plants may be observed as the emission limits are getting more restrictive. On the other hand, investments in new CCGT power plants follow an opposite pattern, increasing as the CO_2 emissions limits are reduced. Investments in new CCGT power plants leads to higher production costs ensuring both demand and environmental requirements. For the first solutions of the optimization problems ($R1$, $R2$, and $R3$), the CO_2 levels are then mainly achieved through the replacement of coal power electricity production by CCGT, hydro and wind electricity production. This substitution brings considerable environmental gains. It should be stressed that hydro potential is reached at solution $R1$ and so, for solutions closer to the right hand side of the graph, CO_2 reductions may only be achieved by increasing investments on wind power (onshore and offshore) and reducing CCGT production and investments. Although some CO_2 reductions are achieved, those are much costlier than the ones obtained for the initial ranges of the curve. This can be observed at the solution point $R8$, where the kink of curve occurs, originating a significant increase on cost of avoided emissions from average 36.7 €/ton obtained in the left hand side of Figure 2.1 to average 304.3 €/ton on the right side of same graph.

Although wind power may displace part of the electricity generated by large thermal power plants, it has a limited capacity to displace conventional installed power. For example, between the optimal cost solution $R0$ and $R7$ an increase of 4405MW of the total installed wind power is observed, however the thermal power is reduced by only 1552MW, with the total replacement of investment in new coal power units by the investment in new gas units. Being wind power a technology of variable output its contribution to the security of supply in peak moments is low as reflected in the reserve margin restriction (Equation (2.3.30)). For the scenario with minimum emissions ($R9$) the total electricity production exceeds the electricity demand mainly due to the increase of wind power in the system. This is particularly evident during the winter months when the availability of both hydro and wind resources achieve the highest values and as such the monthly non-dispatchable production overcomes the total electricity demand.

As a general result, the contribution of renewable sources to CO_2 emission reduction must be underlined. The hydropower and in particular wind power electricity generation tend to increase as the emissions restrictions get higher, resulting in two important aspects: the increase of the RES share and the reduction of the external energy dependency of the country.

Table 2.2: Installed power and contribution for electricity in the 10^{th} year of planning

	R0	R1	R2	R3	R4	R5	R6	R7	R8	R9
					Total Installed Power (MW)					
Coal (new)	2400	1000	400	-	-	-	-	-	-	-
Coal (existing)	628	628	628	628	628	628	628	628	628	628
Gas (new)	-	-	1010	1858	2020	2020	1858	848	1010	2868
Gas (existing)	3824	3824	3824	3824	3824	3824	3824	3824	3824	3824
Wind (new)	-	-	-	-	-	-	983	4405	4429	5529
Wind (existing)	4194	4194	4194	4194	4194	4194	4194	4194	4194	4194
Hydro (new)	124	4646	4646	4646	4646	4646	4646	4646	4646	4646
Hydro (existing)	5239	5239	5239	5239	5239	5239	5239	5239	5239	5239
SRP	3710	3710	3710	3710	3710	3710	3710	3710	3710	3710
Total	20303	23425	23835	24283	24445	24445	25266	27678	27864	30822
					Contribution for electricity demand (%)					
Coal (new)	34.3%	13.8%	5.9%	0%	0%	0%	0%	0%	0%	0%
Coal (existing)	7.7%	7.7%	7.7%	0%	0%	0%	0%	0%	0%	0%
Gas (new)	0%	0%	13.2%	24.8%	26.9%	26.9%	23.7%	10.6%	12.6%	8.5%
Gas (existing)	0.8%	10.1%	5.3%	6.2%	3.7%	3.7%	1.6%	1.8%	0%	0%
Wind (new)	0%	0%	0%	0%	0%	0%	4.6%	20.5%	20.7%	25.4%
Wind (existing)	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%	20.1%
Hydro (new)	0.3%	10.3%	14.4%	15.9%	16.1%	16.8%	21.7%	12.9%	12.4%	24.3%
Hydro (existing)	15.5%	16.6%	12%	11.7%	11.9%	11.2%	7%	12.8%	12.9%	6%
SRP	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Share of RES[1]	46.7%	57.8%	57.4%	58.5%	58.9%	58.9%	64.2%	77.1%	76.9%	86.1%
Energy dependence[2]	53.3%	42.2%	42.6%	41.5%	41.1%	41.1%	35.8%	22.9%	23.1%	18.8%

[1]Assuming that 10.5% is renewable energy from SRP;

[2]Assuming that 10.5% is non-renewable energy from SRP;

2.4.3 Wind power sensitivity analyses

The optimization procedure aims to reduce a very large number of possible plans, to a small number of optimal plans that are to be presented to decision makers. However, the solutions found represent the optimal point from a pure mathematical perspective and the decision maker should not disregard other solution that, although not being optimal, may present other considerable advantages with a small cost increase.

Figure 2.1 presents the optimal solution from the mathematical point of view, considering the two main objectives of the model. In fact, cost and emissions trade-off analysis leave aside important aspects such as the external energy dependency or the need to diversify the fuel mix of the system under analysis. The results also indicate that for the majority of the obtained optimal solutions the wind power is far from achieving the full estimated potential. It seems then important to explore the possibility of different onshore wind scenarios, analyzing other plans that although not being Pareto optimum may be interesting from the strategic decision making perspective.

The plot presented in Figure 2.2 provides the results of imposing to the system a predefined value for the total installed wind power. As an illustrative example, this simulation was conducted for scenario $R3$ for which the total amount of CO_2 emissions during entire planning period must be less or equal to 110Mton. New solutions were obtained with higher costs and consequently moving away from the original Pareto line.

Setting the values for the new installed onshore wind power equal to 1000, 1500, 2000, 3000, 4000 and 4429MW leads to higher costs. As such, the increase of wind power on the system would not lead to a reduction of CO_2 emissions but rather to a change on the fossil fuel power technologies contribution. When comparing these results to the original $R3$ solution, it can be observed a reduction of the electricity generated from CCGT. On the other hand the electricity production from coal would increase. An increase of the CO_2 allowance cost could change the relative cost structure of CCGT and coal power plants and by this inducing both cost and CO_2 reductions. These new solutions present higher costs and no changes on CO_2 emissions values, comparatively to $R3$, but the contribution to both a reduction of the external energy dependency of the electricity sector and to an increase of the share of electricity produced from RES should not be overlooked in systems highly dependent of imported fuel sources. For example, imposing 4000MW of new installed wind power during the planning period, would result in a solution 21% more expensive than the original $R3$. However, it would be possible to reduce the external dependency of the electricity generation sector by 5.5% and the share of RES would increase by the same amount, comparatively to the optimal values reported under $R3$. Furthermore, for high wind power scenarios the electricity production can exceed the

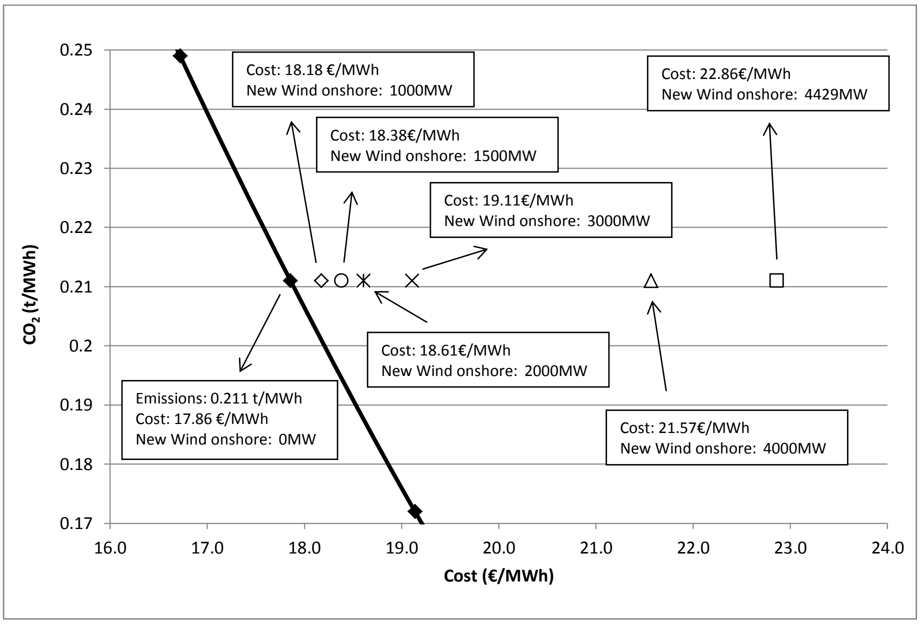

Figure 2.2: Wind power simulation for $R3$ solution

demand projections demonstrating the potential for electricity exportations in an integrated market.

The integration of RES technologies, despite of all the usually attributed environmental advantages, can in fact increase the complexity of the models, turning more difficult the tasks of grid managers. The use of optimization methods supported by sensitivity analysis can be a powerful and huge help to the decision makers, allowing recognizing the interaction between all elements in the electricity system, which are fundamental for the long range planning. The illustration above shows how installing different values of wind power leads to the redefinition of the required capacity for each technology, and of the output among different generation.

The aim of this exercise was not to present an exhaustive description of all possible plans, but rather to drew attention to some examples showing the relevance of presenting other possible strategies to decision makers. The new proposed solutions ensure the required CO_2 maximum levels and present also a maximum 28% cost increase over the $R3$. However, they may become more interesting when other aspects, such as the external energy dependency or the need to balance coal and gas in the system, are considered.

2.5 Conclusions

This paper analyses the generation expansion planning problem in a mixed hydro-thermal-wind power system. For this, one optimization model for electricity planning was presented and adapted to the characteristics of the system under study. A deterministic programming model was proposed aiming to support the long-term strategic decision, and taking into account the need to reconcile economic and environmental objectives. Being deterministic, the model assumes perfect knowledge of the demand, legal and technical restrictions and costs over time. The proposed model can be used to assist in the strategic electricity planning process of systems strongly supported on hydro and thermal power and with expected wind power increase. The model usefulness was demonstrated for a case study but may be easily adapted to other cases with similar characteristics, allowing to design and analyze different policy options recognizing the interaction between the elements of the electricity system and the seasonality of the underlying renewable energy sources.

From the solution of the optimization model and assuming the described departing conditions, the results indicate that as the CO_2 objectives become more restrictive, in general, the least expensive way to comply is to firstly replace the coal by CCGT and by wind power production. Wind power contribution only increases significantly for highly environmentally constrained solutions. These results may be explained by the low capacity credit of wind and the required hydropower reserve schemes directly related with the total installed wind power. Also, these hydro schemes represent an important contribution to meet the RES constraint, allowing then to keep the installed wind power below the estimated potential.

The analysis of close to optimal solutions demonstrate how planning based on optimization models still remains an essential tool, when other objectives beyond the economic and cost are intended to be considered. It was possible to observe that imposing the installation of a fixed value of new wind power would lead to different scenarios that, although not being optimal Pareto solutions, may be interesting from the strategic decision makers' perspective. These solutions ensure the required CO_2 levels at a higher cost but contribute to the reduction of the external energy dependency of the country and to the increase of RES share in the electricity balance. This approach may be particularly useful to support multicriteria sustainable electricity planning decisions, based on the evaluation of minimum (or close to minimum) cost scenarios and taking into account other environmental and social objectives.

The proposed model assumed monthly load blocks to capture the wind and hydro seasonality. Also, the combination of wind and hydro pumping is expected to smooth the wind power variability and to increase the flexibility of the system (REN, 2013a). Nevertheless, the importance of designing long range planning models properly, accounting for short-term impacts of RES of variable output on thermal power operation performance, should not be overlooked, in an effort to find solutions of lower costs but not at an expense of higher CO_2 emissions.

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Chapter 3

Short-term electricity planning with increasing wind capacity

Paper published as Sérgio Pereira, Paula Ferreira, and A.I.F. Vaz. Short-term electricity planning with increase wind capacity. Energy, 69(0)12–22, 2014.

ABSTRACT

The variable electricity output of the renewable energy sources (RES) power plants, such as wind and hydropower, is an important challenge for the electricity system managers. This paper addresses the problem of an electricity system supported mainly on hydro, thermal and wind power plants. A binary mixed integer non-linear optimization model with hourly time step is described. The model is applied to a system close to the Portuguese electricity case assuming demand forecasts for the year 2020. The main objective of this paper was to analyze the impact that different levels of installed wind power can have in the operation of this electricity system, taking into account the hourly and intra-annual variation of the renewable resources, the demand projections and also the technical restrictions of thermal power plants. The results confirmed wind power as strategic technology to reduce both the marginal cost and CO_2 emissions. According to the simulations run, wind power will not replace hydropower but a decrease of thermal power production is foreseen as more wind power is added to the system. Gas power plants will be the most affected ones for large wind power scenarios, increasing part load operation and reducing the numbers of operating hours.

Keywords: Wind power, electricity planning, renewable energy sources, thermal power plants.

3.1 Introduction

Over the passed decades, electricity system generation has gone over a set of different changes. Different technologies start to arise and the importance of Renewable Energy Sources (RES) for electricity generation is now remarkable. RES technologies are usually characterized by zero CO_2 gas emissions, lower operation and maintenance costs but higher investment costs.

The promotion and use of RES for electricity generation is one of the most important greenhouse gas mitigation measures (Delarue et al., 2009). However, the increasing use of these technologies creates new challenges to the electricity power management. They are frequently characterized by production of variable output, are not subject to dispatch and can benefit from feed-in-tariffs. On the contrary, in most electricity systems, large thermal and hydropower plants compete in the market for dispatch.

The intra-annual seasonality and the variability of wind power output can be particularly challenging, significantly impacting the performance of thermal power plants operating in the same electricity system. According to Jonghe et al. (2012), large-scale wind power development affects short-term operation of the electricity system, as well as the optimal generation technology mix since wind increase significantly the variability of energy generation. The variability of wind power into the grid will enforce thermal generators ramping to compensate supplying disruptions or to operate at low load conditions. According Troy et al. (2010), increasing variability and unpredictability in the power system, due to wind curve characteristics, will frequently originate the increasing number of startups, ramping and periods of operation at low load levels. In line with this, Duque et al. (2011) support that, with the increase of wind power generation all over the world, the integration of wind power generation in electricity power systems needs to be carefully performed and requires new concepts in operation, control and management. In their study, a joint operation between a wind farm and a hydro-pump plant is addressed having into account the uncertainty of the wind power forecast.

Other concern that is usually related to RES technologies such as wind and hydro is the difficulty on forecasting their availability. Different studies have focused on this thematic. Wang et al. (2009) study the impact of wind power forecasting on the unit commitment problem and economical dispatch. A set of different scenarios to deal with wind uncertainty were considered, transforming the problem into a stochastic one. Despite the complexity usually associated to the stochastic problems that usually leads to better results, the authors concluded that a deterministic method combined with an increased reserve requirement can produce results that are comparable to the stochastic case. In Vardanyan and Amelin (2011) a survey of short-term hydropower planning with a large amount of wind power in the system is presented. In their study some conclusions were underlying. They have concluded that research when uncertainty is considered is not fully explored and when considered can significantly increase problem size, which may require more advanced solution algorithms and techniques to bring problem size down and make it solvable.

This work aims to contribute to the analysis of the impact of wind power in the operating performance of an electricity system combining thermal, hydro, and wind power plants. For that, an optimization model for short-term electricity planning will be presented and used to test different levels of installed wind power, evaluating the effect on cost and CO_2 emissions. The proposed model resources to hourly time steps, allowing to capture the hourly variation of the renewable resources and also to take into account the technical restrictions of the thermal power plants.

This paper is organized as follows. Section 3.2 will present an overview over the definition of unit commitment problem. A set of literature examples will be described to better understanding. In section 3.3 the proposed model formulation will be described. In Section 3.4 a realistic case study of an electricity system with thermal, hydro and wind power plants system is addressed, and the results of the model implementation are analyzed. Finally, conclusions are stated in Section 3.5.

3.2 Short-term planning: The Unit Commitment problem

It is well addressed in the literature that the principal aim of power planning, whether it is applied to long-term planning horizon or to short-term horizon, is to minimize the operation cost of the system allowing to fulfil a forecasted demand. Optimization models for short-term electricity power generation scheduling are therefore seen as useful and powerful tools to decision makers.

Short-term electrical power generation scheduling also known as unit commitment (UC) problem is essential for the planning and operation of power systems. The basic goal of the UC problem is to properly schedule the *on/off* states of all the units in the system. Further on, the optimal UC should meet the predicted load demand, plus the spinning reserve requirement at every time interval minimizing the total cost of production (Senjyu et al., 2003). Şima Uyar et al. (2011) describe the short-term electrical power generation scheduling as an optimization problem, in which optimal startup and shutdown schedules need to be determined over a given time horizon for a group of power generators under operational constraints. The objective remains the minimization of the power generation costs meeting the hourly forecasted power demands. Following this idea, Zhang et al. (2011) focused on the variations in operating costs caused by integration of an increasing amount of wind power in thermal generation systems. According to the simulation results the authors concluded that wind power brings considerable cost increase on thermal generation. Furthermore, when wind power is integrated in the grid, more flexible generation with higher cost are dispatched in peak load regulation, units starts and stop more often and more money is spent on ramping costs, increasing the average cost of the system.

Niknam et al. (2009) presented on their work a typical UC problem. A new formulation based on benders decomposition was proposed and the performance evaluated under three case studies for a typical system with 100 units. The first case study shows the effectiveness of the proposed algorithm without considering the ramp rate constraints while in the second case study, the ramp rate constraints were taken into account. The third case study considers no startup costs in the system. The numerical results obtained allowed the authors to confirm the efficiency of the study. Simoglou et al. (2010) addressed on their work the problem of the self-scheduling of a thermal electricity producer in day-ahead energy and reserves markets. Three different startup types are modeled, each one with different start-up costs, synchronization time, soak time, and predefined startup power output trajectories, all dependent on the unit's characteristics. The model was tested for a daily versus weekly scheduling of a fictional producer with five units using a typical load demand curve of the Greek Power System.

Despite the economic interest of these problems the environmental concern is also becoming increasingly relevant. Catalão et al. (2008) study focus on a multi-objective problem formulation with two objective functions, total fuel cost and total emissions. Also Chiang (2007) present a multi-objective problem for the economic emission dispatch of a hydrothermal power systems. On his work two objective functions were presented, one for the total cost and the other for the total emissions allowance. The results show the best cost, the best emission and the best compromise solutions. The pareto-optimal was also presented representing the trade-off between the cost and environmental objectives. Delarue et al. (2009) presented, in a case study for Belgium, a simulation tool that properly models wind power and its unpredictability and allows to determine the effects that wind power has on the cost of electricity generation and on CO_2 emissions.

Many other studies addressing the short-term electrical power generation scheduling are well documented in literature with emphasis on the changes that occur in the operation of the thermal units due to increase of wind penetration on system and on the the market prices (see for example Traber and Kemfert (2011) and Troy et al.

(2010)). In the next section, the proposed model formulation will be described, considering all technical constraints of thermal power units such as ramps, minimum up and downtime and start-up and shut down cost.

3.3 Model formulation

The formulation followed in this work for the unit commitment problem, in a system with high penetration of wind and hydropower, is described in detail in this section. The model assumes a set of different fossil fuel units mostly comprised of coal and gas. In what concern to hydropower units, the model assumes two different types such as: the large hydropower units with reservoir and the run–of–river units. Pumping units were also included in the model. Due to the increase complexity of the model no individual set for wind and hydropower units were considered. Instead, the model assumes all the individual wind power units as one, and the same will occur with hydropower technologies. By assuming wind and hydropower units as aggregated units the variability of the output of each independent unit is overlooked. This strategy allows to reduce the complexity of the model and is expected to not severely compromise the results, as no grid bottlenecks in the Portuguese system are considered in the model.

3.3.1 Objective function

The proposed model formulation takes into account the economic cost, originating one objective function to be considered. This objective function is set up by the sum of the variable costs of the electricity system. The variable costs, encompass the variable Operation and Management (O&M) costs, fuel and pumping cost, CO_2 emission allowance costs and shutdown and startup costs for each group. The objective function is measured in € and is defined by:

$$\sum_{t\in T}\sum_{j\in J}[C_{t,j}+Su_{t,j}+Sd_{t,j}]+\sum_{t\in T}[CVOM_{h_d}\times phd_t]+\sum_{t\in T}[CVOM_{h_r}\times phr_t]+ \\ \sum_{t\in T}[(Cp_p\times ppump_t)+(CVOM_p\times ppump_t)]+\sum_{t\in T}[(pwind_t\times CVOM_e)] \quad (3.3.1)$$

where T is the set of the time period (in hours) considered in the model, J is the set of all groups of thermal power plants included in the system, $C_{t,j}$ is the total cost of thermal power groups (€), $Su_{t,j}$ is the startup cost of thermal power groups (€), $Sd_{t,j}$ is the shutdown cost of thermal power groups (€), $CVOM_{h_d}$ is the O&M cost of hydropower plants with reservoir (€/MWh), phd_t is the power output of hydropower plant with reservoir in hour t

(MWh), $CVOM_{h_r}$ is the O&M cost of run–of–river power plants (€/MWh), phr_t is the power output of run–of–river power plant in hour t (MWh), Cp_p is the cost of pumping (€/MWh), $ppump_t$ is the power output of pumping power plant in hour t (MWh), $CVOM_p$ is the O&M cost of pumping power plant (€/MWh), $pwind_t$ is the power output of wind power plant in hour t (MWh) and $CVOM_e$ is the O&M cost of wind power plants(€/MWh).

The costs of thermal power groups considered in objective function above encompasses the fuel cost of each group, the O&M cost, the emissions allowance cost and the startup and shutdown costs. Those can be defined by equations (3.3.2), (3.3.3), (3.3.4), and (3.3.5).

$$C_{t,j} = \left[F_j + CVOM_j + (CO_{2_j} \times EC)\right] pt_j \tag{3.3.2}$$

$$Sd_{t,j} = CSd_j \times (v_{t-1,j} \times (1 - v_{t,j})) \tag{3.3.3}$$

$$Su_{t,j} = ColdS_j \left(v_{t,j} \times (1 - v_{t-1,j})\right) \times \prod_{n=1 \to N_j} 1 - v_{t-n,j} \tag{3.3.4}$$

$$Su_{t,j} = HotS_j \left(v_{t,j} \times (1 - v_{t-1,j})\right) \times \left(1 - \prod_{n=1 \to N_j} 1 - v_{t-n,j}\right) \tag{3.3.5}$$

where F_j is the fuel cost of group j (€/MWh), $CVOM_j$ is the O&M cost of thermal power group j (€/MWh), EC is the CO_2 emission allowance cost (€/ton), CO_{2_j} is the CO_2 emission factor of type j power group (ton/MWh), CSd_j is the shutdown cost of thermal power group j, $v_{t,j}$ is the binary variable that is 1 if thermal power group j is on in hour t or 0 if it is off, $ColdS_j$ is the cost of the cold startup of power group j (€), N_j is the time necessary for a cold startup (h) and $HotS_j$ is the cost of the hot startup of power group j (€).

3.3.2 Constraints

The set of adopted constraints for the unit commitment problem usually includes constraints derived from physical processes, demand requirements, capacity limitations, and legal/policy impositions. These constraints are equations that impose conditions to the model formulation, defining values of the decision variables that are feasible Hobbs (1995).

Demand Constraint

To ensure the reliability of the system, the production of all power plants should meet the total system load at each hour of planning period. Thus, the demand must be equal to the total power output from power plants plus the special regime producers power output minus pumping consumption. The mathematical formulation of this constraint is

$$\sum_{j \in J} pt_{t,j} + phd_{t,h_d} + phr_{t,h_r} + pwind_{t,e} - ppump_{p,j} + Psrp_t = D_t \quad \forall t \in T \tag{3.3.6}$$

where D_t is the demand in hour t of planning (MWh) and $Psrp_t$ is the generation output of all special regime producers (except large hydropower plants and wind power plants) including co-generation in each t hour of the respective planning period (MWh).

Thermal Power Capacity Constraints with Ramp Considerations

Power capacity constraints ensures that all power groups included in the model will not produce more than respective group capacity for each hour of the planning period. Indeed, the power output will be less or equal to the power group capacity. A minimum output of 35% of capacity for coal and gas thermal power groups is considered due to its technical characteristics. Furthermore, startup and shutdown ramp constraints were also considered to ensure a more reliable system representation. Mathematical formulation of these constraints is

$$\overline{p_{t,j}} \leq \overline{P_j} \left[v_{t,j} - (v_{t,j} \times (1 - v_{t+1,j})) \right] + (v_{t,j} \times (1 - v_{t+1,j})) \times Sdr_j \tag{3.3.7}$$

$$\overline{p_{t,j}} \leq pt_{t-1,j} + Ru_j \times v_{t-1,j} + Sur_j \times (v_{t,j} \times (1 - v_{t-1,j})) \tag{3.3.8}$$

$$\overline{p_{t,j}} \geq 0 \tag{3.3.9}$$

$$\overline{p_{t,j}} \geq pt_{t,j} \tag{3.3.10}$$

$$\underline{P_j} \times v_{t,j} \leq pt_{t,j} \tag{3.3.11}$$

$$pt_{t-1,j} - pt_{t,j} \leq Rd_j \times v_{t,j} + Sdr_j \times (v_{t-1,j} \times (1 - v_{t,j})) \tag{3.3.12}$$

$$pt_{t,j} \geq 0 \tag{3.3.13}$$

where $\overline{p_{j,t}}$ is the maximum power generation of group j in time t (MWh), $\overline{P_j}$ is the maximum capacity of thermal group j (MW), Sdr_j is the shutdown ramp limit of group j (MWh), Ru_j is the ramp up limit of group j (MWh), Sur_j is startup ramp limit of group j (MWh), $\underline{P_j}$ is the minimum capacity of thermal power group j (MW) and Rd_j is the ramp down limit of group j (MWh)(see Arroyo and Conejo (2004)).

Minimum up and down time of thermal power groups

Minimum Up and Down time constraints enforce the feasibility of system in terms of proper technical operation of units. Once a shutdown is verified the group must remain off for a certain period of time as well as if startup happens, the group must remain working over a certain time period. Equation (3.3.14) and (3.3.15) ensure then operation feasibility in terms of minimum up and minimum down time constraints, respectively.

$$\sum_{i \in i \leq UT_j} v_{t+i,j} \geq UT_j \times (v_{t,j} \times (1 - v_{t-1,j})) \tag{3.3.14}$$

$$\sum_{i \in i \leq DT_j} 1 - v_{t+i,j} \geq DT_j \times (1 - v_{t,j}) \times (v_{t-1,j}) \tag{3.3.15}$$

where UT_j is the minimum up time of thermal group j and DT_j is the minimum down time of thermal group j.

Large Hydro Constraints

For the large hydropower plants with reservoir, constraints regarding the expected storage and production capacity for each hour of planning period are considered in the model. The following equations relate the reservoir level for the hour t in terms of the previous reservoir level, inflows, and consumption. Two sets of constraints appear due to the need of consider an initial reserve for the first hour of the planning period.

$$reserve_t = Inflows_t + (\eta_p \times ppump_t) - phd_t + Ir \qquad t = 0 \tag{3.3.16}$$

$$reserve_t = Inflows_t + (\eta_p \times ppump_t) - phd_t + reserve_{t-1} \qquad \forall t \in T \setminus \{0\} \tag{3.3.17}$$

where $reserve_t$ is the reservoir level on hour t of the planning period, $Inflows_t$ is the hydro inflow on hour t of the planning period, Ir is the initial reserve of reservoir on hour 0 of planning period and η_p is the efficiency of pumping units.

Additional upper and lower bounds must be used to define maximum and minimum reservoir levels as well as the maximum power output of these units that must be less or equal to groups capacity. The following set of equations represent these constraints.

$$reserve_t \leq reserve_{max} \tag{3.3.18}$$

$$reserve_t \geq reserve_{min} \tag{3.3.19}$$

$$phd_{h_d,t} \leq \overline{P_{h_d}} \tag{3.3.20}$$

where $reserve_{max}$ and $reserve_{min}$ are the maximum and minimum reservoir level allowed, respectively and $\overline{P_{h_d}}$ is the maximum power capacity of hydropower unit with reservoir.

The next set of constraints makes the production of run-of-river power plants equal to the installed power, taking into consideration the availability of these units. This type of plants are characterized by its reduced storage capacity.

$$phr_t = \phi_{h_r,t} \times \overline{P_{h_r}} \tag{3.3.21}$$

where $\phi_{h_r,t}$ is the run–of–river units availability in hour t that is strongly season dependent.

Pumping Constraints

For the mathematical formulation of the operation of hydropower plants with pumping capacity, two reservoirs must be taken into account. The upper one storages water from inflows and from pumping itself, while the lower one storages water already used for electricity generation that later may be pumped again to the upper level. Again two set of constraints are necessary to model the initial pumping reserve for the first hour of planning period.

$$Preserve_t = phd_t - (\eta_p \times ppump_t) + PIr \qquad t = 0 \tag{3.3.22}$$

$$Preserve_t = phd_t - (\eta_p \times ppump_t) + Preserve_{t-1} \qquad \forall t \in T \setminus \{0\} \tag{3.3.23}$$

where $Preserve_t$ is the reserve of the pumping storage hydropower plant in hour t, PIr is the initial reserve of lower reservoir for instance t = 0.

The set of three next constraints representing the upper and lower bounds on the pumping reservoir and the maximum output production of pumping units, must also be included to ensure reliability of the system. These are represented by the following constraints.

$$Preserve_t \leq Preserve_{max} \tag{3.3.24}$$

$$Preserve_t \geq Preserve_{min} \tag{3.3.25}$$

$$ppump_{t,p} \leq \overline{P_p} \tag{3.3.26}$$

where $Preserve_{max}$ and $Preserve_{min}$ are, respectively, the maximum and minimum capacity of lower reservoir and $\overline{P_p}$ is the maximum capacity of pumping.

Wind constraints

This constraint ensures wind power generation capacity to be equal to the total installed power taking into account the wind availability. This constraint is set as an equality assuming that wind power is not subject to dispatch, making use of the feed-in tariffs and has priority access to the grid. Wind constraint is described by

$$pwind_{t,e} = \phi_{t,e} \times \overline{P_e} \tag{3.3.27}$$

where $\overline{P_e}$ is the maximum capacity of wind power units (MW) and $\phi_{t,e}$ is the wind availability in hour t.

Security constraints

Power units outages although not being frequent must be considered and prevented. These outages have different reasons for happen consisting essentially on the power units breakdown and stoppages for maintenance. Furthermore, suddenly increase of power consumption that may occur must be taken into considerations. Equation 3.3.28 represent this security constraint for each moment t.

$$\sum_{j \in J} \left(\overline{P_j} - pt_{t,j}\right) + \sum_{h_d \in H_d} \left(\overline{P_{h_d}} - phd_{t,h_d}\right) + \sum_{h_r \in H_r} \left(\overline{P_{h_r}} - phr_{t,h_r}\right) \geq D_t \times \alpha \tag{3.3.28}$$

where α is the parameter that will ensure the reliability of the system and usually represent 10%.

3.4 Model implementation and results analysis

3.4.1 Case study

The optimization model previously described was designed with the final aim of being used for a typical unit commitment problem in the analysis of a mixed hydro-wind-thermal power system. For this case study, a typical system encompassing all the electricity power generation technologies referred above was considered, highlighting the impacts that an increase wind power capacity have in the system. The particular case of the Portuguese electricity system was selected as representative of an example of this technology mix.

The Portuguese electricity system comprises essentially large thermal and hydropower plants in two different regimes: the ordinary regime production (ORP) encompasses thermal and large hydropower plants while the special regime production (SRP) encompasses renewable energy sources except large hydropower plants. The investment in new technologies, essentially wind power, is increasing due to environmental and social concerns along with the need to reduce the external energy dependence. According to WWEA (2011) in 2011, Portugal occupied the tenth world position in wind power capacity with 3960 MW installed, from which 260 MW were installed during the first half of 2011. This corresponds to 21% of total installed power of Portuguese national system and 17% of the total electricity production REN (2012). According to REN (2011), even despite of the 3.2% decrease in the Portuguese electricity consumption in 2011, an increasing trajectory of wind power is expected to keep on at least until 2022. In what concerns ORP, in 2011, a reduction of 27% of total hydropower production was observed totaling 10808 GWh, with a hydraulic productivity index (HPI)[1] of 0.92, against 14869 GWh of 2010 with a HPI of 1.31. On the contrary, thermal power groups production experience an increase of 12%, totaling 19435 GWh against the 17299 GWH of 2010. This variability is quite informative of the changes on production that power plants, highly dependent of climate conditions, can bring to the system.

Weather conditions and seasonality will influence the power output in each year and consequently, will have an impact on electricity system operation and on the thermal power units generation performance. Figure 3.1 and 3.2 demonstrate the variability of the wind and run–of–river hydro production for January and August[2]. As may be observed, the production of both wind and hydropower plants is much higher during winter (in January) than during summer (in August), due to the availability of the underlying resources. In fact in 2011, during the winter, RES production represented approximately 66% of the total electricity demand but during summer this share was only 24%. This demonstrates the need to analyze the short-term scheduling of the electricity system considering a large share of RES.

In order to reduce the complexity of the analysis, a closed system was assumed and the imports and exports were not accounted in the optimization process. This way, the analysis will look for optimal electricity plans to meet the internal demand at minimum generation cost.

3.4.2 Simulation process

According to Jonghe et al. (2012), although linear programming (LP) models have been successfully used because of their ability to model large problems, mixed integer programming models must be used when binary variables are associated with investment projects or non-convexities, such as minimum run levels and minimum up – and downtimes.

[1] Ratio between the hydropower production during a time period and the hydropower production that would be expected for the same period under average hydro conditions.

[2] Availability used as a proxy of the variability of the resource measured as power output/ maximum capacity.

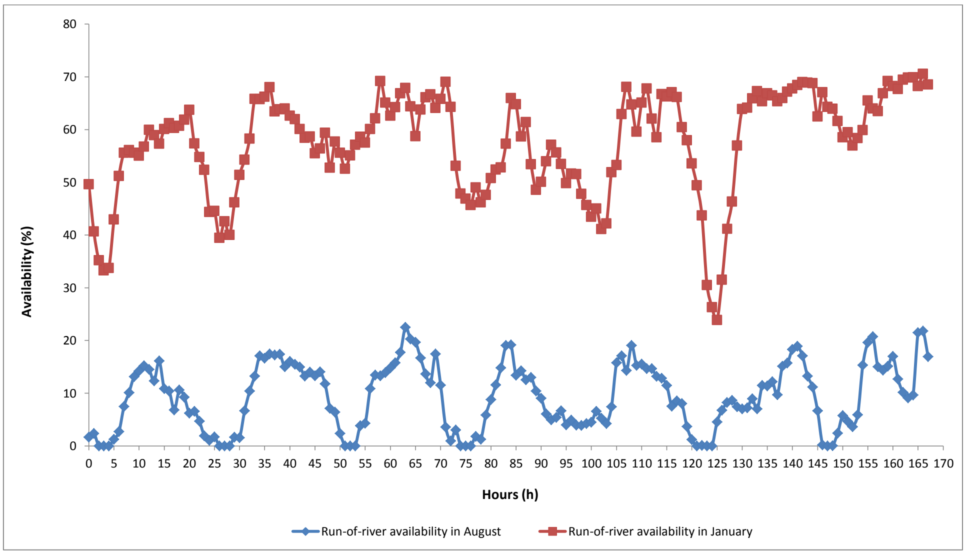

Figure 3.1: Hourly production of run–of–river power units in January and August 2011 weeks [Own elaboration from REN data].

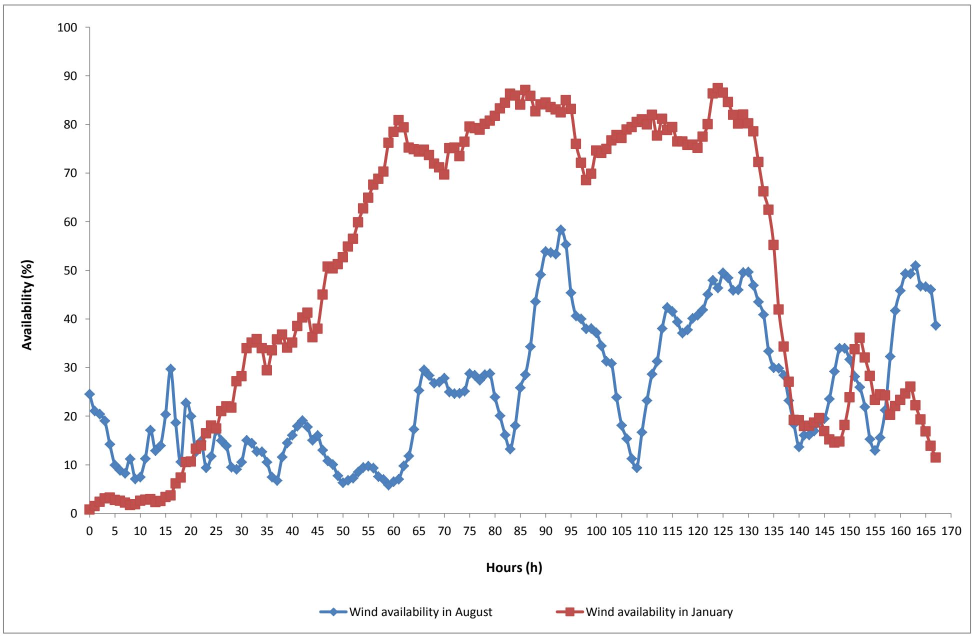

Figure 3.2: Hourly production of wind power units in January and August 2011 weeks [Own elaboration from REN data].

The previous described model is applied to the Portuguese case with a time horizon of one week. A total of 31 different thermal power units, mostly comprising coal and gas, were considered, corresponding to the Portuguese system in 2011. A single-objective problem described in equations (3.3.1)– (3.3.28) assumes a hourly time step, allowing to get an more accurate representation of all technical characteristics of power units, resulting in a mix integer nonlinear optimization problem (MINLP) with 16633 continuing variables, 5208 integer variables, 48889 equation constraints, 579261 non-linearities and 183592 nonzeros modeled in GAMS code (GAMS, 2011). The AlphaECP solver was selected to obtain the numerical results reported herein. Other optimization solvers were tested, but were unable to provide a satisfactory answer, either in time or final objective function value. The numerical results were obtained in a Microsoft Windows operating system using a 2.3GHz Pentium i5 computer with 4GB of memory.

Besides the installed wind power and the different fossil fuel units the model assumes two different types of hydropower technologies, the large hydropower units with reservoir and the run–of–river units. Hydro pumping units were also included in the model. The simulation was conducted assuming five different scenarios, each one representing five levels of wind capacity going from the base scenario with 4080 MW until an maximum increase of 50%, and demand forecasts for the year 2020. Both Table 3.1 and Table 3.2 describe the case study in terms of installed power and scenarios used. In the case described on Table 3.2, scenarios were created having into account the possible increase of the wind power capacity.

The behavior of an electricity system comprising high penetration of renewables can be strongly influenced by the climatic conditions of the different seasons of the year. Table 3.3 presents the average values of hydro and wind availability and the demand for each season since 2009 for the Portuguese power system. Analyzing this table is possible to conclude that the demand tends to be higher in the winter. It is also during this season that both hydro and wind availability are higher. On the contrary, it is on the summer that both hydro and wind power availability are lower. Moreover, the electricity demand in summer is close to the demand in Autumn and higher than the demand in Spring, which due to the lower hydro availability can create additional difficulties in the scheduling of the power system.

Due to the complexity of the model, this work uses as parameters the data of 4 typical weeks, corresponding each one to a typical season of the year. The objective is to minimize the total costs of the system, and to analyze the behavior of all thermal and hydropower units over all four representative weeks of the seasons for all scenarios presented in Table 3.2. The predicted wind and hydropower output were obtained from the hourly availability factor, which allowed to take into account the uncertainty and variability of wind and hydropower.

Table 3.1: Installed power system (Source: REN website).

	Technology	Number of power groups	Installed Power per technology (MW)
Thermal Power	Coal	8	1820
	Gas	15	4033
	Fuel	8	1145
Total	-	31	6998
Hydropower	Run-of-rivers	-	2583
	Large hydropower units	-	2649.8
Total	-	-	5232.3
Wind Power	-	-	4080
Pumping	-	-	1053.3

Table 3.2: Case study scenarios.

	Wind power (MW)
Base scenario	4080
+20%	4896
+30%	5304
+40%	5712
+50%	6120

Table 3.3: Seasonal characteristics of the Portuguese electricity system 2009–2011 (Source: Own elaboration using REN data).

	2011			2010			2009		
	Demand (MW)	Hydro avail.	Wind avail.	Demand (MW)	Hydro avail.	Wind avail.	Demand (MW)	Hydro avail.	Wind avail.
Winter (week 1)	6349.4	51%	31%	6515.2	61%	37%	6136.4	39%	28%
Spring (week 2)	5496.9	33%	22%	5536.1	47%	26%	5293.3	17%	21%
Summer (week 3)	5575.4	11%	23%	5830.3	18%	18%	5522.0	10%	20%
Autumn (week 4)	5684.4	24%	29%	5979.4	23%	31%	5837.6	17%	34%
Average/year	5776.5	30%	26%	5965.3	37%	28%	5697.3	21%	26%

3.4.3 Numerical results

The results obtained considering all scenarios are presented in Table 3.4. Analysing both Table 3.4 and Figure 3.3, it is possible to observe that for an increasing level of wind power generation, both the average cost and average CO_2 emissions tend to decrease. Comparing the base scenario with the scenario corresponding to an increase of 50% of wind power, it is possible to observe a reduction of 38%, 22%, 11% and 15% on the estimated cost of the system for a typical week in winter, spring, summer and autumn respectively. The costs reduction experienced in winter and spring weeks are more significant due to the weather conditions, more favorable to wind and to hydropower production, in these seasons. Clearly, the same happens when considering the production cost per MWh. For example, for the winter week a reduction from 14.8 €/MWh to 9.1 €/MWh have occurred between the base scenario and the wind +50% scenario. This reduction can be explained by the increase of electricity generation provided by wind power, characterized by no fuel costs and lower costs of operation and maintenance when comparing with traditional fossil fuel generation units. Another consequence of the increase of electricity generation provided by wind power is the reduction of CO_2 emissions. In addition to the non fuel costs and lower costs of operation and maintenance associated to wind power, these are also free of CO_2 emissions. An increase of wind production will then result in a reduction of the CO_2 emissions. Table 3.4 shows this reduction trend.

The behavior of the different technologies can be seen in figures 3.4 – 3.7. Observing both Figure 3.4 and

Figure 3.5 the reduction verified in the production provided from thermal power units is evident. This reduction is even more notorious for the CCGT power units, when comparing with coal power units, due to the technical characteristics of the both technologies. While coal units work as base load units, CCGT units are more flexible, being able to be online for a shorter time period and even fastest then coal power units. This means that CCGT units are used mostly during peak and close to peak hours, as can be seen in Figure 3.5 for example during the period between hours 6 and 27 of the planning period. During this period wind power registed lower generation values, promptly compensated by CCGT units. On the other hand, observing Figure 3.6 and Figure 3.7 it is possible to verify the lower electricity generation provided by wind and hydropower units, resulting from the lower availability of wind and hydro resources during the summer. This increases significantly the total cost of the system, even considering lower demand comparatively with the other seasons. As can be seen in both figures, coal and CCGT units will need to compensate renewable resources shortage to meet the demand imposing higher fuel and operation and maintenance costs.

Besides the coal, CCGT and fuel power units, the large hydropower units have an important role in the scheduling process. During seasons with higher hydro inflows and together with wind power, hydropower units contribute to reduce the cost of electricity generation through the reduction of the electricity provided by thermal power sources. Comparing the results of the winter and summer simulations presented in figures 3.5 and 3.7, the importance of the availability of RES resources and in particular of hydro becames evident. During summer hydropower contributed to 4.03% of the total output against 32.56% during the winter. As for wind, its contribution was 21.23% in the summer and increased to 34.96% in the winter. The shortage of hydro and wind resources is compensated by thermal power plants, contributing with 59.78% of the power production during the summer and only 17.54% during the winter. On the other hand hydropower units are flexible and so, together with CCGT power units are capable to suppress curtailment of wind power generation. Figures 3.6 and 3.7 demonstrate the importance of hydropower even during the summer, with large dams output compensating moments with high demand and low wind. This is can be observed for example during 55 – 65 hours in Figure 3.6 and 105 – 115 hours in Figure 3.7.

The variability of the electricity generation is well evidenced in all figures 3.4 – 3.7. Figures 3.8, and Figure 3.9 represent the load factor[3] and the utilization factor[4] of thermal power units when facing increasing levels of wind power in the system. Analayzing Figure 3.8, is possible to verify that during the summer and autumn the thermal units load factor is higher. This coincide with the lower availability of renewable resources. Coal power plants work mainly as

[3]Measure of the electricity produced at power plant compared to the maximum possible output in a time period.

[4]Measure of the working hours of a power plant compared to the maximum number of hours possible.

Table 3.4: Optimal objective functions solutions.

	Cost (€)	Marginal Cost (€/MWh)	CO_2 Emissions (ton/MWh)	Startups
		Base Scenario		
Week 1 (Winter)	19.486.812,22	14.8	0.175	129
Week 2 (Spring)	23.101.719,29	18.8	0.262	99
Week 3 (Summer)	34.658.326,21	31.6	0.379	52
Week 4 (Autumn)	29.592.443,86	26.9	0.343	60
		20% increase		
Week 1 (Winter)	15.980.853,11	12.1	0.161	116
Week 2 (Spring)	20.814.419,08	16.9	0.246	95
Week 3 (Summer)	33.154.141,98	30.2	0.369	62
Week 4 (Autumn)	27.712.873,14	25.2	0.327	56
		30% increase		
Week 1 (Winter)	15.310.537,48	11.6	0.144	118
Week 2 (Spring)	19.617.704,96	15.9	0.235	76
Week 3 (Summer)	32.885.106,64	29.9	0.367	105
Week 4 (Autumn)	27.051.093,74	24.6	0.321	97
		40% increase		
Week 1 (Winter)	13.578.053,12	10.3	0.133	83
Week 2 (Spring)	19.677.475,79	15.9	0.229	125
Week 3 (Summer)	31.970.882,98	29.1	0.360	105
Week 4 (Autumn)	27.310.160,46	24.9	0.325	109
		50% increase		
Week 1 (Winter)	12.001.397,79	9.1	0.119	54
Week 2 (Spring)	18.013.913,39	14.6	0.211	107
Week 3 (Summer)	30.980.476,08	28.2	0.350	75
Week 4 (Autumn)	25.023.238,29	22.8	0.304	67

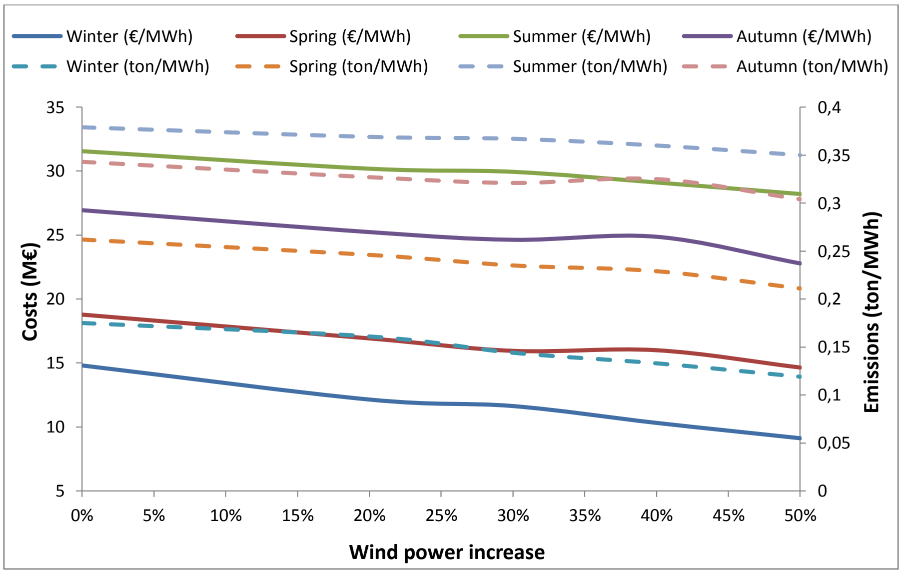

Figure 3.3: Cost and CO_2 results for different wind power scenarios

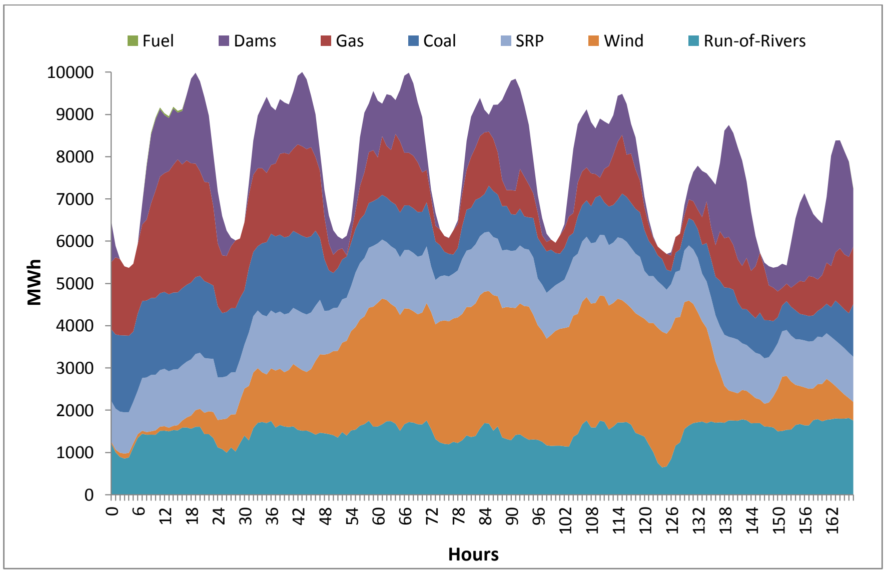

Figure 3.4: Power production for base scenario in a Winter week

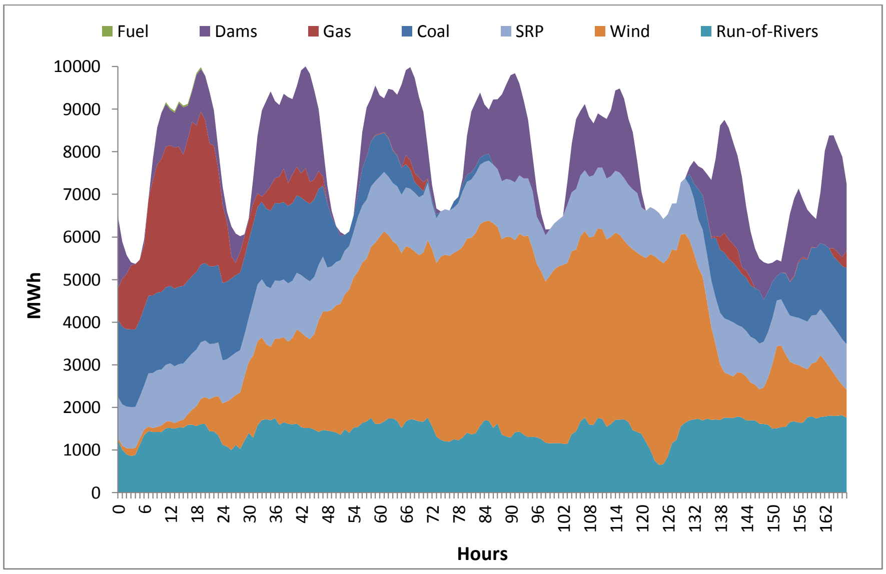

Figure 3.5: Power production for 50% wind power increase in a Winter week

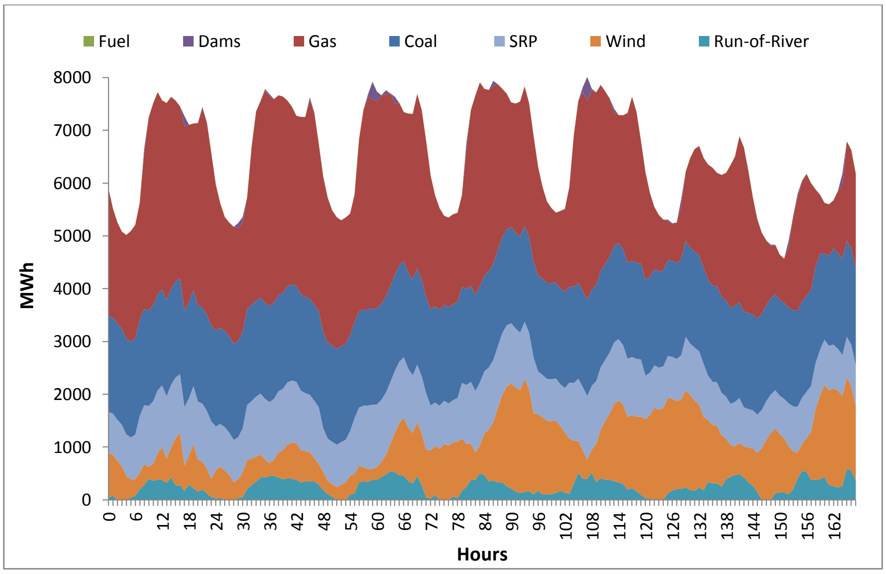

Figure 3.6: Power production for base scenario in a summer week

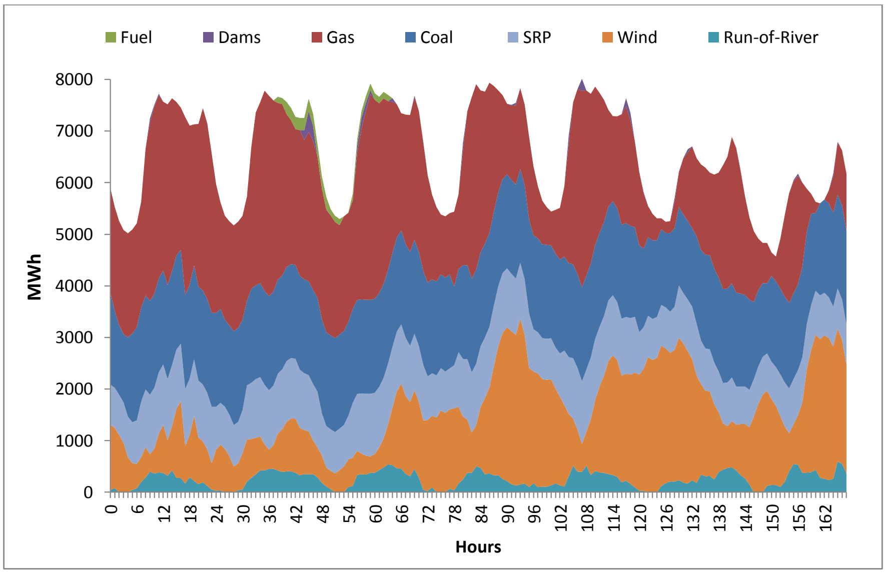

Figure 3.7: Power production for 50% wind power increase in a summer week

base load and their load factor tend to be high for all the scenarios, even reaching full load in base scenario and scenario +20% during the summer. In general, the load factor tends to decrease, even if slightly in some cases, as the wind capacity increases. The utilization factor tends to be higher than load factor in seasons with more renewable resources which means that each thermal unit tends to be working more hours but at lower load factor.

All these findings can be confirmed more easily through the figures 3.10 – 3.13. The relation between load factor and utilization factor is clearly influenced by the increase of wind power and also by the different characteristics of the seasons of the year. Comparing both figures 3.10 and 3.11 with figures 3.12 and 3.13 the higher load and utilization factors of the thermal units during seasons with lower values of wind electricity generation is evident. According to the results, the increase of wind power will impact the utilization and load factors of all thermal power plants. However, and as expected CCGT will experience the strongest reduction on their output due to their technical characteristics but also due to their highest fuel costs. The results also show that an increase of wind power generation will not replace the hydropower generation. This can be seen by the slight increase of the hydropower load factor as the wind capacity increases. Notwithstanding, the impact on coal is also evident specially during the winter season. As for fueloil, although the figures show some changes the importance on the overall system is reduced, as fueloil power output represents only between 0% and 2.97% of the total production for the assumed scenarios.

Other aspect that strongly influences the behavior of the power units and by this way the cost of the system, is

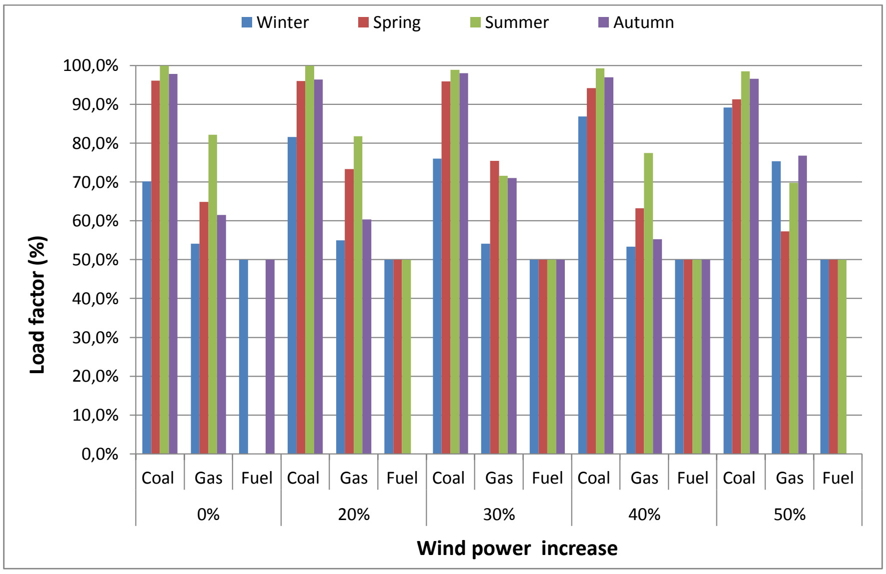

Figure 3.8: Thermal power units load factor

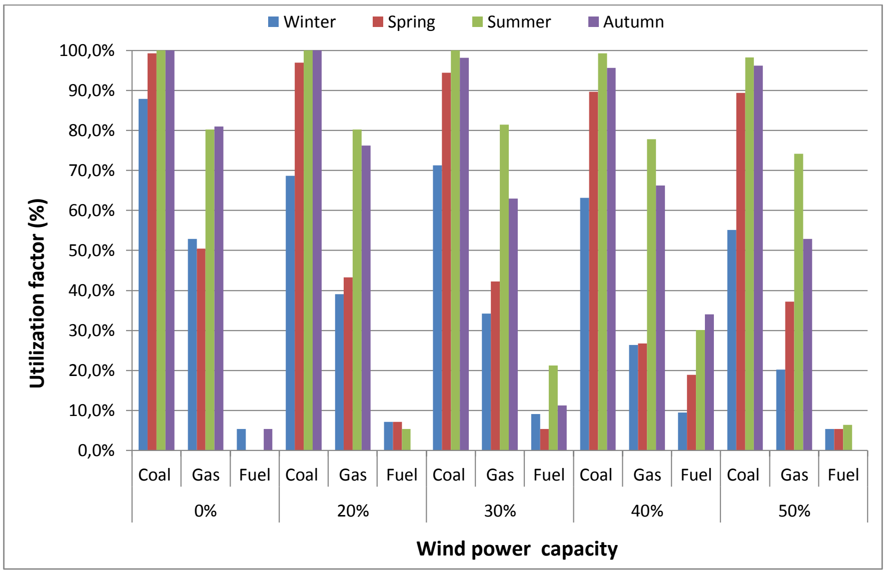

Figure 3.9: Thermal power units utilization factor

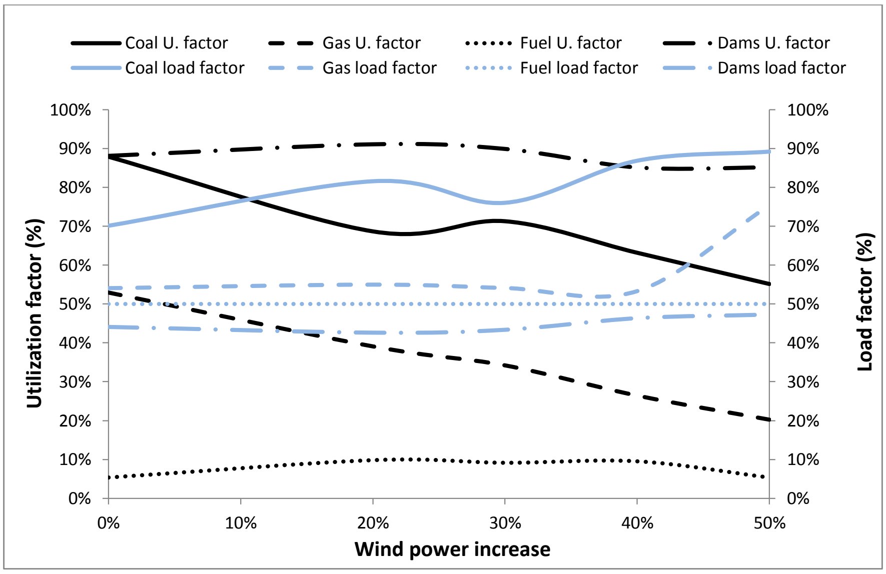

Figure 3.10: Load factor VS utilization factor for a Winter week

the number of startups and shutdowns of thermal power plants. Figures 3.14 – 3.17 show that no linear trend can be derived. In fact, although the number of startups seem to be higher in large wind power scenarios, during the winter period for example the startups of the gas power plants reduce with increasing wind power levels. During the summer, the number of startups of CCGT is more sensitive to the increase of wind power, which can be related to the low of hydro availability, reducing the dam possibilities of compensating wind variability.

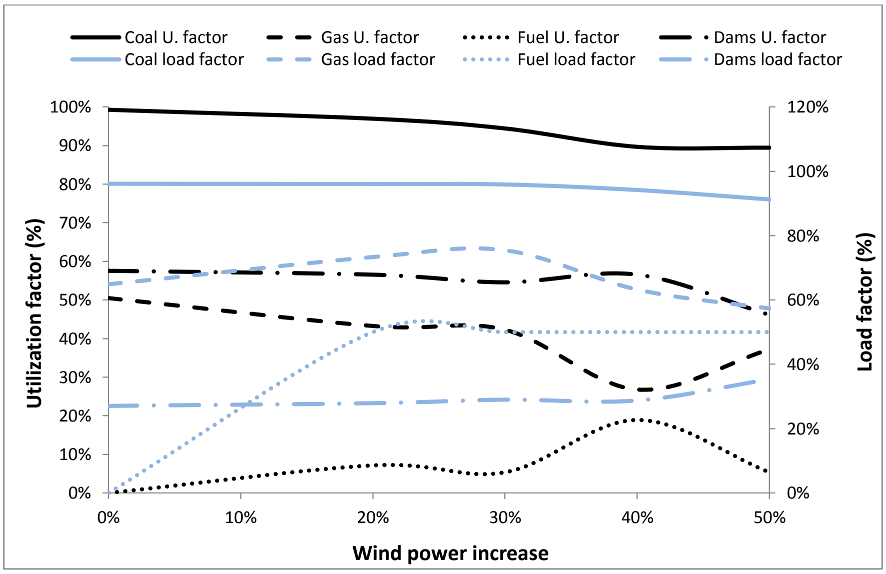

Figure 3.11: Load factor VS utilization factor for a Spring week

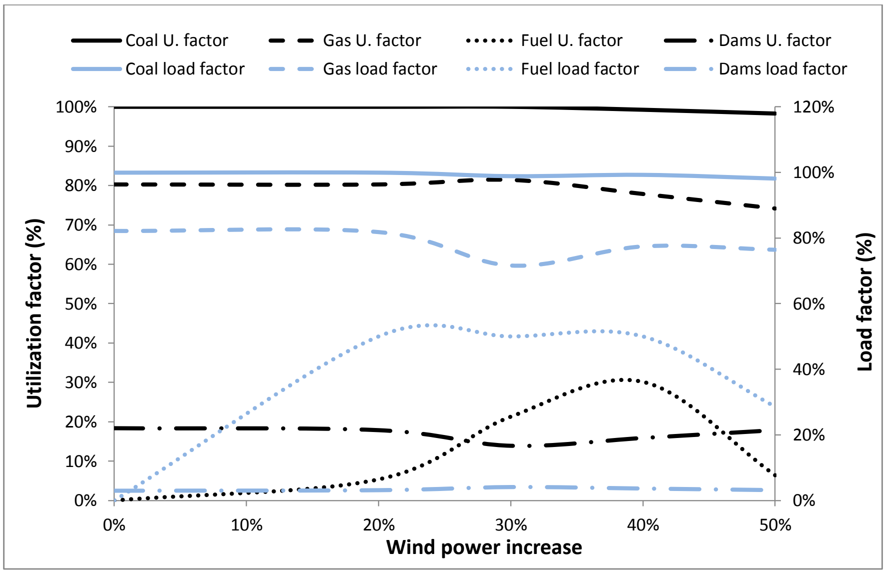

Figure 3.12: Load factor VS utilization factor for a Summer week

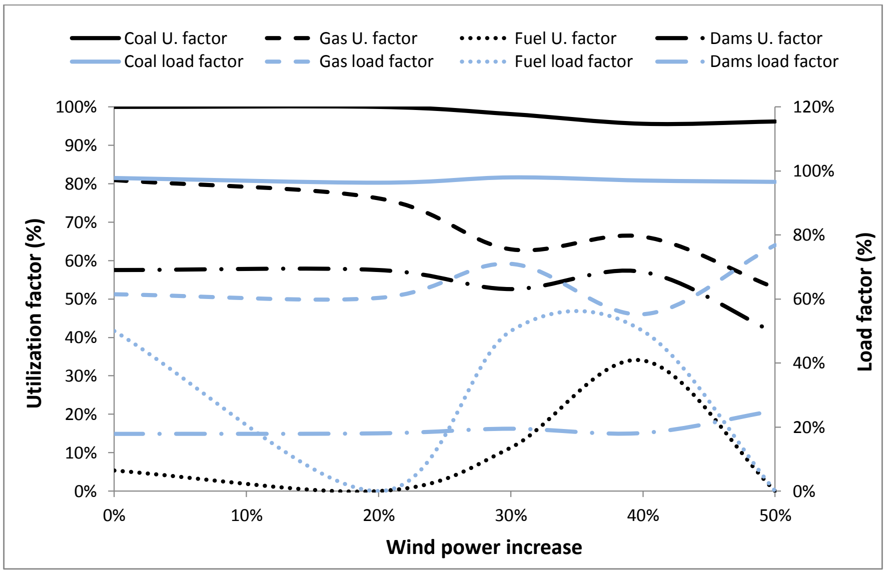

Figure 3.13: Load factor VS utilization factor for a Autumn week

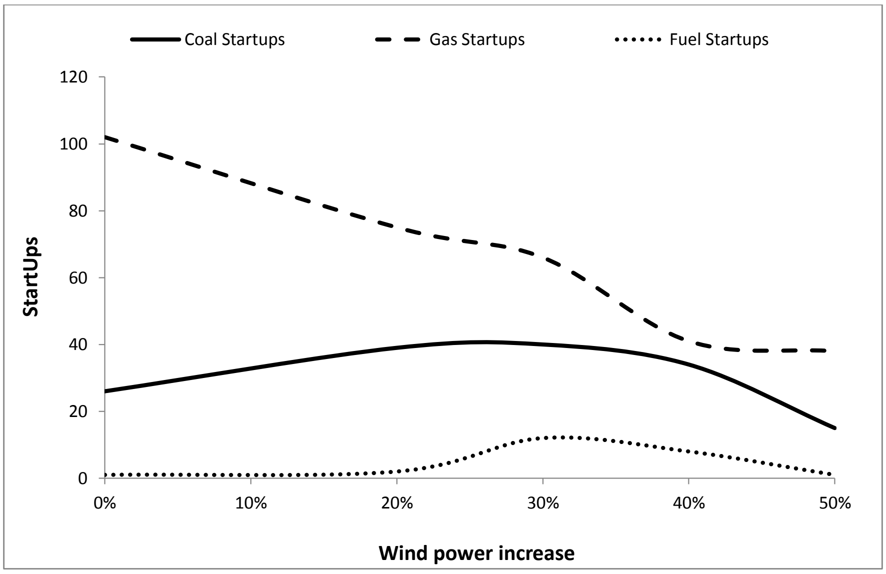

Figure 3.14: Startups for a Winter week

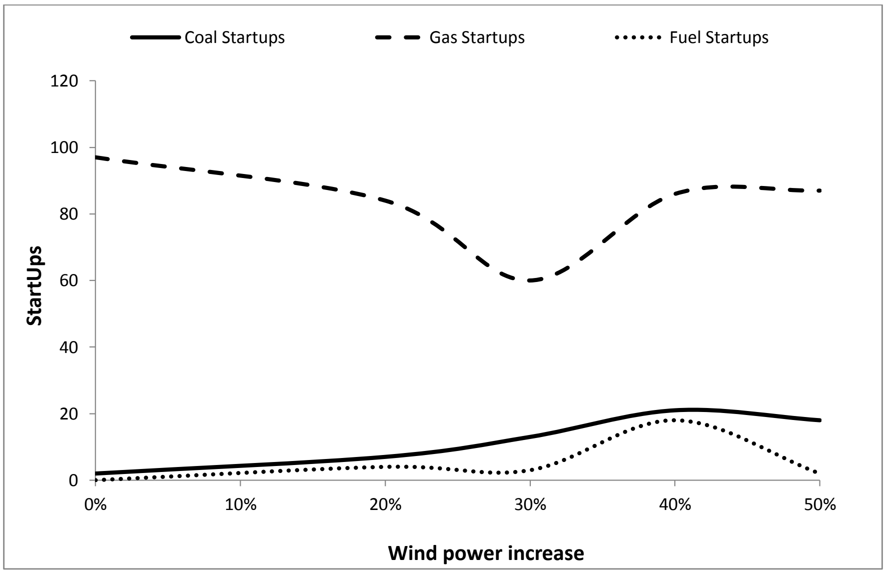

Figure 3.15: Startups for a Spring week

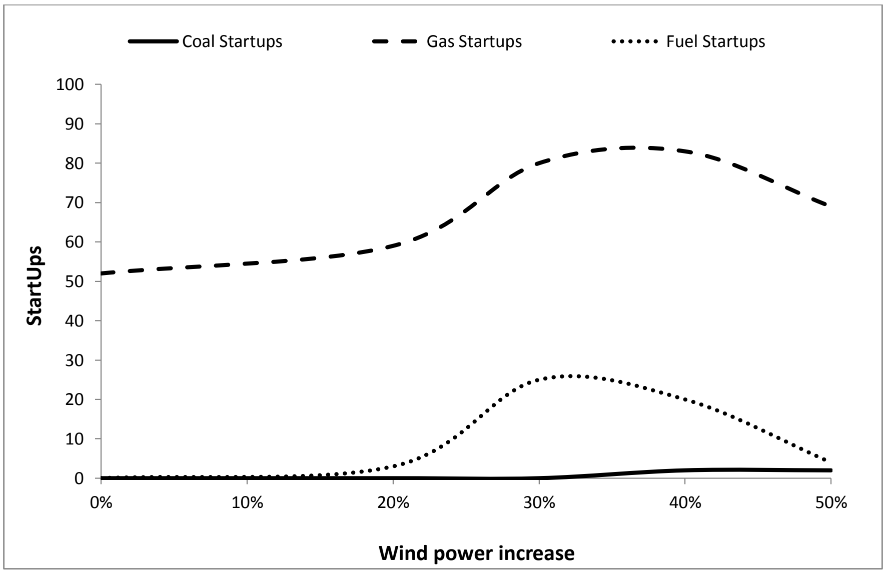

Figure 3.16: Startups for a Summer week

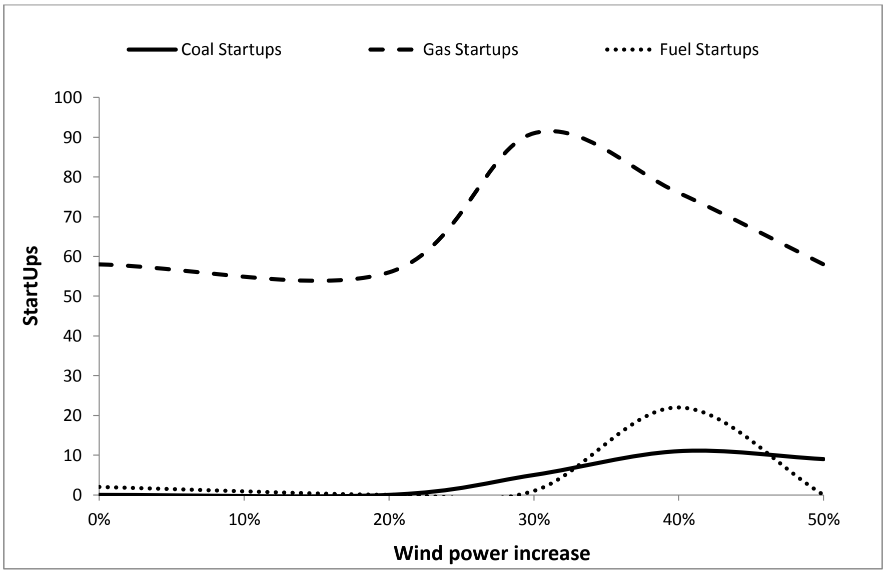

Figure 3.17: Startups for a Autumn week

3.5 Conclusions

This paper analyzes the short-term electricity power generation scheduling also known as unit commitment problem. For this, one optimization model was presented and adapted to the characteristics of the system under study aiming to analyse the impact of increasing wind power scenarios in a systems containing hydro, wind and thermal power plants.

From the solution of the optimization model and assuming the described departing conditions, the results indicate that as the wind power capacity increase the overall marginal cost of the system tend to decrease. These results are explained by the lower RES costs of operation and maintenance comparatively to traditional fossil fuel power plants. The same way, being the wind power free of CO_2 emissions the results also confirms the reduction of the CO_2 emissions, as wind capacity increases.

Another important aspect is the fact that for all the scenarios, the lower production costs and CO_2 emissions are always achieved during the winter period. Although this season presents the higher electricity demand it is also the one with higher wind and hydro availability. On the contrary, during the summer period both the wind and hydro availability are lower, leading to higher thermal power production and causing an increase on the marginal costs and CO_2 emissions of the system. This demonstrates the impact and importance of analyzing the seasonal behavior of resources and consumption during electricity power planning.

The results also shows that coal power units will work as base load units while gas and hydropower units, being more flexible, will frequently be required to work as peak load units. As such, the increase of wind capacity is expected to have a major impact on the gas units. This is reflected in the increase number of startups of these power units caused by the variability of the electricity generation provided by wind power. In addition to the increase number of startups, a decrease on the production of electricity provided by CCGT is observed for increasing wind power scenarios. It is also important to note that the changes on the load factor of the fueloil units is practically negligible for this study as fuel power output represents at most 3% of the total electricity production. The results also show that an increase of the wind power generation will not replace the hydropower generation. This can be seen by the slight increase of the hydropower load factor as the wind capacity increases.

Analysing all results becomes evident the complexity faced by all grid managers. The results comprove the fact of the increasing variability and unpredictability of wind power generation, frequently originate that thermal power plants will experience an increasing number of startups, ramping and periods of operation at low load levels. Thus, no linear trend can be derived. In fact, although the number of startups seems to be higher for large wind power scenarios, during the winter period for example the startups of the gas power plants reduce with increasing wind power levels. During the summer, the number of startups of CCGT is more sensitive to the increase of wind power, which can be related to the low of hydro availability, reducing the dam possibilities of compensating wind variability. Regardless of these technical impacts, the main results of the analysis put in evidence the importance of wind power as strategic technology to reduce both the marginal cost and CO_2 emissions of this electricity system.

Acknowledgements

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Chapter 4

A simplified optimization model to short-term electricity planning

Paper submitted for publishing in international journal in March 2015 as Sérgio Pereira, Paula Ferreira, and A.I.F. Vaz. A simplified optimization model to short-term electricity planning.

ABSTRACT

Short-term optimization models, usually applied to traditional problems like unit commitment (UC) and economic dispatch problem, are essential tools for the planning and operation of power systems. However, the large number of variables and restrictions, necessary for a good and more accurate representation of any electricity system, require high computational resources, frequently resulting in high computation times. This study proposes a simplified approach of a model for the electricity planning of power plants allocation based on the available resources. The proposed model resources to quadratic penalty functions to replace the unit *on/off* binary variables frequently included in the UC problem. The approach is then supported on a non-linear optimization model able to solve this electricity planning problem in shorter computation times, with solutions close to the ones obtained with more complex models. The model is fully described and tested under different scenarios of an electricity system comprising thermal, wind, and hydropower plants. The results were compared to the ones obtained with a more complex model, analysing the main differences obtained for cost, CO_2 emissions, and thermal power groups commitment. The major advantage of the

simplified model comes from the computational time needed for state-of-the-art optimization solvers to provide an optimal solution, comparatively to mixed integer models.

Keywords: Electricity planning, short-term planning, renewable energy sources, thermal power plants.

Nomenclature

SETS	
T - Set of the time period (h)	*J* - Set of all thermal power groups
C - Set of all coal power plants	*G* - Set of all gas power plants
PARAMETERS	
$CVOM_{h_d}$ - Variable O&M cost of hydropower plants (€/MWh)	$CVOM_{h_r}$ - Variable O&M cost of run–of–river power plants (€/MWh)
$CVOM_p$ - Variable O&M cost of pumping power plants (€/MWh)	$CVOM_e$ - Variable O&M cost of wind power plants (€/MWh)
$CVOM_j$ - Variable O&M cost of thermal power group j (€/MWh)	C_{p_p} - Pumping cost (€/MWh)
F_j - Fuel cost (€/MWh)	EC - CO_2 emissions allowance costs (€/ton)
CO_{2_j} - CO_2 emissions factor of thermal power plant j (ton/MWh)	CSd_j - Shutdown cost of thermal power plant j (€)
$ColdS_j$ - Cost of cold startup of thermal power plant j (€)	$HotS_j$ - Cost of hot startup of thermal power plant j (€)
N_j - Time necessary for a cold startup in hours	
VARIABLES	
$C_{t,j}$ - Total cost of thermal power group j in hour t (€)	$Su_{t,j}$ - Startup cost of thermal power group j in hour t (€)
$Sd_{t,j}$ - Shutdown cost of thermal power group j in hour t (€)	phd_t - Power output of large hydropower plants in hour t (MWh)
phr_t - Power output of run–of–river power plants in hour t (MWh)	$ppump_t$ - Power output of pumping power plants in hour t (MWh)
$pwind_t$ - Power output of wind power plants in hour t (MWh)	$pt_{t,j}$ - Power output of thermal power plants j in hour t (MWh)
$v_{t,j}$ - Binary variable that is 1 if thermal power group j is on in hour t or 0 if it is off	$L_c(t)$ - Load factor of coal power groups (MW)
$L_g(t)$ - Load factor of gas power groups (MW)	a_c, b_c, c_c - Coefficients of coal quadratic curves
a_g, b_g, c_g - Coefficients of gas quadratic curves	$\overline{P_j}$ - Maximum capacity of thermal power plant j

4.1 Introduction

The increase of Renewable Energy Sources (RES) technologies characterized by its variable output, and frequently with priority access to the grid, can contribute to the increasing number of startups and shutdowns of thermal power plants and also enforcing ramping, due to possible disruptions or low load conditions operation (Troy et al., 2010; Jonghe et al., 2012). Modern electricity power generation systems own a high level of complexity, usually with a high set of thermal power plants combined with RES power plants and giving rise to a large number of technical constraints. Short-term optimization models, usually applied to traditional problems like UC and economic dispatch problem, arise as essential tools for the planning and operation of power systems. These tools can also be used to support energy decision making, allowing to test the expected outcomes of different electricity scenarios. However, due to the complexity associated to these problems, the translation of these problems in a computational language becomes a hard task. The large number of variables and restrictions, necessary for a good and more accurate representation of any electricity system turns the code complex and highly computational resource consuming.

The basic goal of the UC problem is to properly schedule the *on/off* states of all the generation power plants in the system. Further on, the optimal UC should meet the predicted load demand, plus the spinning reserve requirement at every time interval minimizing the total cost of production (Senjyu et al., 2003; Şima Uyar et al., 2011). According to Hobbs (1995), traditional UC and economic dispatch problems usually requires short-term periods of time. Time periods ranging from one to ten minutes or eight hours to one week for economic dispatch and UC problem respectively are example of time periods addressed in short-term optimization models.

UC plays an important role in the economic operation of the entire power system. In fact, a diversity of technics have been applied over the time to solve this problem. Technics such as, Bender's decomposition (Bertsimas et al., 2013), differential evolution (Mandal and Chakraborty, 2009), evolutionary algorithms (Georgopoulou and Giannakoglou, 2009), genetic algorithms (Dhanalakshmi et al., 2013), Lagrangian Relaxation (Frangioni et al., 2011), MILP optimization (Viana and Pedroso, 2013), particle swarm optimization (Jeong et al., 2010), simulated annealing (Saraiva et al., 2011) and stochastic optimization (Wang et al., 2013) are examples of mathematical approaches used to solve the UC problem. For example in Mandal and Chakraborty (2009), both economic and environmental concerns are considered for the problem of short-term scheduling, resulting in a multi-objective problem. To solve the problem an algorithm based on differential evolution is used and a price penalty factor is considered, transforming the problem into a single objective one. Also Georgopoulou and Giannakoglou (2009) present in their work a multi-objective short-term scheduling problem with stochastic demand data. However, in this particular case, a evolutionary algorithm method is considered. Other interesting work is for example the work presented in Viana and Pedroso (2013). Instead of presenting a typical large-scale MINLP to solve the UC problem, the authors present a simplified approach by the mean of a piecewise linear approximations, transforming the MINLP into a MILP.

The, objective of this work is twofold. Firstly, a simplified model for the UC problem is presented with the final goal of reducing the complexity traditionally present in these models and computational tools, resulting in less computation time to get an optimal solution. A nonlinear quadratic problem (NLQP) resorting to penalty functions to replace the unit *on/off* binary variables is therefore proposed in this paper. Secondly, a comparison between the presented model and a more complex one, detailed in Pereira et al. (2014) is presented. The comparison will be made in terms of the obtained costs, CO_2 emissions, thermal power plants commitment, and the total simulation time needed. For this, an analysis of a case study representative of a electricity system comprising thermal, wind, and hydropower plants is addressed. The selected case study corresponds to an electricity system close to the Portuguese one. Foreseen load demand and SRP (Special Regime Producers, representing renewable and cogeneration non subject to dispatch) production data for the year 2020 is considered. Simulations were conducted assuming three different scenarios, each one representing different levels of wind capacity. The seasonality of both hydro and wind power recourses is considered, as the models are compared under four typical weeks, each one representing a season of the year, with hourly time step (0–167h).

This paper is organized as follows. First, section 4.2 will present an overview of the proposed simplified model. All simplifications in relation to the more detailed and complex model proposed in Pereira et al. (2014) will be presented and analyzed. In section 4.3 a comparison between the results obtained with both models will be described. For this comparison, the simplified model will be applied to the specific case study of a thermal, hydro, and wind power electricity system described in Pereira et al. (2014), analysing in particular the model usefulness to test different wind power scenarios aiming to support energy decision making. Finally, conclusions are stated in the last section, section 4.4.

4.2 Short-term electricity planning: a simplified approach

According to Jonghe et al. (2012), although linear programming (LP) models have been successfully used because of their ability to model large electricity generation mix problems, mixed integer programming models must be used when binary variables are associated with investment projects or non-convexities, such as minimum run levels and minimum up and downtimes of thermal power plants. However, when dealing with problems of high dimension, the use of binary variables can lead to difficulties in terms of computational effort and consequently in obtaining an optimal solution in reasonable time. In order to reduce these difficulties, some changes to the model previously proposed in Pereira et al. (2014) are introduced. These changes encompasses the removal of the binary variables and the consideration of quadratic curves for fuel and emissions costs, aiming to penalize both the operation of thermal power plants at reduced load factors and the startups. It is expected that this penalty can avoid the use of binary variables associated to minimum up and down time of thermal power groups, ramp considerations, and startup and shutdown restrictions in Pereira et al. (2014), without severally compromising the quality of the results.

Usually, the fuel cost per unit of output (specific fuels costs, €/MWh), in any given time interval, is given as a function of the generator power output or load factor and is represented by a quadratic function. In the specific case of this work, the curves considered for the representation of the fuel and CO_2 emissions costs are a function of each generator load factor. Both the assumed gas and coal fuel curves can be seen in Figure 4.1.

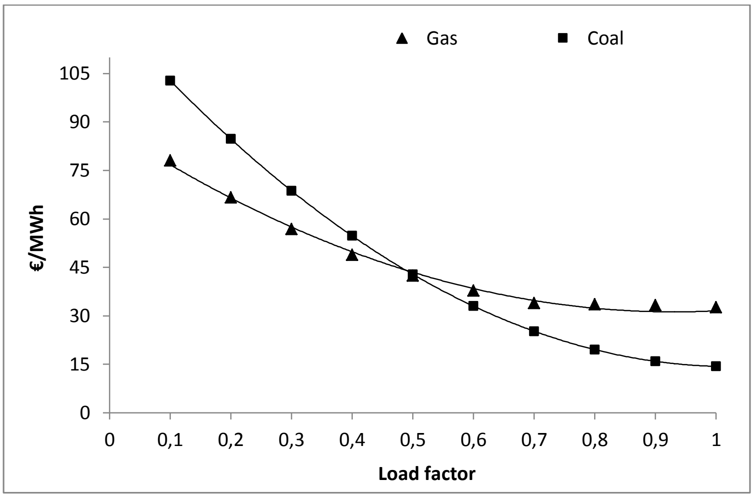


Figure 4.1: Coal and gas fuel cost curves.

The same assumptions were considered for the CO_2 emissions cost curves (specific emission factors, t/MWh). Figure 4.2 shows precisely the behavior of both coal and gas emissions cost curves as the generator load factor increase.

The previously proposed model presented in Pereira et al. (2014) is represented by a single objective function, corresponding to the minimization of the operational costs. This objective function is set up by the sum of the variable costs of the electricity system, encompassing the variable operation and maintenance (O&M) costs, fuel and pumping costs (hydro), CO_2 emission allowance costs, and shutdown and startup costs for each thermal group. Moreover, for both fuel costs and CO_2 emissions of thermal power groups, average values were assumed. The objective function is measured in € and was defined in equation (4.2.1), further defined in equations (4.2.2 - 4.2.5).

$$\sum_{t \in T} \sum_{j \in J} [C_{t,j} + Su_{t,j} + Sd_{t,j}] + \sum_{t \in T} [(CVOM_{h_d} \times phd_t) + (CVOM_{h_r} \times phr_t) +$$

$$(Cp_p \times ppump_t) + (CVOM_p \times ppump_t) + (pwind_t \times CVOM_e)] \quad (4.2.1)$$

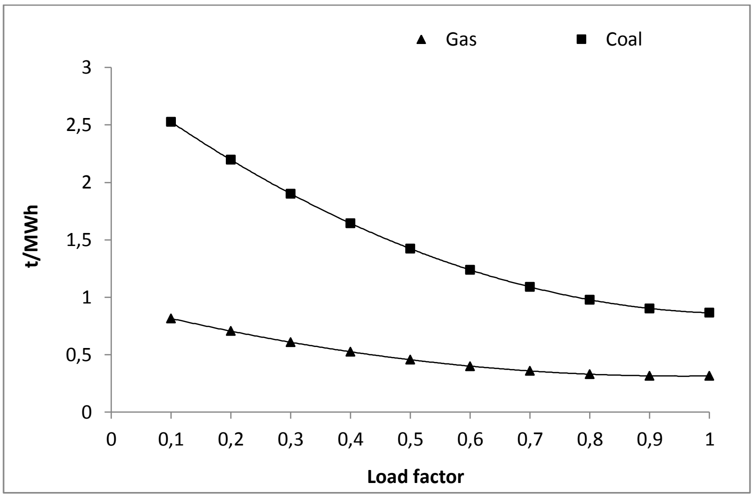


Figure 4.2: Coal and gas CO_2 emissions curves.

with,

$$C_{t,j} = \left[F_j + CVOM_j + (CO_{2_j} \times EC)\right] pt_{t,j} \tag{4.2.2}$$

$$Sd_{t,j} = CSd_j \times (v_{t-1,j} \times (1 - v_{t,j})) \tag{4.2.3}$$

$$Su_{t,j} = ColdS_j \left(v_{t,j} \times (1 - v_{t-1,j})\right) \times \prod_{n=1 \to N_j} 1 - v_{t-n,j} \tag{4.2.4}$$

$$Su_{t,j} = HotS_j \left(v_{t,j} \times (1 - v_{t-1,j})\right) \times \left(1 - \prod_{n=1 \to N_j} 1 - v_{t-n,j}\right) \tag{4.2.5}$$

In what concerns to the proposed model simplification, the original objective function described in equation (4.2.1) and equations (4.2.2 - 4.2.5), were replaced by a single new objective function described in equation (4.2.6). The main differences resulting from this change are therefore evident an encompasses the inclusion of the quadratic penalty functions and consequently the removal of binary variables.

$$\sum_{t \in T} \sum_{g \in G} \left[a_g (L_g(t))^2 + b_g(L_g(t)) + c_g\right] \times pt_{t,g} + \sum_{t \in T} \sum_{c \in C} \left[a_c (L_c(t))^2 + b_c(L_c(t)) + c_c\right] \times pt_{t,c} +$$

$$\sum_{t \in T} \sum_{g \in G} \left[a_g (L_g(t))^2 + b_g(L_g(t)) + c_g\right] \times EC \times pt_{t,g} + \sum_{t \in T} \sum_{c \in C} \left[a_c (L_c(t))^2 + b_c(L_c(t)) + c_c\right] \times$$

$$EC \times pt_{t,c} + \sum_{t \in T} \sum_{j \in J} [CVOM_j \times pt_{t,j}] + \sum_{t \in T} [CVOM_{h_d} \times phd_t] +$$

$$\sum_{t \in T} [CVOM_{h_r} \times phr_t] + \sum_{t \in T} [(Cp_p \times ppump_t) + (CVOM_p \times ppump_t)] +$$

$$\sum_{t \in T} [(pwind_t \times CVOM_e)] \quad \text{(4.2.6)}$$

Aside from changes in the objective function, other assumptions were taken into account to the simplification of the model. The minimum up and downtime constraints, presented in Pereira et al. (2014) were not considered in the simplified approach. The absence of these two constraints is assumed to be compensated by the quadratic function for fuel consumption and CO_2 emissions, penalizing a large number of startups and with this keeping the up and down times in a reasonably limit. Observing both figures 4.1 and 4.2, it is possible to verify that for lower values of load factor, costs, and CO_2 emissions tend to be higher. Usually low load factor values are registered during startup and shutdown periods or periods of high RES power output. In this last case, thermal power plants must decrease their power output with negative impacts on their efficiency. Under these conditions specific cost and CO_2 emissions of these plants may tend to increase. The inclusion of quadratic functions in the optimization model is expected to penalize both low load factor operation and frequent startup/showdown operations. Thermal power plant will then tend to operate at high load factor values, increasing its efficiency, reducing costs, and also the number of startups and shutdowns which should result in longer operating periods.

The last change comparatively to Pereira et al. (2014) is related to the ramping constraints. According to Simoglou et al. (2010, pg. 1967), ramps "*restrict the capability of a thermal unit to increase/decrease its output over any two successive time periods that the unit is either in the dispatchable phase, or involved in a startup or shut-down procedure*". Pereira et al. (2014) model, resorted once more to the use of binary variables to deal with the ramps constraints. For a simplification propose, the solution adopted in order to minimize the loss of exactitude was the assumption of a maximum variation of production, 30%, between two consecutive periods of time.

These assumptions result in equations (4.2.7) and (4.2.8) for ramp up and ramp down respectively.

$$pt_{t,j} - pt_{t-1,j} \leq 0.30 \times \overline{P_j} \tag{4.2.7}$$

$$pt_{t-1,j} - pt_{t,j} \leq 0.30 \times \overline{P_j} \tag{4.2.8}$$

4.3 Analysis of the results

The proposed model described in section 4.2 was coded in GAMS (2011). MINOS solver, that is interfaced with GAMS, was selected to obtain the numerical results reported herein. In this section a comparative analysis between Pereira et al. (2014) short-term model and the proposed simplified model will be discussed. This comparative analysis will be focused mainly on costs, CO_2 emissions, and number of startups and the total simulation time needed for both models. A case study representing a system with high reliance on wind, hydro and thermal power is used to proceed with the comparison. Four typically weeks were considered, as described in Pereira et al. (2014): week 1 corresponding to a winter week, week 2 representing a spring week, week 3 representing a summer week, and week 4 representing an autumn week. For each week, hourly time step (0–167h) was considered, describing the typical data characteristics of the season, more properly, demand profiles and wind and hydro availability. Also, different wind scenarios are considered departing from the base scenario corresponding to a total installed wind capacity of 4080 MW and assuming a 20% and 50% increase over this initial value. The simplification process results in a deterministic nonlinear quadratic optimization problem (NLQP) instead of the mixed integer nonlinear optimization problem (MINLP) in Pereira et al. (2014).

The results obtained by running both models are described in Table 4.2. Table 4.3 represents the relative difference between the models for cost, CO_2 emissions, and number of startups. In a general way, and as shown in both figures 4.3a and 4.3b, the main difference when comparing both models is related with the higher load factor of both coal and CCGT power groups for simplified model, resulting in an increase, even that slight, of global thermal generation. This is particularly evident for CCGT for the base case scenario. As for the utilization factor, described in figures 4.4a and 4.4b, the simplified model seems to converge to solutions relying less in the utilization of coal power plants. This means that the simplified model tend to be characterized by the search for solutions ensuring that

Table 4.1: Installed power system (Source: REN website).

	Technology	Number of power groups	Installed Power per technology (MW)
	Coal	8	1820
Thermal Power	Gas	15	4033
Total	-	23	5853
Hydropower	Run-of-rivers	-	2583
	Large hydropower plants	-	58423
Total	-	-	84256
Wind Power	-	-	4080
Pumping	-	-	1053

thermal power plants will be operating at high load factor levels even if they operate during a smaller number of hours. This can be explained by the use of quadratic characteristics curves for thermal power plants, penalizing the operation at low load factors.

The differences obtained between both models on costs and CO_2 emissions are mainly justified by the relative use of coal and natural gas and the higher or lower number of startups. Although the simplified model does not specifically include startup costs as model parameters, the use of quadratic curves penalize these startups. In fact, equation (4.2.7) restricts the capability of a thermal power plants to increase its output over any two successive time periods, meaning the starting up will impose lower load factors and consequently higher costs.

For example, for the 50% wind scenario, week 1 (winter) the simplified model converges to a solution presenting a higher load factor for coal but with lower utilization ratio. As for gas, although the load factor is lower its utilization ratio is considerable higher than the one obtained for the extended model. This increase on CCGT combined with the increase on the number of startups will result in a slight increase on the marginal cost but also on the reduction of the CO_2 emissions. This reduction on coal power output and increase on CCGT output is evident on figures 4.5a and 4.5b, where it is also possible to see the increase on the number of startups for CCGT. On the opposite for week 3 (summer) the solution of the simplified model is characterized by lower marginal cost, lower number of startups and lower emissions of CO_2, comparatively to the extended model. In this case, the lower costs seem to come both from

Table 4.2: Optimal objective functions solutions.

	Pereira et al. (2014) model			Simplified model		
	Marginal Cost (€/MWh)	CO_2 Emissions (ton/MWh)	Number of Startups	Marginal Cost (€/MWh)	CO_2 Emissions (ton/MWh)	Number of Startups
Base Scenario						
Week 1	14.8	0.175	129	13.8	0.178	102
Week 2	18.8	0.262	99	18.2	0.251	74
Week 3	31.6	0.379	52	28.2	0.382	37
Week 4	26.9	0.343	60	24.1	0.347	111
20% increase						
Week 1	12.1	0.161	116	11,8	0,163	167
Week 2	16.9	0.246	95	16,9	0,232	138
Week 3	30.2	0.369	62	26,8	0,369	64
Week 4	25.2	0.327	56	23,1	0,333	138
50% increase						
Week 1	9.1	0.119	54	9,3	0,103	137
Week 2	14.6	0.211	107	15,3	0,178	107
Week 3	28.2	0.350	75	25,7	0,341	53
Week 4	22.8	0.304	67	21,4	0,299	119

the lower number of startups, from the higher load factors obtained for the CCGT and from the higher dams power output as shown in figures 4.6a and 4.6b.

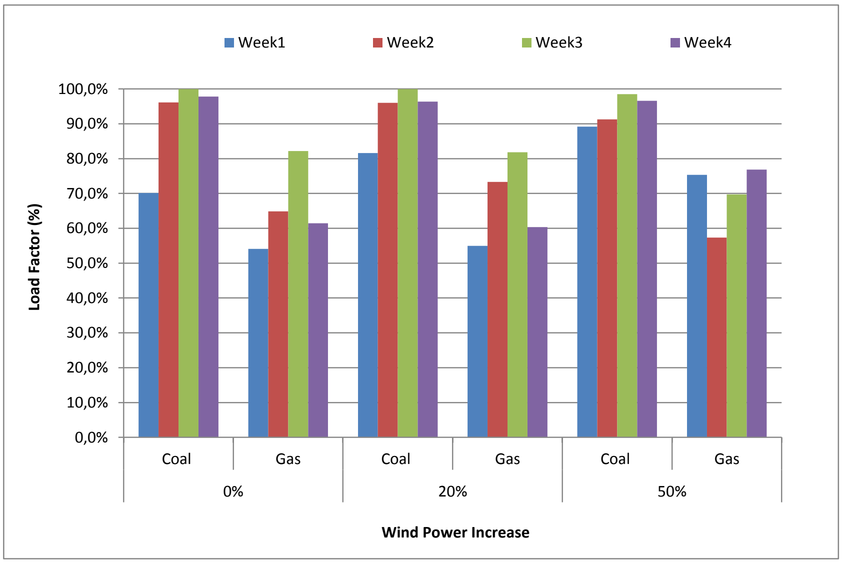
The same goes for the base case scenario described in figures 4.7 and 4.8, where the lower number of startups obtained for the simplified model both for weeks 1 and 3 have a clear influence on the resulting lower costs. In addition, for week 3, dams power output is higher for the simplified model, which also leads to lower marginal costs.

Despite the differences observed in the system behavior between both models, the maximum difference of the obtained cost values was 12.7% and in most of the simulations this difference was less than 10%. On the other hand the computational time to obtain a optimal solution was reduced significantly. While the original Pereira et al.

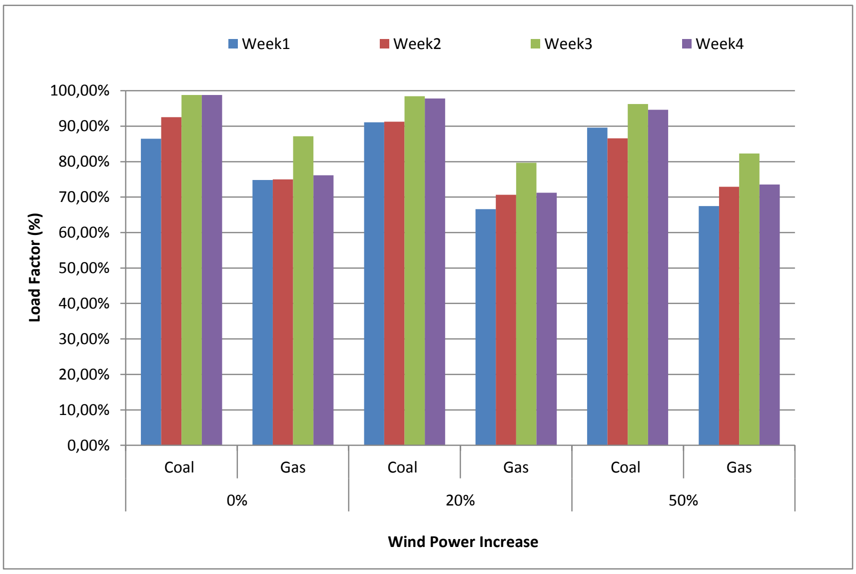
Table 4.3: Summary of models comparison for different wind power scenarios.

	Δ Marginal Cost	Δ CO_2 Emissions	Δ Startups
		Base Scenario	
Week 1	-7.2%	1.7%	-26.5%
Week 2	-3.3%	-4.4%	-33.8%
Week 3	-12.1%	0.8%	-40.5%
Week 4	-11.6%	1.2%	45.9%
		20% wind power increase	
Week 1	-2.5%	1.2%	30.5%
Week 2	0%	-6.0%	31.2%
Week 3	-12.7%	0%	3.1%
Week 4	-9.1%	1.8%	59.4%
		50% wind power	
Week 1	2.2%	-15.5%	60.6%
Week 2	4.6%	-18.5%	0%
Week 3	-9.7%	-2.6%	-41.5%
Week 4	-6.5%	-1.7%	43.7%

(2014) short-term model required in average 72 hours to obtain an optimal solution (4 weeks simulation with hourly time step each one), the simplified model was able to give a solution in approximately 2 minutes. This significant reduction in time allows the users to perform more detailed analysis of the system with the possible increasing in the number of scenarios under consideration. Thus, the simplified approach may be used with significant benefits mainly in what concerns to the computational time effort. This also means that the simplified model is clearly more suitable for supporting timely decision making although the results of the extended model reflect more reliable and realistic assumptions for the electricity operational planning.

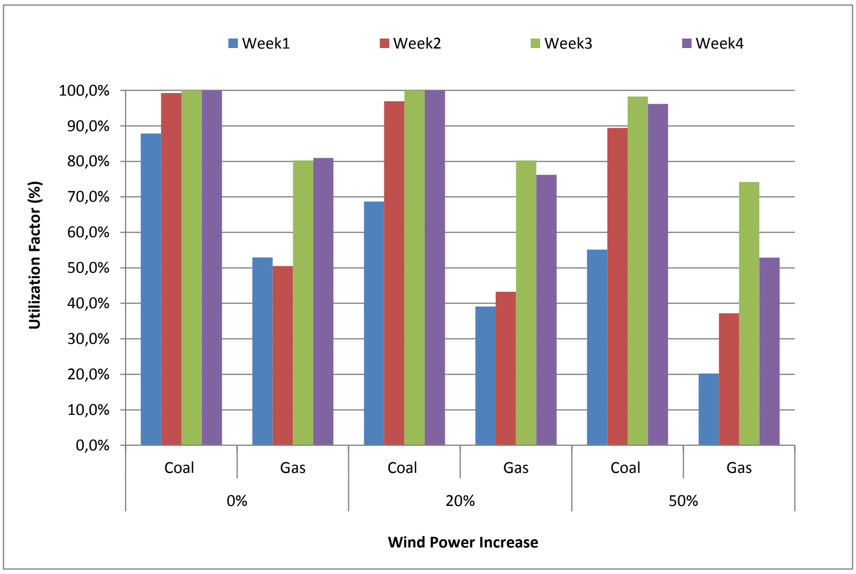


(a) Pereira et al. (2014) model

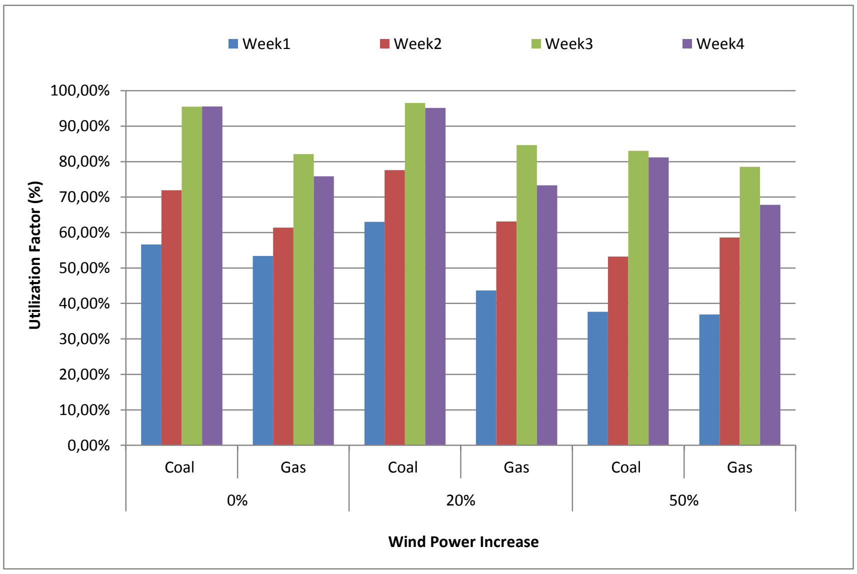


(b) Simplified model

Figure 4.3: Load Factor.

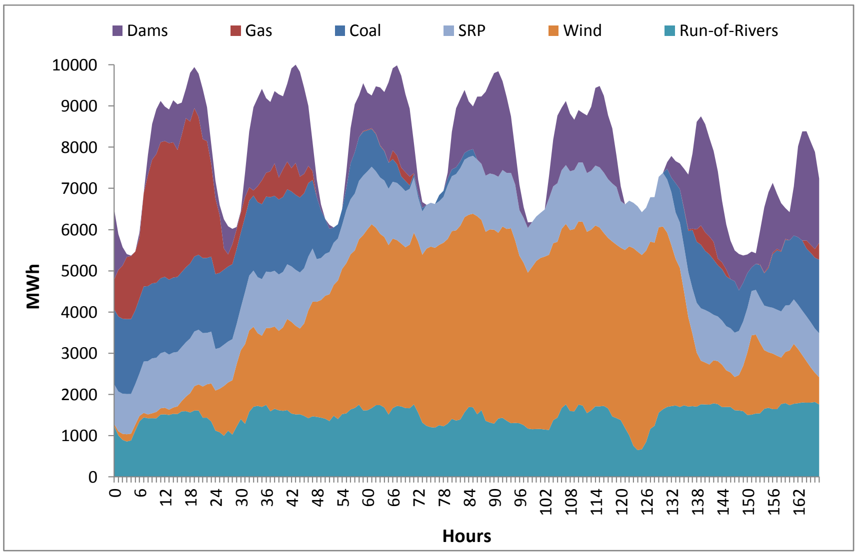


(a) Pereira et al. (2014) model

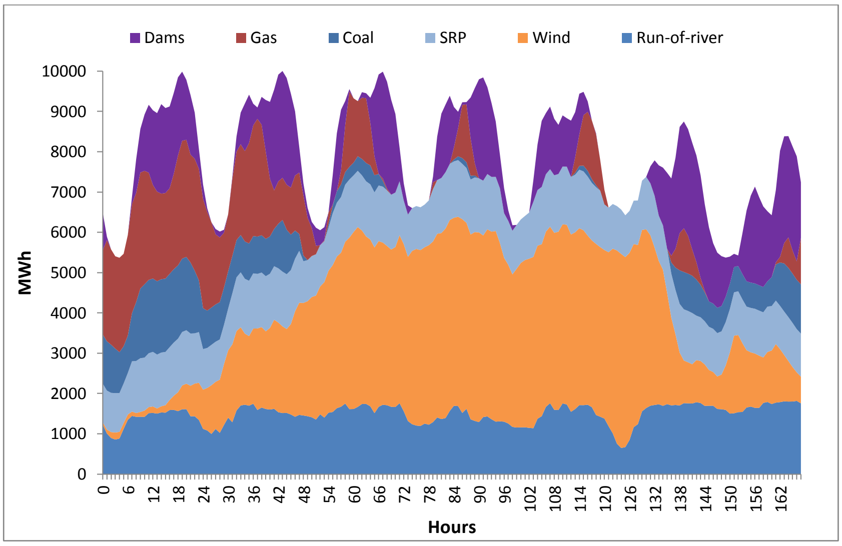


(b) Simplified model

Figure 4.4: Utilization Factor.

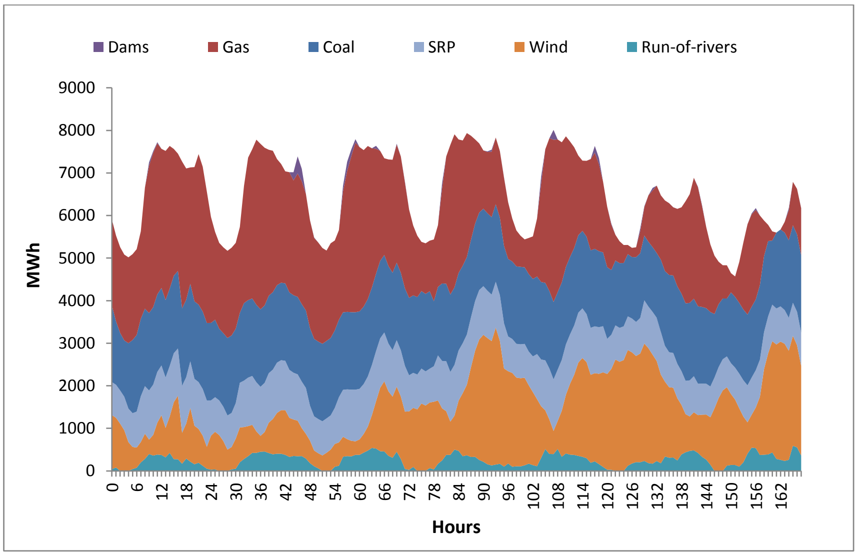


(a) Power production for 50% wind power increase in a Winter week (Pereira et al. (2014) model)

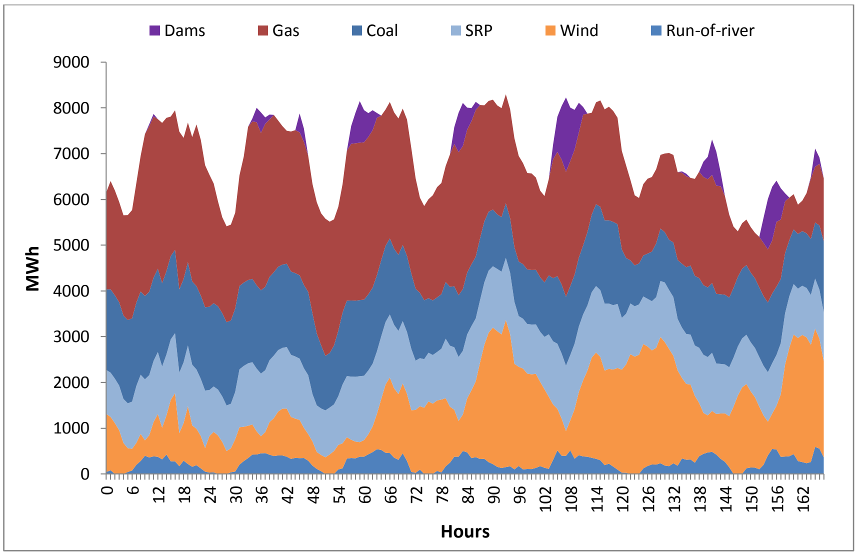


(b) Power production for 50% wind power increase in a Winter week (Simplified model)

Figure 4.5: Winter week with 50% wind power increase simulation results.

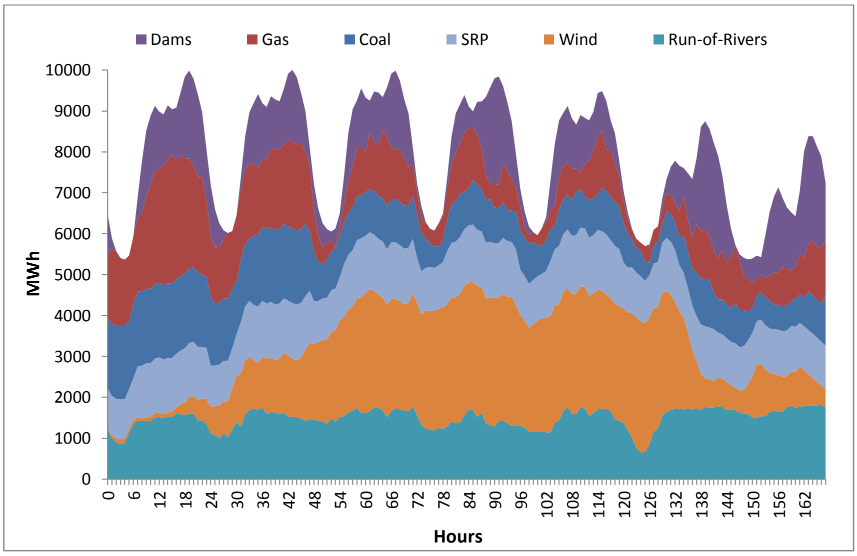


(a) Power production for 50% wind power increase in a Summer (Pereira et al. (2014) model)

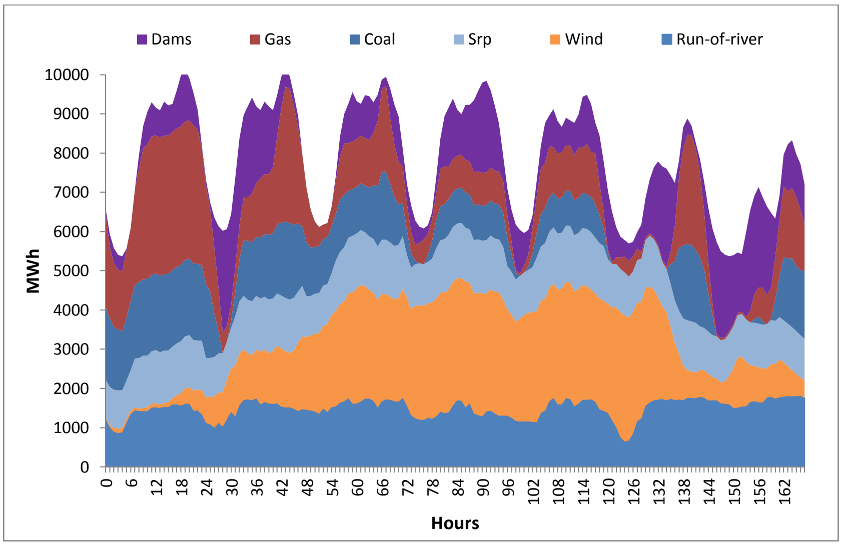


(b) Power production for 50% wind power increase in a Summer week (Simplified model)

Figure 4.6: Summer week with 50% wind power increase simulation results.

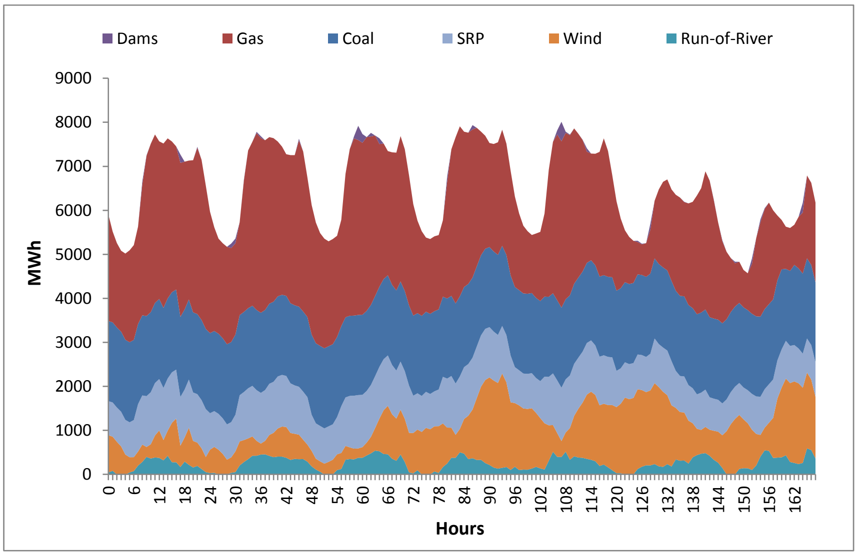


(a) Power production for base scenario in a Winter week (Pereira et al. (2014) model)

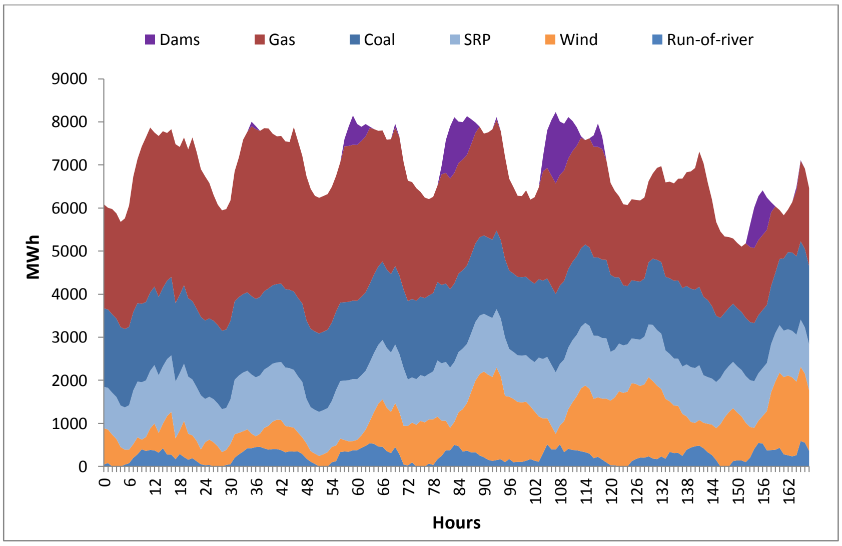


(b) Power production for base scenario in a Winter week (Simplified model)

Figure 4.7: Winter week simulation results.



(a) Power production for base scenario in a Summer week (Pereira et al. (2014) model)



(b) Power production for base scenario in a Summer week (Simplified model)

Figure 4.8: Summer week simulation results.

4.4 Conclusions

This paper propose a simplified approach for the short-term electricity planning. A quadratic penalty function is introduced with the objective of avoiding the use of binary variables associated to minimum up and down time of thermal power groups, ramp considerations, and startup and shutdown restrictions. This will result in a deterministic nonlinear quadratic problem instead of a mixed integer nonlinear one, with significant savings in computational time to obtain an optimal solution. For the model evaluation, a comparison between the simplified approach and the extended model presented in literature (Pereira et al., 2014) is proposed.

The obtained results for the comparison between both models put in evidence that, in general, when the simplified model is applied, the marginal costs of the system tend to decrease comparatively to the extended model. Even with a small influence, the fact that the simplified model does not consider the costs associated to the startups and shutdowns, along with the use of quadratic curves, contributes to this somewhat lower values of the obtained costs. Regarding the amount of CO_2 emissions, the differences between both models are relatively low. In fact, the simplified model tends to have slightly higher values for CO_2 emissions which can come from the lower use of dams in some weeks and from the lower load factor of coal power plants, resulting in higher emission values. Although in most of scenarios CO_2 emissions are higher in the simplified model, a few weeks present lower values than the ones obtained with the extended model, which is due to the higher utilization ratio of the CCGT in detriment of coal power.

The major drawback of the simplified model are the required assumptions to avoid the use of the binary variables. On the other hand, the use of quadratic penalty functions allowed to take into account the operating curves of thermal power plants and represented possible solution to incorporate restrictions related to the number of startups and ramping. Therefore, despite not optimal, the simplified model allows to achieve a compromise between the quality of the electricity system modeling and computational time. In fact, the major advantage of the simplified model, when compared with the extended model, is with respect to the computational time needed for state-of-the-art optimization solvers to provide an optimal solution. While simplified and extended models produce close optimal solutions results, a reduction from 72 hours to 2 minutes was achieved. The simplified model is then considered to be a good option to perform simulations under a large set of scenarios, supporting the selection of a few of them to be subsequently analyzed with the extended Pereira et al. (2014) version if further detail is required.

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Chapter 5

Generation expansion planning with high share of renewables of variable output

Paper submitted for publishing in international journal in March 2015 as Sérgio Pereira, Paula Ferreira, and A.I.F. Vaz. Optimization modelling to support renewables integration in power systems.

ABSTRACT

In this paper, a new generation expansion planning (GEP) model is presented, aiming to integrate in the GEP problem the short-term impacts of variable renewable energy sources (RES) on thermal power plants operating performance. A hourly time step for each year of the time horizon is then considered, resulting in a binary mixed integer non-linear cost optimization model. The proposed model, is then used to design electricity plans for a 10 years planning period for different CO_2 constrained scenarios for a system supported on thermal, hydro and wind power. These plans were compared with the ones obtained with a traditional GEP model, assuming average operating conditions for the thermal power plants. The results demonstrated that RES of variable output has a relevant impact on the short-term operating performance of thermal power plants, and as such these impacts should not be overlooked for the design of long-term strategic plans of the electricity sector. In particular, the proposed integrated model showed that assuming average operating conditions can result on the underestimation of the system cost. This underestimation is more evident for highly CO_2 constrained scenarios due to increasing reliance on RES of variable output. The

proposed integrated approach enables a more realistic computation of the projected system cost and CO_2 emissions that should be considered in the strategic electricity planning.

Keywords: Generation expansion planning; Unit commitment; Renewable energy sources; Optimization problem.

5.1 Introduction

The investment in new technologies, essentially based on renewable resources is increasing. Fossil fuel resource are being used at high rate and the uncertainty surrounding the future supply of fossil fuels is a present concern (Shafiee and Topal, 2009). Besides that, the investment in renewable technologies becomes evident due to the increasing concerns with the environment (Leung and Yang, 2012). Therefore, and in accordance with Lund (2007, pg. 912), "*sustainable energy development strategies typically involve three major technological changes*" including energy savings on the demand side, efficiency improvements in the energy production, and replacement of fossil fuels by various sources of RES.

The commitments that were addressed with the Kyoto protocol were like a lever for the changes in the previous paradigm. The ambitious targets for electricity generation from renewable energies for Europe, can be seen as important mitigation measures in the action against greenhouse gas (GHG) emissions and the threat of large-scale climate change and global warming. The achievement of these compromises are only possible with the investment on RES, where wind power is expected to have a major role (Kabouris and Kanellos, 2010). In fact, the large integration of RES, characterized by their variable output and not subject to dispatch, can bring considerable impacts to the electricity systems. Frequency and voltage regulation, available transmission capacities to accommodate RES plants, connection interfaces in the electric power system and also interference on the operational performance of the traditional power plants such as the increase on the number of startups and shutdowns of thermal power plants and their inefficient use are some of the challenges brought by RES plants (Kabouris and Kanellos, 2010; Albadi and El-Saadany, 2010; Pereira et al., 2014).

Formerly the task of the decision makers was to settle the best size, timing, and type of generation power plants, meting the demand (Hobbs, 1995). The emerging of renewable power plants, essentially wind power, has added a high level of complexity to the electricity sector. In most cases, RES output is variable, difficult to predict well in advance and non-dispatchable. All this has an impact on the electricity system operation forcing other technologies to adapt to these RES conditions and frequently resulting in thermal power plants operating as backup with implications on their efficiency and consequently on the environmental and cost performance of the system. Optimization models remain essential to help in the decision making process, but must clearly recognize the all set of impacts and restrictions brought by the RES power plants.

Usually, when addressing optimization models to electricity sector, two different time horizons are associated. The first, long-term horizon, is addressed to the generation expansion planning (GEP) and according to Hobbs (1995) ranges between 10 and 40 years horizon. These problems will help the decision makers in the strategic decision making process. The second, short-term, is usually addressed to the power plants allocation based on the available resources. Also known as unit commitment and economic dispatch, these problems time horizon usually ranges between 8 hours to 1 week horizon.

Hereupon, the objective of this work is twofold. Firstly, a optimization tool for the strategic GEP problem is aimed, envisaging the inclusion of two different time horizons and resulting in what will be called here after as an integrated model. The proposed approach should allow to include in the GEP problem the short-term impacts of RES on thermal power plants operating performance. Secondly the usefulness of the model will be demonstrated to design possible optimal electricity scenarios in the future, essentially for systems that encompass large wind and hydropower plants. The results detail for each scenario the proposed expansion plans, evaluating aspects such as cost, emissions, and external dependency. A comparison between this model and the already existent model presented in Pereira et al. (2015a) is presented, aiming to evaluate the usefulness of the proposed integrated model.

This paper is organized as follows. Section 5.2 will present an overview over the definition of GEP and unit commitment problems. A set of literature examples will be described to better understanding. In section 5.3 the proposed model formulation will be described. In Section 5.4 a realistic case study of an electricity system with thermal, hydro and wind power plants system is addressed. Both models considered for comparison will be tested and the results of implementation analysed. Finally, conclusions are stated in Section 6.4.

5.2 Generation expansion planning

The definition of the GEP problem seems to be consensual among the overall literature. Must of the authors which work focuses in the GEP problem are in accordance with Meza et al. (2009, pg. 1086), when saying that GEP problem is the problem of *"determining WHAT, WHEN, and WHERE new generation units should be installed over a planning horizon, satisfying the expected energy demand"*. According Karthikeyan et al. (2013), GEP problem is one of the most important decision-making activities in electric utilities. Once more, the author defines this problem as the least-cost GEP that meets forecasted demand. In their work, a differential evolution and self-adaptive differential evolution algorithms have been used for a GEP problem considering 6-year, 14-year and 24-year planning horizons. The main objective of the work was to compare the results with the results obtained using dynamic programming method. In Jonghe et al. (2011) a static linear programming investment model is developed determining the optimal technology mix. A cost minimization problem is addressed having into account that increased variability of the net load profile, due to wind power generation, strongly influences system operation. The author conclude that with the wind capacity increase, the capacity of peak load and high peak load technologies does not need to increase significantly being on the other hand the base load technologies replaced by more flexible mid load generation technologies.

With the changes in the paradigm of the electricity power planning, environmental concerns are getting increasing importance in GEP problems applications. In fact, according to Careri et al. (2011), formerly, GEP problems were faced by vertically integrated utilities aiming to minimize production and capital costs. However, renewable technologies have now a fundamental role on the electricity production systems, demonstrating the increasing importance of the environmental concerns. It is the case of Santos and Legey (2013). In this study, a methodology to incorporate environmental cost to the construction and operation of specific hydro-thermal generation system is addressed. A mixed integer programming problem for the long-term expansion planning is used, minimizing the expansion costs. Also Linares and Romero (2000) have recognized besides the economic dimension, the environmental impacts. In their study, a methodology that combines several multi-criteria methods was proposed and applied to a specific electricity planning case study in Spain, resulting in a multi-objective optimization problem with a planning horizon for the year 2030. Furthermore, environmental concerns applied to GEP problems are seen as being essential to promote society welfare, leading to an increase number of works in literature (see for example Figueira et al. (2005); Li et al. (2010); Cai et al. (2009)).

For Pereira and Saraiva (2013, pg. 41), *"the objective of a GEP problem is to identify the most adequate investment schedule of generation plants together with their sitting and technology to supply the demand considering its possible evolution along the planning period while enforcing some reliability constraints"*. Aside of the GEP problem main goal being the production and capital costs minimization, the introduction of market mechanisms originate major changes in the way decisions are taken. Having this into consideration, Pereira and Saraiva (2010) described a profit maximization optimization approach to address the generation expansion-planning problem in order to help generation companies to decide whether to invest on new assets. Along with the typical constraints ensuring the safe operation of the system, the author considers a set of uncertainties related with the price volatility, the reliability of generation power plants, and the demand evolution.

Although rapid grid penetration of electricity provided through renewable energy utilities is seen as one of the most important GHG mitigation measures, problems in the operation of the electricity system and even environmental and climatic impact of renewable utilities became a reality (Leung and Yang, 2012). Over the last years, the increase growth of renewable installed capacity was obtained in large extension by the wind power sector. Increasing awareness about emissions, climate change, and environmental issues, the awareness about oil and gas reserves depletion and also the improvements in wind turbine technologies were some of the main reasons of this increase (Albadi and El-Saadany, 2010). However, the unpredictability and variability of the RES, became a challenge to the grid operators in the way that it can originate periods of surplus of production, increase hours of thermal power plants working at low load factor and increase number of startups and shutdowns of thermal power plants (Lund and Munster, 2003; Liu et al., 2011; Zhang et al., 2011).

Also known as unit commitment (UC) problem, the aiming of the self-schedule electricity power generation problems is to properly schedule the *on/off* states of all power plants in the system, meeting the predicted load demand, plus the spinning reserve requirement at every time interval minimizing the total cost of production (Senjyu et al., 2003). According to Barth et al. (2006), integration of large amounts of wind power in a liberalized electricity system will impact both the technical operation of the electricity system, specially in what concerns to the requirement of increase capacities of the spinning reserves, and the electricity markets. In Gutiérrez-Martín et al. (2013), the authors refers the renewable energy sources as a measure to reduce GHG. The focus of their study is the interactions between wind generation and thermal plants cycling and the objective is to analyze the contribution of renewable energy to the environment. The results show that CO_2 reductions are still relevant at high wind penetration levels.

It seems evident that for each model, whether it will be used for the GEP problem or for the optimal operation of generation power plants, different concerns are focused. Models for GEP problem, usually proposed for the strategic decision making process, tend to be limited in what concerns to obtaining detailed operation patterns of generation power plants. In fact, according to Jonghe et al., 2011, pg. 2233, long-term investment or GEP problems *"present little information on the inclusion of operational aspects and optimize for a limited number of demand* *levels*". On the other hand, problems like unit commitment or economical dispatch are operation models targeting the best power plants schedule, minimizing cost and having no concerns regarding long-term possible demand growth.

Models able to aggregate both long-term investment and power plants schedule problems are then crucial, specially for systems with high levels of RES with variable output. In line with this concern, Zhang et al. (2013) described a planning model aiming to find the best economic/environmental electricity system commitment considering high level of renewables penetration and new controllable electric devices. The model is firstly used to plan the best technology mix having into account future demand growth and secondly to obtain power plants scheduling, analyzing its behavior using an hour-by-hour time step. A multi-objective optimization model is than applied to a case study of a power generation planning in the Tokyo area out to 2030.

In the next section, the formulation of a new model for long-term strategic generation planning considering both economical/environmental concerns will be described. The model incorporates the impact of renewable generation technologies on other technologies, integrating then the unit commitment problem with the generation expansion planning problem.

5.3 Model formulation

In this section, the formulation followed in this work for the integrated problem, in a system with high penetration of wind and hydropower, is described in detail. The model assumes a set of different fossil fuel plants comprising coal and gas. In what concern hydropower plants, the model assumes two different types: the large hydropower plants with reservoir and the run–of–river plants. Pumping power plants were also included in the model. For the sake of simplicity, wind power was dealt as a single power plant. The same goes for all hydropower technologies. As for coal and gas power plants, these were desegregated in operating groups. This option allowed to fully capture the impacts of RES of variable output on these thermal power groups.

5.3.1 Objective function

The proposed model formulation includes two objective functions. The cost objective function is set up by the sum of fixed and variable costs. The fixed costs are related to both the investment cost of the new power plants and to all fixed operation and maintenance (O&M) costs. The capital investment cost is obtained through the sum of annuities over the planning period, assuming the uniform distribution of the investment cost during the plant lifetime. This approach, although not taking into account the possibility of the accelerated depreciation of technologies, is commonly used for the computation of the levelized cost of electricity for mature technologies in relatively stable markets, as it is assumed in this analysis. Also, being the candidate power technologies already mature, with the possible exception of offshore wind power, changes on the future O&M costs were assumed to be negligible for the ten years planning period. In addition these costs are far from being the determinant ones, as investment and fuel are the major cost drivers. In what concerns to variable costs, those encompass the variable O&M costs, the fuel and pumping costs, and CO_2 emission allowance costs for each power plant. The cost objective function is measured in € and is defined by equation (5.3.1).

$$
\begin{aligned}
&\sum_{t\in T}\sum_{n\in N}\left[\left(Ic_n\frac{j(1+j)^{lt_n}}{(1+j)^{lt_n}-1}+CFOM_n\right)Ip(n,t)\times(1+j)^{-t}\right]+\\
&\sum_{t\in T}\sum_{nGas\in NGas}((new_{nGas}(t,nGas)\times(1-new_{nGas}(t-1,nGas)))\times\\
&Ic_{nGas}\frac{j(1+j)^{lt_{nGas}}}{(1+j)^{lt_{nGas}}-1}+CFOM_{nGas}\Big)Ip(nGas,t)\times(1+j)^{-t}+\\
&\sum_{t\in T}\sum_{nCoal\in NCoal}((new_{nCoal}(t,nCoal)\times(1-new_{nCoal}(t-1,nCoal)))\times\\
&Ic_{nCoal}\frac{j(1+j)^{lt_{nCoal}}}{(1+j)^{lt_{nCoal}}-1}+CFOM_{nCoal}\Big)Ip(nCoal,t)\times(1+j)^{-t}+\\
&\sum_{t\in T}\sum_{tri\in Tri}\left(CVOM_i(t,tri)+TF_c(t,tri)+TE_c(t,tri)\right)(1+j)^{-t}, \quad (5.3.1)
\end{aligned}
$$

where T is the set of the time period (in years) considered in the model for the strategic planning, j is the annual discount rate, N is the set of new wind, hydropower with reservoir and run-of-river power plants included in the system, $NCoal$ is the set of new coal power groups included in the system, $NGas$ is the set of new gas power groups included in the system, $CFOM_n$ is the fixed O&M cost of new wind, hydropower with reservoir and run-of-river power plants included in the system (€/MW), $CFOM_{nCoal}$ is the fixed O&M cost of new coal power groups included in the system (€/MW), $CFOM_{nGas}$ is the fixed O&M cost of new gas power groups included in the system (€/MW), Ic_n is the investment cost of new wind, hydropower with reservoir and run-of-river power plants included in the system (€/MW), Ic_{nCoal} is the investment cost of new coal power groups included in the system (€/MW), Ic_{nGas} is the investment cost of new gas power groups included in the system (€/MW), Ip_n is the installed power of new wind, hydropower with reservoir and run-of-river power plants included in the system (MW), Ip_{nCoal} is the installed power of new coal power groups included in the system (MW), Ip_{nGas} is the installed power of new gas power groups included in the system (MW), $CVOM_i(t, tri)$ is the variable O&M cost of all power plants included in the system in year t for trimester tri (€), $TF_c(t, tri)$ is the fuel cost of each thermal power group considered in the system in the year t for trimester tri (€), $TE_c(t, tri)$ is the emission cost of each thermal power group considered in the system in the year t for trimester tri (€), $new_{nCoal}(t, nCoal)$ is a binary variable that is one if a new coal group is installed and zero if not in year t for trimester tri and $new_{nGas}(t, nGas)$ is a binary variable that is one if a new gas group is installed and zero if not in year t for trimester tri.

The fuel and CO_2 costs of a thermal power group, $ther$, per unit in any given time interval, are usually given as a function of the generator power output or load factor and are represented by quadratic functions. These quadratic functions allow to obtain the fuel and CO_2 costs according to the operating efficiency of each thermal power group. The described model, assumes cost and CO_2 as functions of each generator group load factor, $F_{ther}(L_{ther}(t))$. Following Pereira et al. (2015b) model, cost and CO_2 curves for both coal and natural were considered as presented in Figures 5.1 and 5.2. Therefore, $TF_c(t, tri)$ and $TE_c(t, tri)$ can be computed from equations (5.3.2) and (5.3.3).

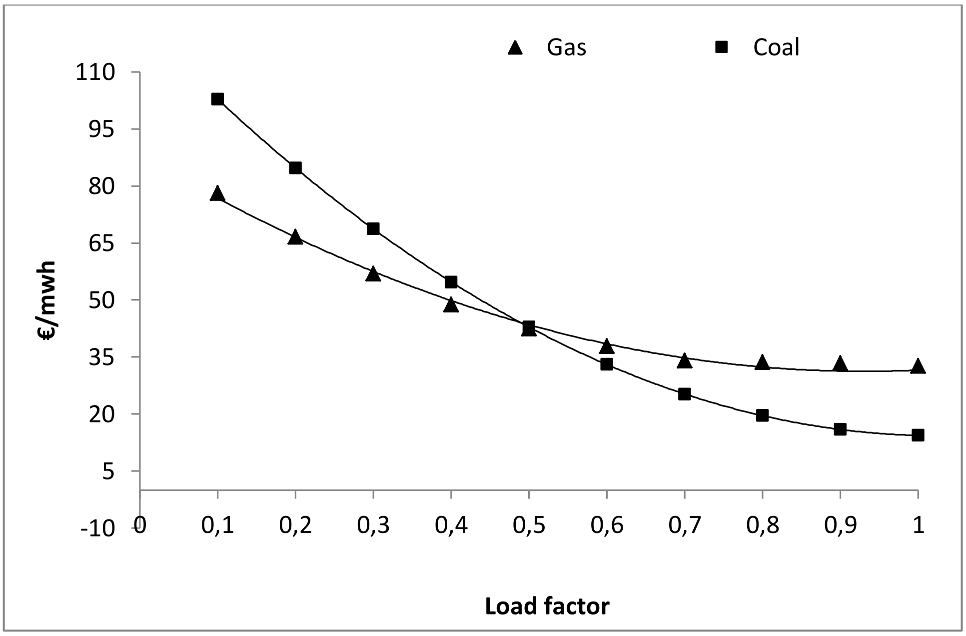


Figure 5.1: Coal and gas fuel cost curves.

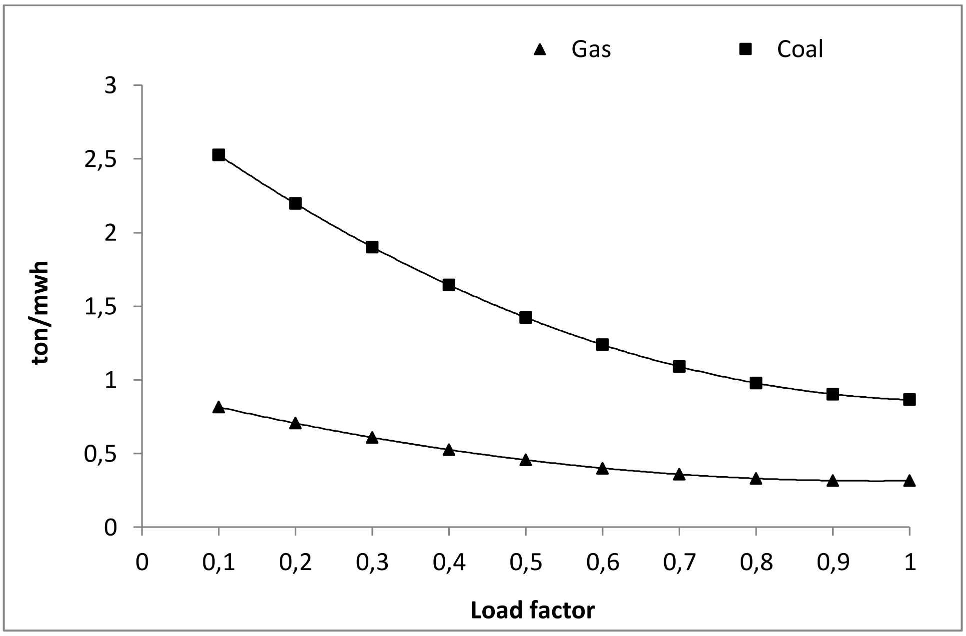


Figure 5.2: Coal and gas CO_2 cost curves.

$$
\begin{aligned}
TF_c(t,tri) = &\sum_{h\in H}\sum_{eGas\in EGas}\left(a^f_{eGas}L^2_{eGas}(t,tri,h,eGas)+b^f_{eGas}L_{eGas}(t,tri,h,eGas)+c^f_{eGas}\right)\times \\
&F(eGas)\times P(t,tri,h,eGas)+ \\
&\sum_{h\in H}\sum_{eCoal\in ECoal}\left(a^f_{eCoal}L^2_{eCoal}(t,tri,h,eCoal)+b^f_{eCoal}L_{eCoal}(t,tri,h,eCoal)+c^f_{eCoal}\right)\times \\
&P(t,tri,h,eCoal)+ \\
&\sum_{h\in H}\sum_{nGas\in NGas} new_{nGas}(t,nGas)\left(a^f_{nGas}L^2_{eGas}(t,tri,h,nGas)+b^f_{nGas}L_{nGas}(t,tri,h,nGas)+c^f_{nGas}\right)\times \\
&F(nGas)\times P(t,tri,h,nGas)+ \\
&\sum_{h\in H}\sum_{nCoal\in NCoal} new_{nCoal}(t,nCoal)\left(a^f_{nCoal}L^2_{nCoal}(t,tri,h,nCoal)\right. \\
&\left.+b^f_{nCoal}L_{nCoal}(t,tri,h,nCoal)+c^f_{nCoal}\right)\times P(t,tri,h,nCoal), \quad (5.3.2)
\end{aligned}
$$

$$TE_c(t,tri) = \sum_{h \in H} \sum_{eGas \in EGas} \left(a^e_{eGas} L^2_{eGas}(t,tri,h,eGas) + b^e_{eGas} L_{eGas}(t,tri,h,eGas) + c^e_{eGas} \right) \times$$
$$EC \times P(t,tri,h,eGas) +$$
$$\sum_{h \in H} \sum_{eCoal \in ECoal} \left(a^e_{eCoal} L^2_{eCoal}(t,tri,h,eCoal) + b^e_{eCoal} L_{eCoal}(t,tri,h,eCoal) + c^e_{eCoal} \right) \times$$
$$EC \times P(t,tri,h,eCoal) +$$
$$\sum_{h \in H} \sum_{nGas \in NGas} new_{nGas}(t,nGas) \left(a^e_{nGas} L^2_{eGas}(t,tri,h,eGas) + b^e_{nGas} L_{eGas}(t,tri,h,eGas) + c^e_{nGas} \right) \times$$
$$EC \times P(t,tri,h,nGas) +$$
$$\sum_{h \in H} \sum_{nCoal \in NCoal} new_{nCoal}(t,nCoal) \left(a^e_{nCoal} L^2_{nCoal}(t,tri,h,nCoal) \right.$$
$$\left. + b^e_{nCoal} L_{nCoal}(t,tri,h,nCoal) + c^e_{nCoal} \right) \times EC \times P(t,tri,h,nCoal), \quad (5.3.3)$$

where H is the set of the time period (in hours) considered in the model for the electricity generation scheduling from all power plants, $ECoal$ is the set of existent coal power groups included in the system, $EGas$ is the set of existent gas power groups included in the system, $P(t,tri,h,i)$ is the electricity power generated by the respective i power plant/group (mwh), a^f, b^f, c^f, a^e, b^e, c^e are the coal and gas quadratic curve coefficients of fuel and CO_2 emissions costs respectively, F_{egas} and F_{ngas} are the fuel cost of new and existent gas power groups (€$/m^3$) and EC is the CO_2 emission allowance cost (€/ton).

The second objective function represents the environmental impact, measured in tons of CO_2, of the system. The CO_2 emissions objective function is defined by equations (5.3.4) and (5.3.5)

$$\sum_{t \in T} \sum_{tri \in TRI} Emi(t,tri). \quad (5.3.4)$$

Where

$$Emi(t,tri) = \sum_{h\in H}\sum_{eGas\in EGas}\left(a^e_{eGas}L^2_{eGas}(t,tri,h,eGas) + b^e_{eGas}L_{eGas}(t,tri,h,eGas) + c^e_{eGas}\right)\times$$
$$P(t,tri,h,eGas)+$$
$$\sum_{h\in H}\sum_{eCoal\in ECoal}\left(a^e_{eCoal}L^2_{eCoal}(t,tri,h,eCoal) + b^e_{eCoal}L_{eCoal}(t,tri,h,eCoal) + c^e_{eCoal}\right)\times$$
$$P(t,tri,h,eCoal)+$$
$$\sum_{h\in H}\sum_{nGas\in NGas} new_{nGas}(t,nGas)\left(a^e_{nGas}L^2_{eGas}(t,tri,h,eGas) + b^e_{nGas}L_{eGas}(t,tri,h,eGas) + c^e_{nGas}\right)\times$$
$$P(t,tri,h,nGas)+$$
$$\sum_{h\in H}\sum_{nGas\in NGas} new_{nCoal}(t,nCoal)\left(a^e_{nCoal}L^2_{eCoal}(t,tri,h,eCoal)\right.$$
$$\left. + b^e_{nCoal}L_{eCoal}(t,tri,h,eCoal) + c^e_{nCoal}\right)\times P(t,tri,h,nCoal). \quad (5.3.5)$$

This objective function is described as the sum of the total CO_2 emissions released from all power plants during the entire planning period.

5.3.2 Constraints

Constraints are equations that impose conditions to the model formulation, defining values of the decision variables that are feasible (Hobbs, 1995). For the specific case of the electricity generation sector, these constraints derived from physical processes, demand requirements, capacity limitations, and legal/policy impositions

Demand Constraint

To ensure the reliability of the system, the production of all power plants should meet the total system load at each hour of planning period and for the entire strategic generation expansion planning. Thus, the demand must be equal to the total power output from power plants plus the special regime producers (SRP[1]) power output minus pumping

[1]SRP includes electricity production from cogeneration and RES power plants excluding large dams, run–of–river and wind plants.

consumption. The mathematical formulation of this constraint is defined by equation (5.3.6).

$$\sum_{i \in I} P(t, tri, h, i) - \sum_{pump \in Pump} P(t, tri, h, pump) + Psrp(t, tri, h) = D(t, tri, h), \quad (5.3.6)$$

where $D(t, tri, h)$ is the demand in hour h of planning for year t and trimester tri (MWh), $Psrp(t, tri, h)$ is the generation output of all special regime producers (except large hydropower plants and wind power plants) including co-generation in hour h of planning for year t and trimester tri (MWh), I is the set of all power plants except pumping plants and $Pump$ is the set of all pumping power plants.

Thermal Power Capacity Constraints with Ramp Considerations

Power capacity constraints ensure that all power groups included in the model will not produce more than the respective group capacity for each hour of the scheduling period. The power output must then be less or equal to the power group capacity, as defined in equations (5.3.7) and (5.3.8). Furthermore, ramp constraints were also considered to ensure a more reliable system representation. Mathematical formulation of these constraints is presented in equations (5.3.9) – (5.3.12).

Max power

$$P(t, m, h, ether) \leq Ipow(ether), \quad (5.3.7)$$

$$P(t, m, h, nther) \leq Ip(t, nther), \quad (5.3.8)$$

where $ether$ is the $ether$ existent thermal power groups, $nther$ is the $nther$ new thermal power groups and $Ipow$ is the installed power of the existent coal and gas power groups.

Ramps

$$P(t, m, h, ether) - P(t, m, h-1, ether) \leq 0.3 \times Ipow(ether), \quad (5.3.9)$$

$$P(t, m, h-1, ether) - P(t, m, h, ether) \leq 0.3 \times Ipow(ether), \quad (5.3.10)$$

$$P(t,m,h,nther) - P(t,m,h-1,nther) \leq 0.3 \times Ip(t,nther), \tag{5.3.11}$$

$$P(t,m,h-1,nther) - P(t,m,h,nther) \leq 0.3 \times Ip(t,nther). \tag{5.3.12}$$

where 0.3 is the assumed maximum percentage (30%) variation of production between two consecutive periods of time as proposed in Pereira et al. (2015b) model.

Large Hydro Constraints

For the large hydropower plants with reservoir, constraints regarding the expected storage and production capacity for each hour of the scheduling period are considered in the model. Equations (5.3.13) – (5.3.15) relate the reservoir level for the hour h in terms of the previous reservoir level, inflows, and consumption.

$$\begin{aligned} reserve(t,tri) = Ir + Inflows(t,tri) \times \left(\frac{(Ip(t,nHa) + Ip(t,eHa))}{Ip(t,eHa)}\right) - \\ \left(\sum_{nHa \in NHydro} \sum_{h \in H} P(t,tri,h,nHa) + \sum_{eHa \in EHydro} \sum_{h \in H} P(t,tri,h,eHa)\right) + \\ \left(\sum_{npump \in Pump} \sum_{h \in H} \eta_{npump} * P(t,tri,h,npump) \sum_{epump \in Pump} \sum_{h \in H} \eta_{epump} * P(t,tri,h,epump)\right) \\ t = 1 \quad and \quad tri = 1, \end{aligned} \tag{5.3.13}$$

$$\begin{aligned} reserve(t,tri) = reserve(t-1,4) + Inflows(t,tri) \times \left(\frac{(Ip(t,nHa) + Ip(t,eHa))}{Ip(t,eHa)}\right) - \\ \left(\sum_{nHa \in NHydro} \sum_{h \in H} P(t,tri,h,nHa) + \sum_{eHa \in EHydro} \sum_{h \in H} P(t,tri,h,eHa)\right) + \\ \left(\sum_{npump \in Pump} \sum_{h \in H} \eta_{npump} * P(t,tri,h,npump) \sum_{epump \in Pump} \sum_{h \in H} \eta_{epump} * P(t,tri,h,epump)\right) \\ \forall t \in T \setminus \{1\} \quad and \quad tri = 1, \end{aligned} \tag{5.3.14}$$

$$reserve(t,tri) = reserve(t,tri-1) + Inflows(t,tri) \times \left(\frac{(Ip(t,nHa) + Ip(t,eHa))}{Ip(t,eHa)}\right) -$$
$$\left(\sum_{nHa \in NHydro} \sum_{h \in H} P(t,tri,h,nHa) + \sum_{eHa \in EHydro} \sum_{h \in H} P(t,tri,h,eHa)\right) +$$
$$\left(\sum_{npump \in Pump} \sum_{h \in H} \eta_{npump} * P(t,tri,h,npump) \sum_{epump \in Pump} \sum_{h \in H} \eta_{epump} * P(t,tri,h,epump)\right)$$
$$\forall t \in T \setminus \{1\}, \quad \forall tri \in Tri \setminus \{1\} \quad (5.3.15)$$

where Ir is the initial reserve in the reservoir, $reserve(t,tri)$ is the reservoir level on trimester tri of the year t, $Inflows(t,tri)$ is the hydro inflow on trimester tri of the year t, nHa is the nHa hydropower plant with reservoir belonging to the set of all new hydropower plants $NHydro$, eHa is the eHa hydropower plant with reservoir belonging to the set of all existent hydropower plants $EHydro$ and η_{epump} and η_{npump} are the efficiency of pumping plants, usually around 70%.

Additional upper and lower bounds must be used to define maximum and minimum reservoir levels, as represented in equations (5.3.16) and (5.3.17).

$$reserve(t,tri) \leq maxR\left(\frac{(Ip(t,nHa) + Ip(t,eHa))}{Ip(t,eHa)}\right) \quad (5.3.16)$$

$$reserve(t,tri) \geq 0.2 \times maxR\left(\frac{(Ip(t,nHa) + Ip(t,eHa))}{Ip(t,eHa)}\right) \quad (5.3.17)$$

where $maxR$ is the maximum reservoir level allowed.

In what concerns to electricity generation from hydropower plants, equations (5.3.18) and (5.3.19) were used to impose the maximum production limit for each plant.

$$P(t,tri,h,nHa) \leq Ip(t,nHa) \quad (5.3.18)$$

$$P(t,tri,h,eHa) \leq Ipow(t,eHa) \quad (5.3.19)$$

where $Ipow(t, eHa)$ is the installed power of the existent large hydropower power plants and $Ip(t, nHa)$ is the installed power of the new large hydropower power plants.

The next set of constraints imposes that the production of run-of-river power plants should be equal to the installed power, taking into consideration the availability which depends on the year seasonality. This type of plants are characterized by its reduced storage capacity and can be represented mathematically by equations (5.3.20) and (5.3.21).

$$P(t, tri, h, nHr) \leq Ip(t, nHr) \times \phi(tri, h) \tag{5.3.20}$$

$$P(t, tri, h, eHr) \leq Ipow(t, eHr) \times \phi(tri, h) \tag{5.3.21}$$

where eHr is the eHr run-of-river hydropower plant belonging to the set of all existent hydropower plants $EHydro$, nHr is the nHr run-of-river hydropower plant belonging to the set of all new hydropower plants $NHydro$ and $\phi(tri, h)$ is the run–of–river plants availability in trimester tri that is strongly seasonally dependent.

Pumping Constraints

For the mathematical formulation of the operation of hydropower plants with pumping capacity, two reservoirs must be taken into account. The upper one storages water from inflows and from pumping itself, while the lower one storages water already used for electricity generation that later may be pumped again to the upper level. Again a set of constraints are necessary to model the initial pumping reserve for the first hour of planning period. These constraints are defined by equations (5.3.22) – (5.3.24).

$$\begin{aligned} reserve_p(t, tri) = IR_p + \\ \left(\sum_{nHa \in NHydro} \sum_{h \in H} P(t, tri, h, nHa) + \sum_{eHa \in EHydro} \sum_{h \in H} P(t, tri, h, eHa) \right) - \\ \left(\sum_{npump \in Pump} \sum_{h \in H} \eta_{npump} * P(t, tri, h, npump) \sum_{epump \in Pump} \sum_{h \in H} \eta_{epump} * P(t, tri, h, epump) \right) \\ t = 1 \quad and \quad tri = 1, \end{aligned} \tag{5.3.22}$$

$$reserve_p(t,tri) = reserve_p(t-1,4) + \left(\sum_{nHa \in NHydro} \sum_{h \in H} P(t,tri,h,nHa) + \sum_{eHa \in EHydro} \sum_{h \in H} P(t,tri,h,eHa) \right) - \left(\sum_{npump \in Pump} \sum_{h \in H} \eta_{npump} * P(t,tri,h,npump) \sum_{epump \in Pump} \sum_{h \in H} \eta_{epump} * P(t,tri,h,epump) \right) \quad \forall t \in T \setminus \{1\} \quad and \quad tri = 1, \tag{5.3.23}$$

$$reserve_p(t,tri) = reserve_p(t,tri-1) + \left(\sum_{nHa \in NHydro} \sum_{h \in H} P(t,tri,h,nHa) + \sum_{eHa \in EHydro} \sum_{h \in H} P(t,tri,h,eHa) \right) - \left(\sum_{npump \in Pump} \sum_{h \in H} \eta_{npump} * P(t,tri,h,npump) \sum_{epump \in Pump} \sum_{h \in H} \eta_{epump} * P(t,tri,h,epump) \right) \quad \forall t \in T \setminus \{1\}, \forall tri \in Tri \setminus \{1\} \tag{5.3.24}$$

where Ir_p is the initial reserve in the lower reservoir and $reserve_p(t,tri)$ is the lower reservoir level on trimester tri of the year t.

Again, in what concerns to the generation from hydropower pumping plants, the set of constraints defined by equation (5.3.25) and (5.3.26) were used.

$$P(t,tri,h,npump) \leq Ip(t,npump), \tag{5.3.25}$$

$$P(t,tri,h,epump) \leq Ipow(t,epump), \tag{5.3.26}$$

Wind constraints

This constraint ensures wind power generation capacity to be equal to the total installed power taking into account the wind availability. This constraint is set as an equality assuming that wind power is not subject to dispatch, and has priority access to the grid. Wind constraint are described by equations (5.3.27) and (5.3.28)

$$P(t, tri, h, eWind) = \alpha(tri, h) \times Ipow(t, eWind) \tag{5.3.27}$$

$$P(t, tri, h, nWind) = \alpha(tri, h) \times Ip(t, Wind) \tag{5.3.28}$$

where $eWind$ is the $eWind$ wind power plant belonging to the set of all existent wind plants $EWind$, $nWind$ is the $nWind$ wind power plant belonging to the set of all new wind plants $NWind$ and $\alpha(tri, h)$ is the wind availability in trimester tri for each hour h.

Thermal modular capacity and Renewable potential

In order to define maximum modular capacity for the thermal power groups as well as the renewable maximum potential, a set of constraints must be used as described in equations (5.3.29) and (5.3.30) for gas and coal power groups, equations (5.3.31) and (5.3.32) for wind power plants and equation (5.3.33) for hydropower plants.

$$Ip(t, nGas) = new_{nGas}(t, nGas) \times mc(nGas), \tag{5.3.29}$$

$$Ip(t, nCoal) = new_{nCoal}(t, nCoal) \times mc(nCoal), \tag{5.3.30}$$

$$Ip(t, Onshore) \leq ONV, \tag{5.3.31}$$

$$Ip(t, Offshore) \leq OFV, \tag{5.3.32}$$

$$Ip(t, nHydro) + Ip(t, nHr) \leq HP, \tag{5.3.33}$$

where $mc(nGas)$ and $mc(nCoal)$ are the capacity of each new gas and coal considered module, ONV and OFV are the wind onshore and offshore potential respectively and HP is the hydropower potential.

Security constraints

The reserve margin (RM) constraint, presented in equation 5.3.34, ensures the security of the system, taking into account the non-usable capacity, which includes the capacity that cannot be scheduled due to reasons like the temporary shortage of primary energy resources, affecting in particular the hydro and wind power plants. Using this restriction, the model, explicitly takes into account the impact that the increasing hydro and wind capacity, will have on the RM requirements (for a detailed description please refer to Ferreira (2008)). Furthermore, power plants outages although not being frequent must be considered and prevented. These outages have different reasons for happen consisting essentially on the power plants breakdown and stoppages for maintenance. Besides that, suddenly increase of power consumption that may occur must be taken into considerations. Thus, equations (5.3.34) and (5.3.35) are essential when scheduling the power plants subject to dispatch, maintaining the reliability of the system.

$$
\begin{aligned}
RM \left(\sum_{n \in I_N} Ip(t,n) + \sum_{e \in I_E} Ipow(t,e) + IPsrp(t) \right) \leq \\
\sum_{n \in I_N} Ip(t,n) + \sum_{e \in I_E} Ipow(t,e) + IPsrp(t) - \\
(LW \times (\sum_{nWind \in NWind} Ip(t, nWind) + \sum_{eWind \in EWind} Ipow(t, eWind)) \\
+ LH \times (\sum_{nHydro \in NHydro} Ip(t, nHydro) + \sum_{eHydro \in EHydro} Ipow(t, eHydro)) + \\
LSRP \times IPsrp(t) + LBHG + LBTG - Pl(t)) \qquad \forall t \in T,
\end{aligned} \tag{5.3.34}
$$

where I_N and I_E are the set of all new and existent power plants respectively, RM is the set reserve margin of system, $IPsrp$ is the installed power of SRP in year t, LW is the potential reduction of wind power due to the lack of wind, LH is the potential reduction of hydropower due to a dry regime, $LSRP$ is the potential loss of SRP due to an unfavorable regime and $LBHG$ and $LBTG$ represent the lost of biggest hydro and thermal power groups. $Pl(t)$ is the system peak load in year t.

$$
\begin{aligned}
\sum_{ether \in ETher} & (Ipow(t, ether) - P(t, tri, h, ether)) \\
& + \sum_{nther \in NTher} (Ip(t, nther) - P(t, tri, h, nther)) \\
& + \sum_{eHa \in EHydro} (Ipow(t, eHa) - P(t, tri, h, eHa)) \\
& + \sum_{nHa \in NHydro} (Ip(t, nHa) - P(t, tri, h, nHa)) \geq D(t) \times \beta, \quad (5.3.35)
\end{aligned}
$$

where $ETher$ is the set of all existent thermal power groups, $NTher$ is the set of all new thermal power groups, and β is the parameter that will ensure the reliability of the system and usually represent 10%.

5.4 Model implementation

In this section, the model proposed in section 5.3 is tested and analysed for a wind-hydro-thermal power system. Besides guiding the application and presenting the analysis of the results, a comparison between integrated model and the model described in Pereira et al. (2015a) will be considered. The major goal is to evaluate if and the use of the integrated model, explicitly accounting for short term impacts on GEP, would lead to different results of the ones obtained in the traditional GEP model, relying on average operating conditions.

5.4.1 Case study

The optimization model described in section 5.3 was designed with the final aim of being used for the strategic electricity power planning integrating the power plants allocation based on the available resources, in the analysis of a mixed hydro-wind-thermal power system. All the electricity power generation technologies referred above were considered, highlighting in particular the impacts that an increase of wind power capacity have in the system. For that, the particular case of the Portuguese electricity system was selected.

In the last few years, the increase of RES power, mostly wind power, was evident as reflected in Figure 5.3. According to DGEG (2014) and analyzing Figure 5.4, in 2014 the production of electricity through wind power was only surpassed by hydropower. Until 2011, hydropower combined with coal and gas power plants were the major electricity producers in Portugal (REN, 2011). All this commitment was translated in a share of 62% of production derived from RES, verified in the end of 2014.

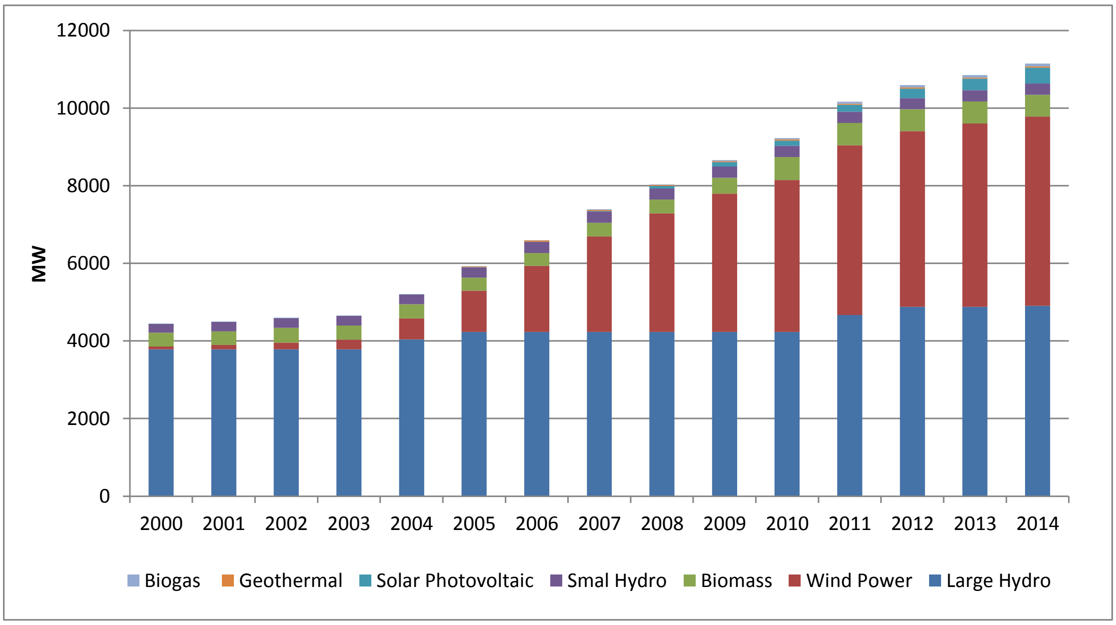


Figure 5.3: Evolution of RES for electricity in Portugal (Own elaboration (DGEG, 2014)).

Although in the last years a higher importance has been given to the renewables in the Portuguese electricity system, its share in the electricity system is highly dependent of the seasonality of the year. Contrary to year 2014 where wind and hydropower generation was 11.8 and 14.6 TWh respectively, in 2011, wind and hydropower generation was 9 and 10.8 TWh respectively. This is justified by the higher wind and hydro availability during 2014 which lead to a reduction of electricity generation provided by thermal power plants. This reduction was from 19.4 TWh in 2014 to 12.4 TWh in 2011. For that has contributed the reduction of electricity generation from natural gas power plants, from 10.3 TWh in 2011 to 1.4 TWh in 2014 (REN, 2011, 2014). This is mostly due to the CCGT technical characteristics that allows easily and more rapidly to compensate both wind and hydro seasonal variability. On the contrary, coal power plants, characterized by its lower flexibility and for working as base load power plants, tend to keep its generation constant, having contributed with 10.3 and 11 TWh respectively in 2011 and 2014.

Furthermore, the increase of RES in the electricity system is also seen as a measure to mitigate the electricity dependency. For that, along with the increasing share of RES and with the thermal power generation reduction, the reduction of the electricity importation presents a valuable contribution. This can be seen, for example, in REN (2011) and REN (2014) where a reduction in the importations, from 2.8 TWh in 2011 to 0.9 TWh in 2014, is evidenced.

In the next sub-section, results addressing the impacts of increasing share of RES in the system will be analysed.

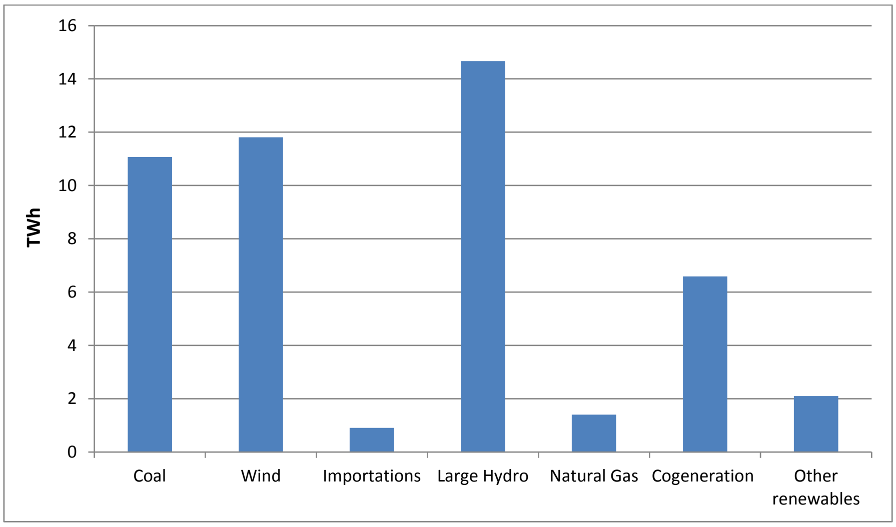


Figure 5.4: Electricity production in 2014 (Own elaboration (REN, 2014)).

5.4.2 Used approach and numerical results

The proposed model described in section 5.3 was coded in GAMS (2011). DICOPT solver, that is interfaced with GAMS, was selected to obtain the numerical results reported herein. The numerical results were obtained in a Microsoft Windows operating system using a Intel® CORE™i5-2410M CPU @ 2.3GHz computer with 8GB of memory.

A multi-objective problem with a period of ten years horizon was considered for the strategic electricity planning of a mix thermal-wind-hydropower system. Since an integrated model is proposed, for each year of the strategic electricity planning, the model considers the individual commitment of each thermal power group. To this end, a hourly time step, usually used for the problem of UC, allowing to get a more accurate representation of all technical characteristics of power plants, was considered. The result is a mix integer nonlinear optimization problem (MINLP). Due to the high complexity of the problem and consequently increase of computational effort, the model considers a set of 24 hours, one day, per season of the year. For each one of the seasons of the year, characteristic renewable availability as well as demand consumption were taken into consideration. In line with this, 4 trimesters were considered assuming that each one would be represented by the considered 24 hours period.

As starting point, a total of 23 different thermal power groups, comprising coal and gas, were considered. In what concerns to wind power, all individual power plants were aggregated and dealt as a single power plants. The same principle was considered for the large hydropower plants, however in this case, three different groups were included: the large hydropower plants with reservoir, the run-of-river power plants, and the pumping power plants.

The problem was addressed by solving eight single-objective optimization problems. Firstly, a single-objective optimization problem was solved for each objective function, using equations (5.3.6)– (5.3.35) as constraints and equation (5.3.1) and (5.3.4) for cost and emissions minimization respectively. The remaining 6 cost optimization problems, each one constrained by a fixed value for the total emissions for the 10 years planning period (80, 70, 60, 50, 40, and 30 Mton), allowed to design the Pareto front shown in Figure 5.5.

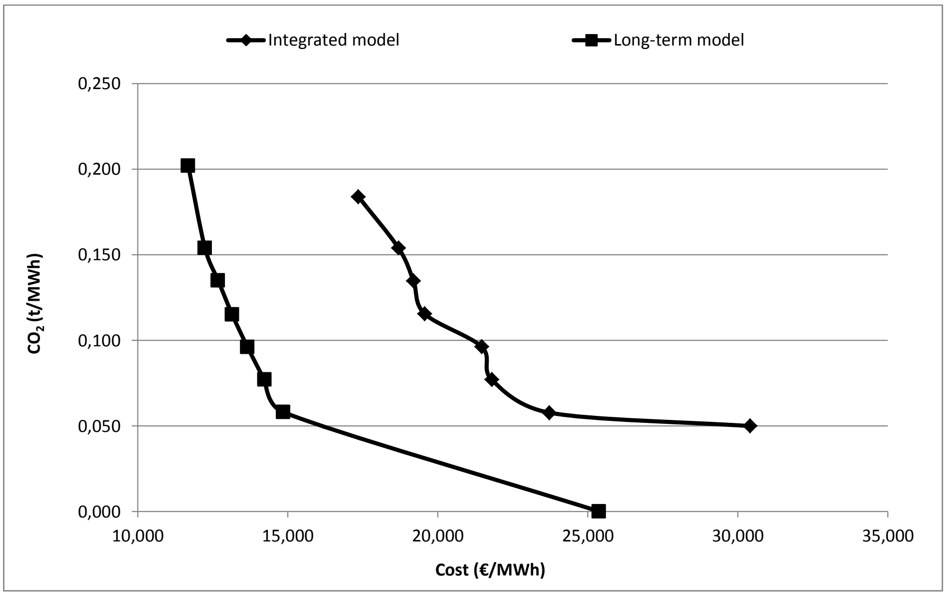


Figure 5.5: Pareto curve solutions

A comparison between this new integrated model and the model for the strategic electricity power planning described in Pereira et al. (2015a) was attempted. Table 5.1 show the results obtained when using both models, detailing the total and average cost and emission for the extreme solutions.

Observing Table 5.1 is possible to verify that the cost over the entire planning period tends to be higher when

Table 5.1: Optimal objective functions solutions

	Cost (M€)	CO_2 (Mton)	Cost (€/MWh)	CO_2 (ton/MWh)
	Integrated Model			
Optimal cost solution	9019	95.5	17.358	0.184
Optimal emission solution	15803	25.9	30.414	0.05
	Pereira et al. (2015a) model			
Optimal cost solution	6071	104.8	11.685	0.202
Optimal emission solution	13186	0.625	25.378	0.00012

integrated model is used. In what concerns emission values, the results of the integrated model are strongly influenced by both the assumed short-term technical restrictions for thermal power plants and the hourly variability of wind and hydropower output. This turns more difficult to find a obvious trend on the extreme solution results. However, Figure 5.5 clearly demonstrates that for each one of the assumed CO_2 values, the cost obtained with the integrated model is higher than the one obtained with Pereira et al. (2015a) model. These differences result from the higher reliance on CCGT to backup hydro and wind power hourly variability, with higher fuel costs but lower emissions than coal power plants (Pereira et al., 2014). This increase of CCGT power output is demonstrated in figures 5.6 – 5.9. The higher emission values obtained in the solutions for the integrated model are also justified by the thermal power groups operating constraint, penalizing systems with high RES share.

The tradeoff between costs and CO_2 emissions for both models simulations, represented in the form of Pareto curve, is shown in Figure 5.5. For both models it is evident that as more restrictive CO_2 emissions values are considered, the cost of the system tend to increase while CO_2 emissions decrease. This happens mostly because the achievement of CO_2 emissions targets are only possible by investing in RES technologies, and reducing electricity production from the more pollutant thermal power groups. Figures 5.10 to 5.13 and Figures 5.14 to 5.17 show precisely this behavior. For example, analysing Figures 5.10 to 5.13 is possible to verify that as the way that a reduction in the CO_2 emission occurs, from 80 Mton to 30 Mton, the generation of electricity from coal power groups decreases. This lack of generation is compensated by natural gas power groups generation and by the investment in new run–of–river power plants. Note for example that for the case of Figure 5.13, from 2015 forward, the electricity generation from coal power groups will be 0. On the opposite way, in Figure 5.10 the electricity generation from natural gas is residual. Another aspect to take into account is that the investment in new wind power plants only occurs for more extreme point solutions, as demonstrated in Figure 5.9. This can be explained by the high cost investment associated to wind technology.

In a general way, the behavior observed when using the Pereira et al. (2015a) model is followed by the integrated model. However, the fact that the integrated model consider the commitment of thermal groups, allows to obtain the results closer to the real operation of the electricity system, resulting in both higher costs and higher emissions. System behavior when using integrated model can be seen in Figures 5.14 to 5.17. Also for this model the reduction of coal power production is evident as CO_2 restrictions are imposed. In fact, looking to Figure 5.17 is possible to verify that there is no electricity generation derived from the existent coal power groups. This is compensated by the increase production of the gas power groups, and by the investment in new technologies including gas, coal and RES power plants. Note that new generation plants like coal power plants are more efficient than the older ones which allows to reduce the amount of CO_2 emissions. Other difference when comparing with the Pereira et al. (2015a)

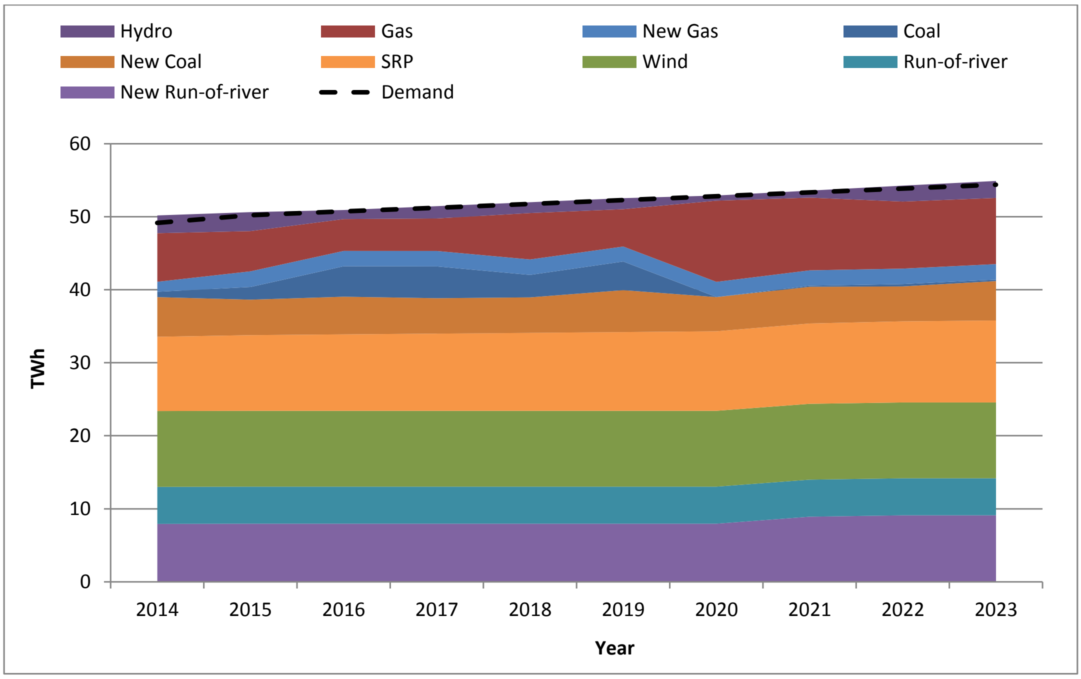


Figure 5.6: Power production for minimum cost solution using integrated model

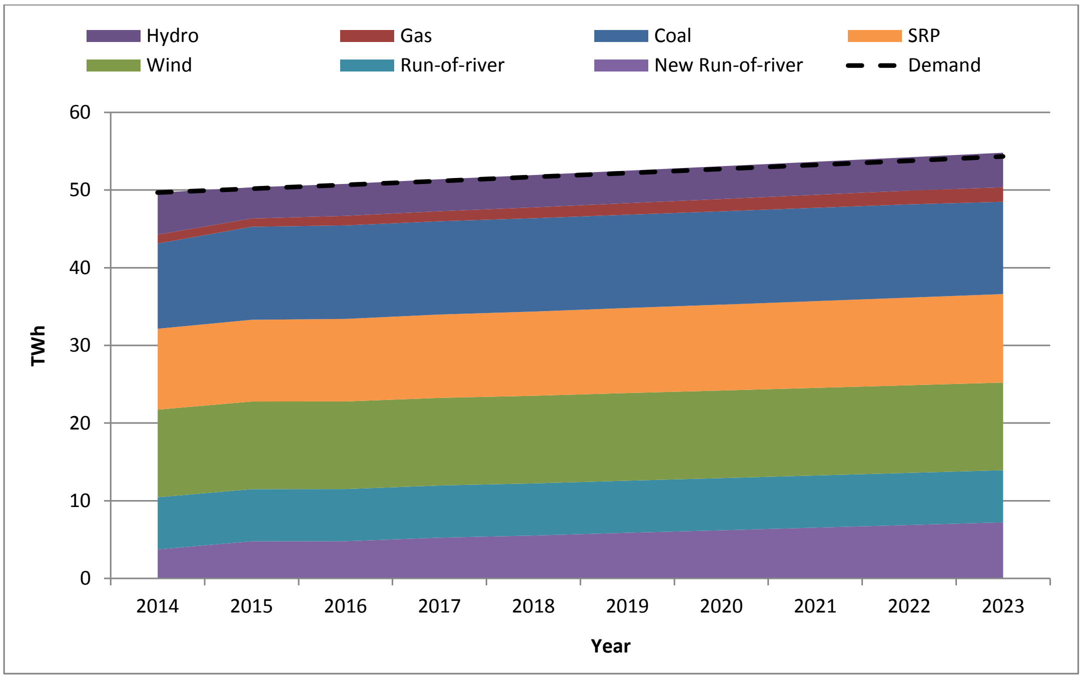


Figure 5.7: Power production for minimum cost solution using Pereira et al. (2015a) model

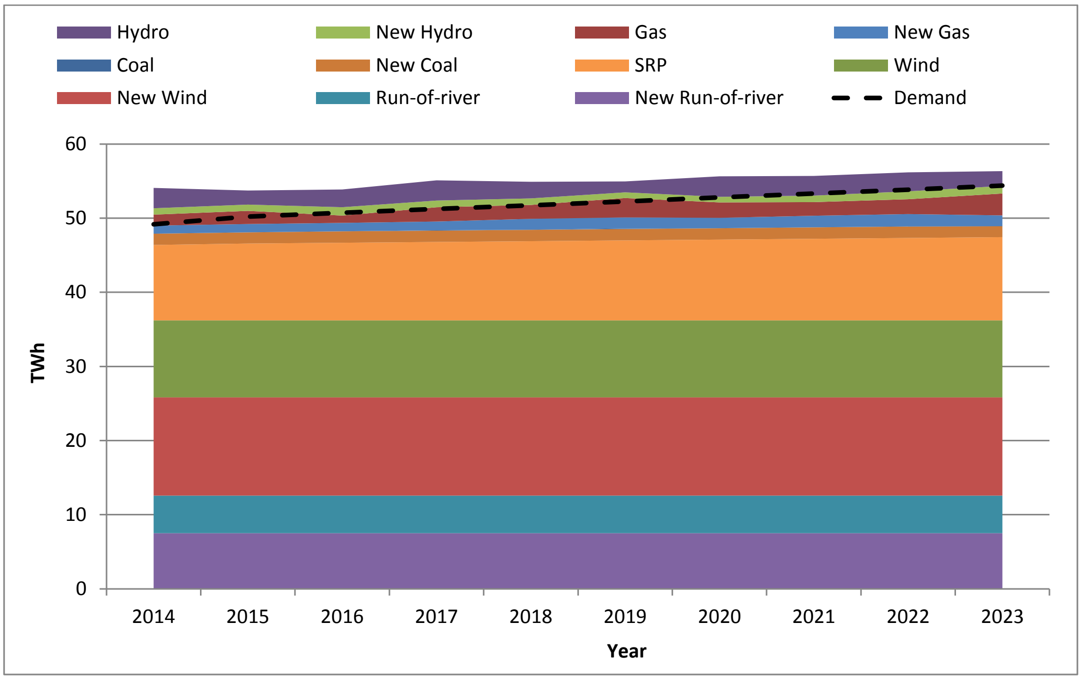


Figure 5.8: Power production for minimum emissions solution using integrated model

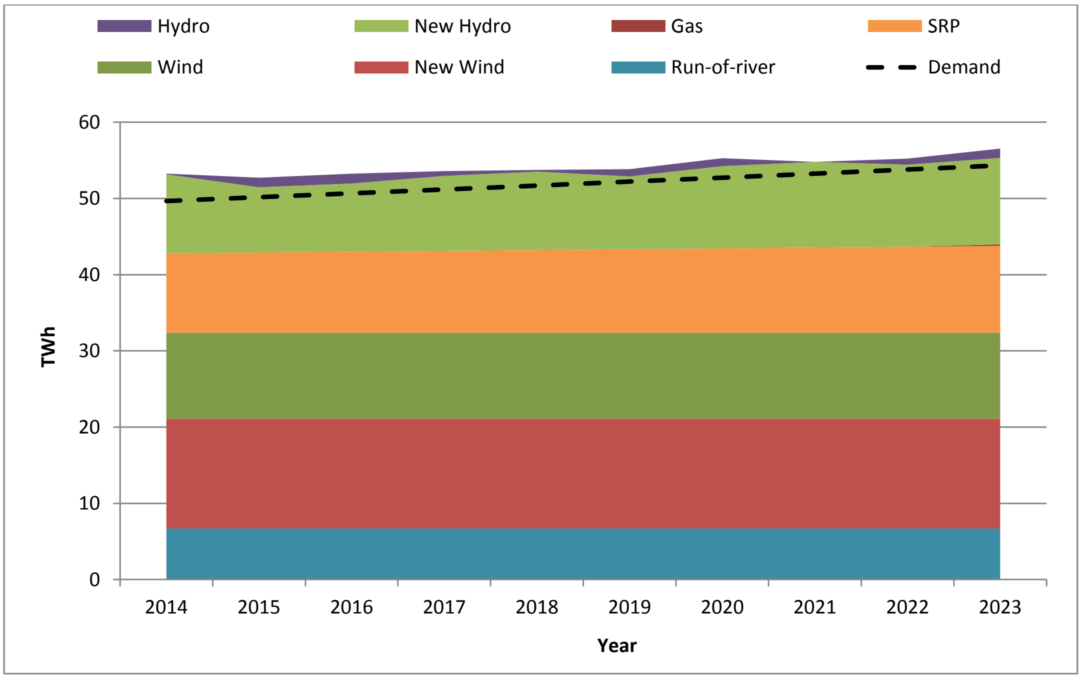


Figure 5.9: Power production for minimum emissions solution using Pereira et al. (2015a) model

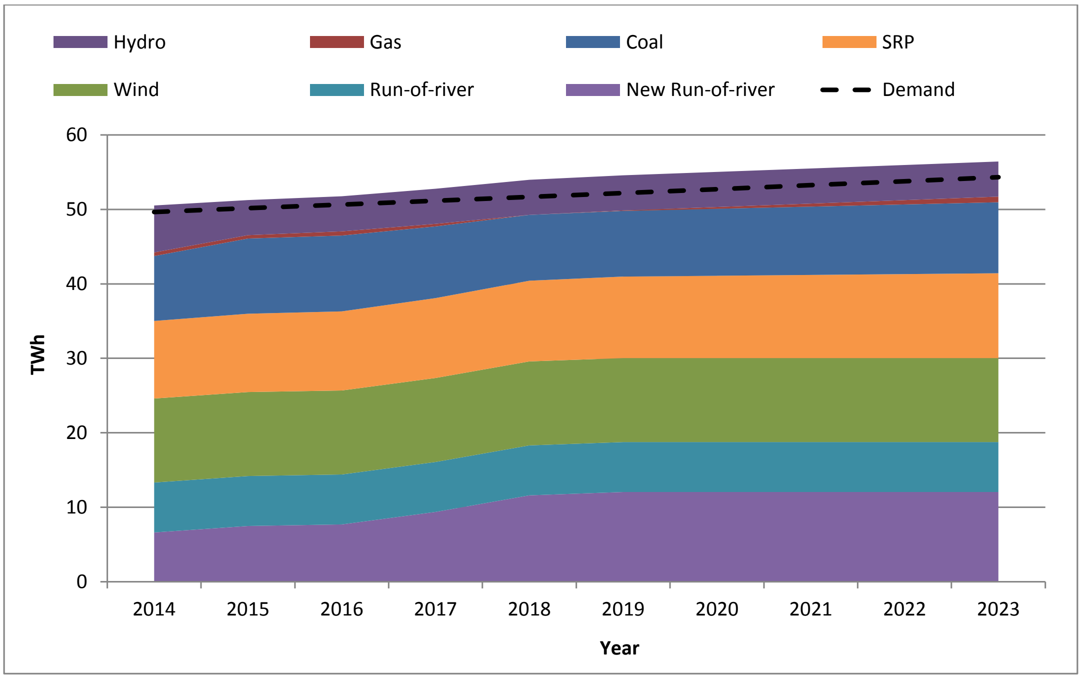


Figure 5.10: Power production solutions for intermediate Pareto curve values of emissions using Pereira et al. (2015a) model (80Mton).

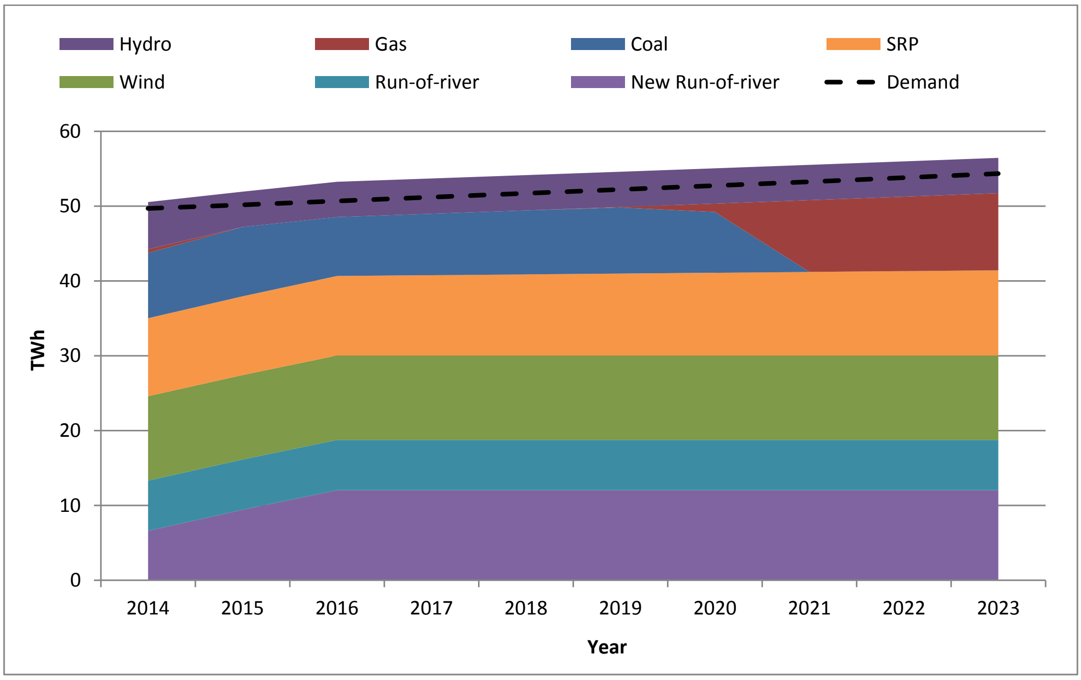


Figure 5.11: Power production solutions for intermediate Pareto curve values of emissions using Pereira et al. (2015a) model (60Mton).

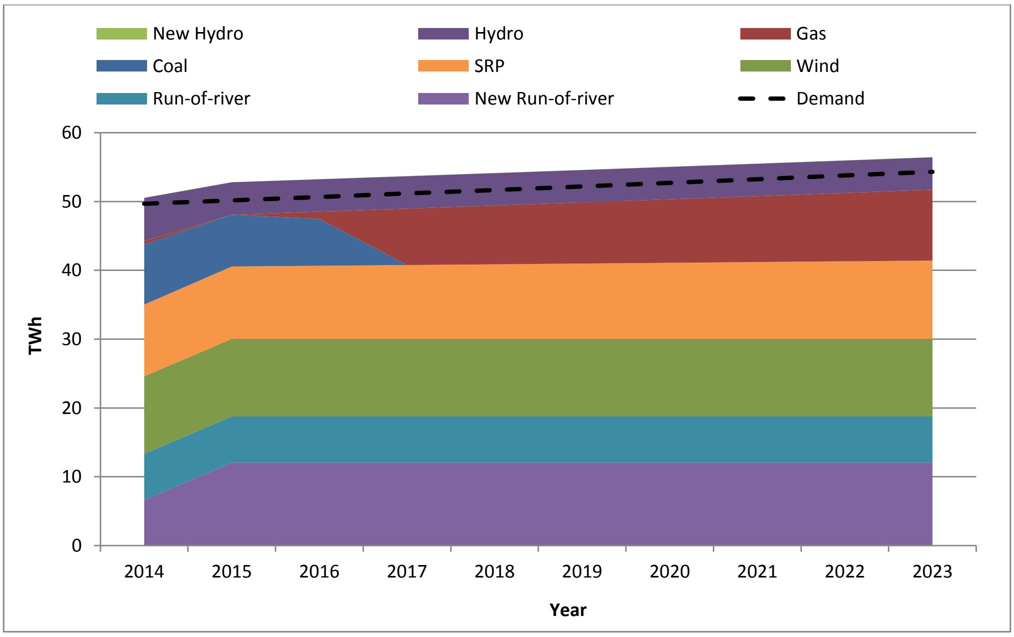


Figure 5.12: Power production solutions for intermediate Pareto curve values of emissions using Pereira et al. (2015a) model (40Mton).

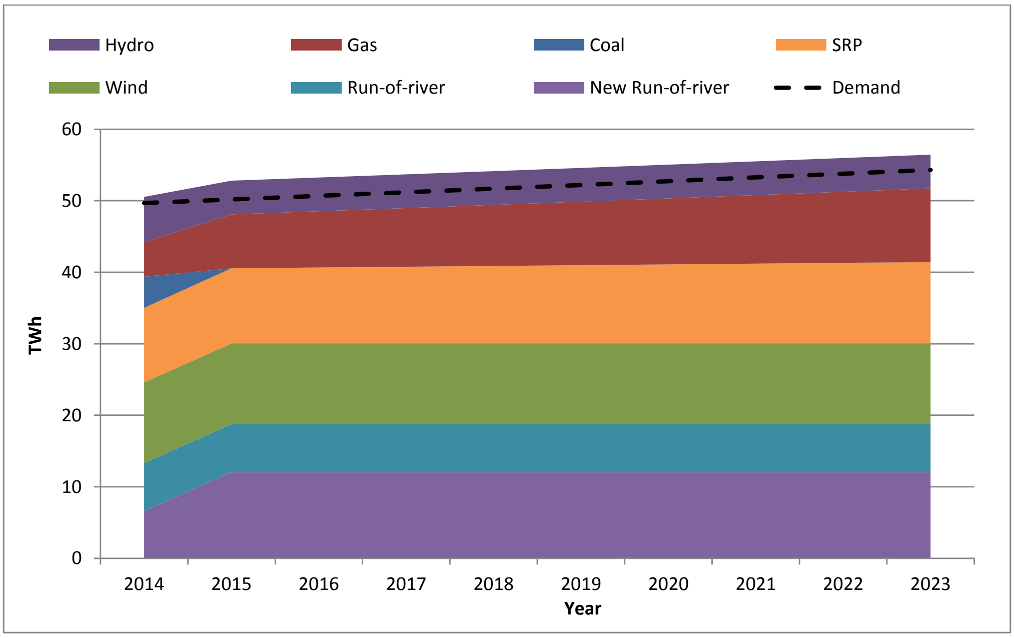


Figure 5.13: Power production solutions for intermediate Pareto curve values of emissions using Pereira et al. (2015a) model (30Mton).

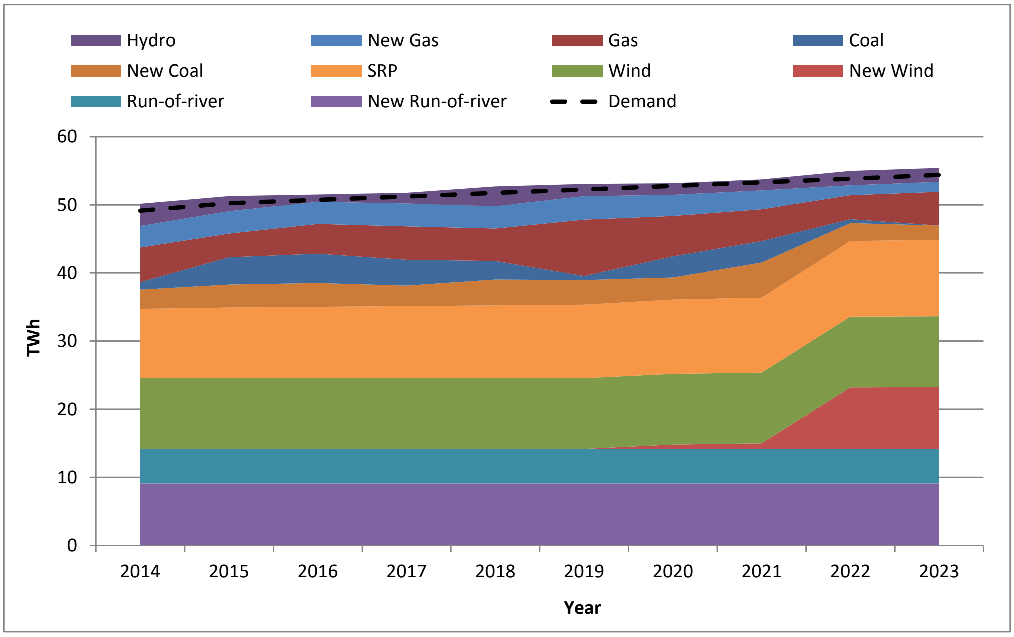


Figure 5.14: Power production solutions for intermediate Pareto curve values of emissions using integrated model (80Mton).

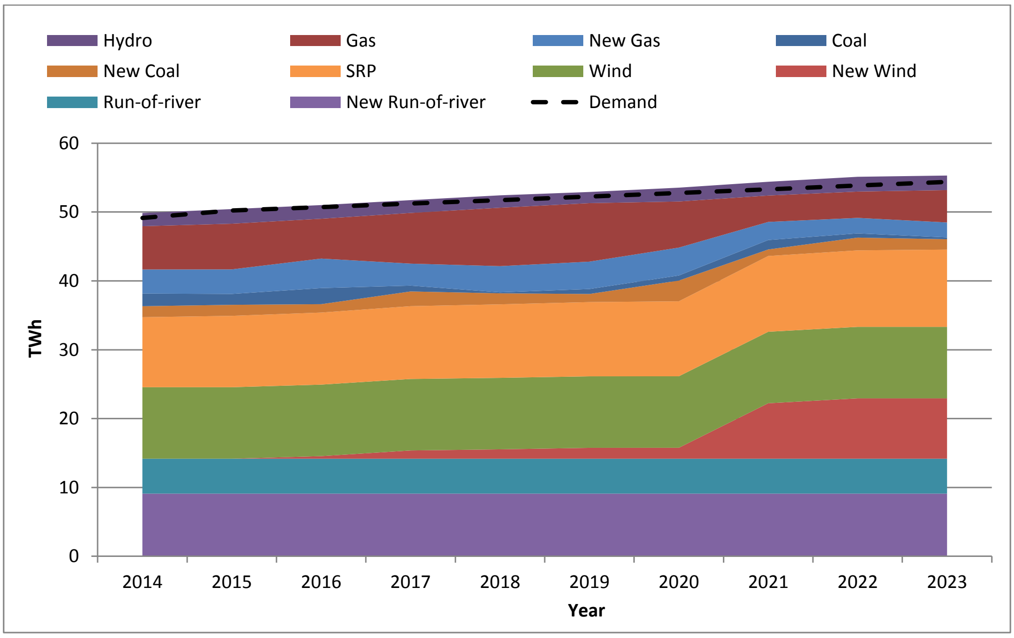


Figure 5.15: Power production solutions for intermediate Pareto curve values of emissions using integrated model (60Mton).

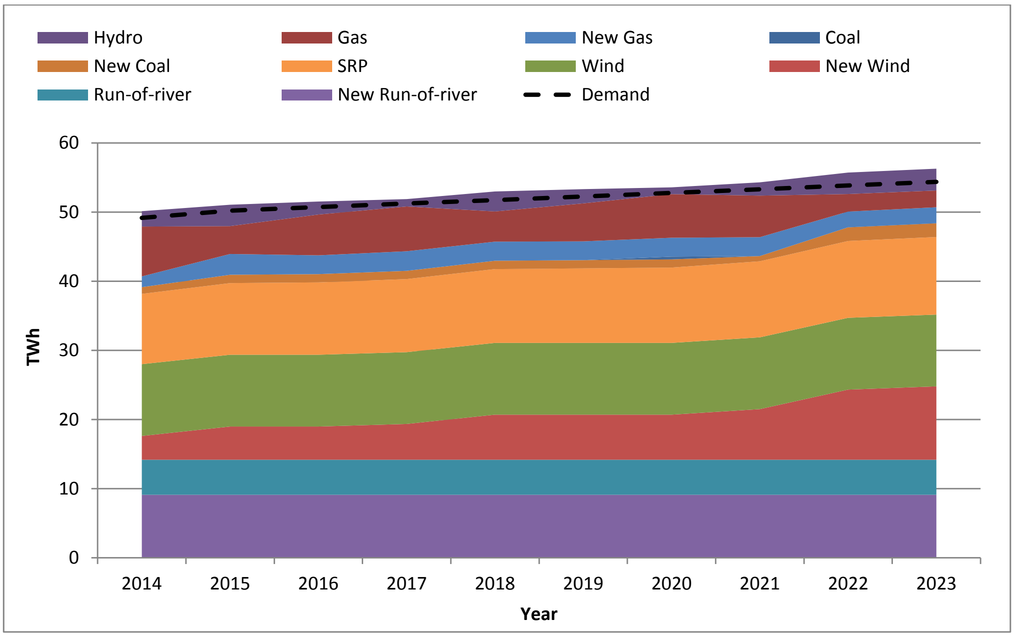


Figure 5.16: Power production solutions for intermediate Pareto curve values of emissions using integrated model (40Mton).

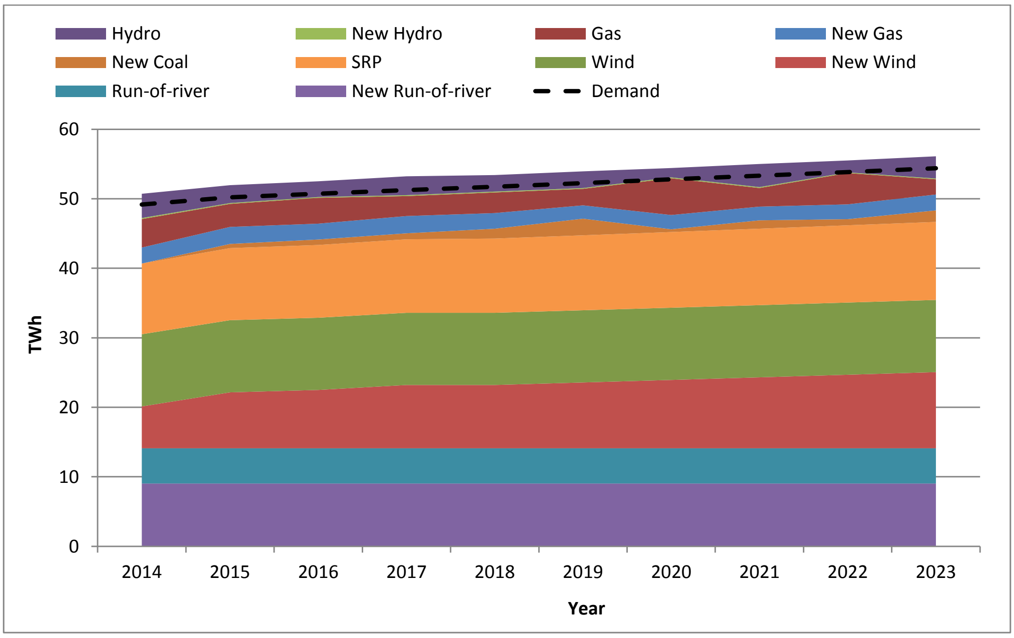
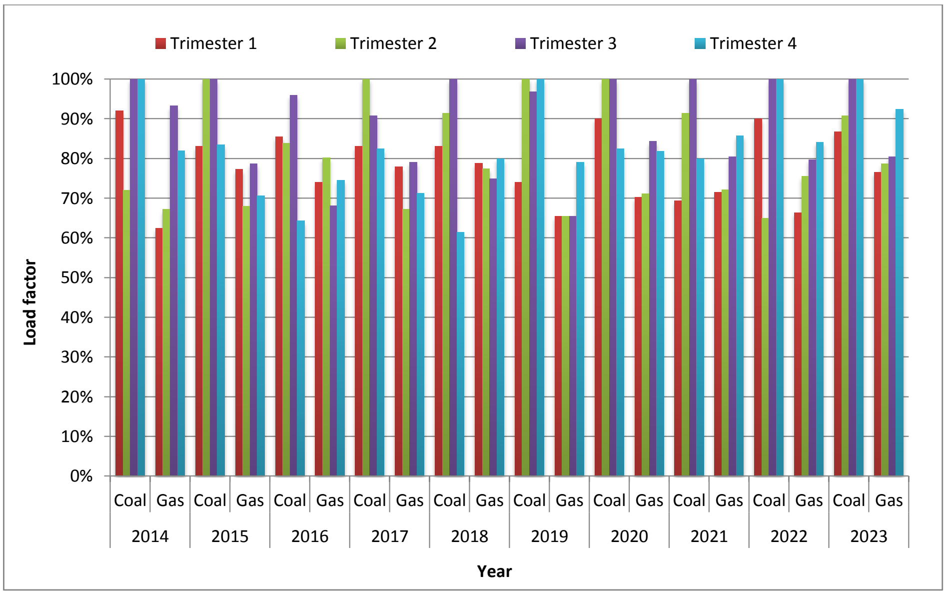


Figure 5.17: Power production solutions for intermediate Pareto curve values of emissions using integrated model (30Mton).

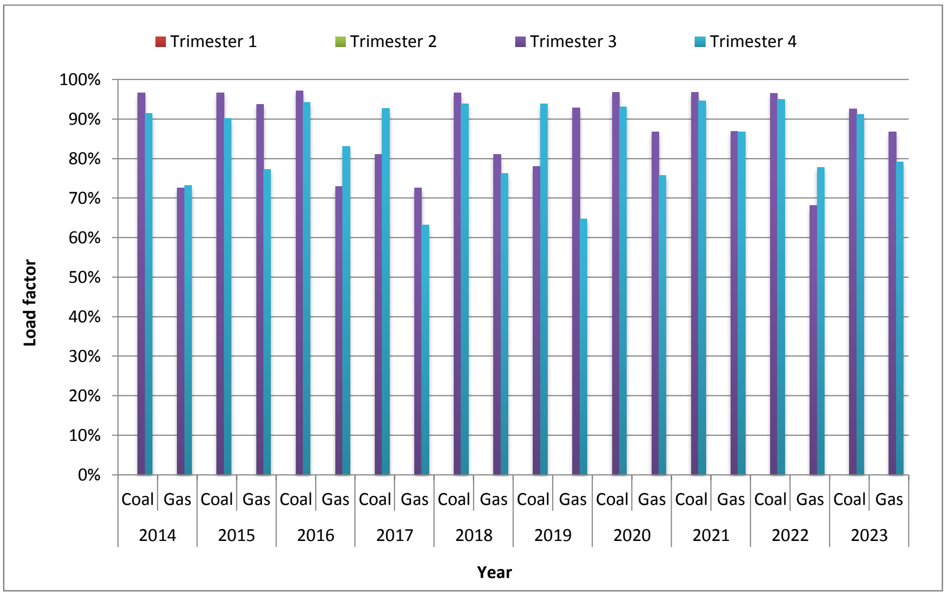
model is the earlier investment in wind power. While in the Pereira et al. (2015a) model the investment is only seen for the extreme solution of the Pareto front, in the integrated model, investment in new wind power plants starts to emerge, even that only closer to the end of planning period, for solutions closer to the minimum cost solution (see Figure 5.14). The high variability of electricity generation of these power plants, allied to the high technical constraints of thermal groups can explain this trend.

In fact, the uncertainty associated to the renewable sources, with focus on the wind, brings high challenges to the operation of the electricity system. This uncertainty is also highly related to the seasonality of each trimester of the year. Both Figures 5.18 and 5.19 show precisely this. Both coal and gas technologies have very different operating conditions. While coal power groups work as base load power plants, CCGT power groups, being more flexible can be partially used to backup, compensating the variability of RES electricity generation. Therefore, CCGT power groups tend to work as peak load power plants. Figure 5.18, shows that for the entire planning period and during all trimesters, coal power groups load factor is higher than the CCGT ones.

As referred above, seasonality along the year has a significant impact on the power systems operation. Traditionally dry seasons as summer and autumn (trimester 3 and 4 respectively) contrast with typical wet and windy seasons as winter and spring (trimester 1 and 2 respectively). Thus, because of the increase renewable sources electricity generation verified in both first and second trimester, coal and CCGT power plants electricity generation tends to be lower when comparing with the same generation power plants in the remain trimesters. On the other hand, if utilization factor is considered, as presented in Figure 5.19a, it is possible to verify that CCGT utilization factor (related to the number of operating hours) tends to be higher during higher RES availability periods, as is the case of first and second trimester. CCGT is then compensating the wind and hydropower variability, even if this means working a larger number of hours at lower load factor levels. On the other hand, with the lower availability of RES, traditional power groups tend to increase their share of electricity generation, with both higher utilization and load factors during the third and fourth trimesters. This trend is presented in Figure 5.19b, with coal and even gas power groups contributing to electricity generation only in trimester 3 and 4. Although Figure 5.19b represents an emission minimization solution, coal power output still remains relevant with investments foreseen on new and more efficient coal power plants. These ones, would be operating at both high load and utilization factors as shown in figures 5.18 and 5.19.

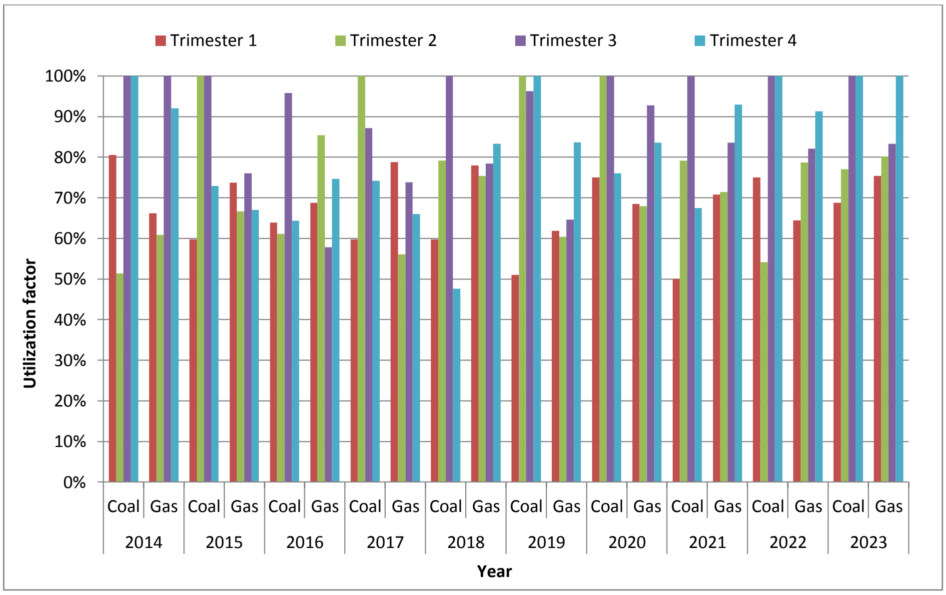


(a) Minimum cost solution

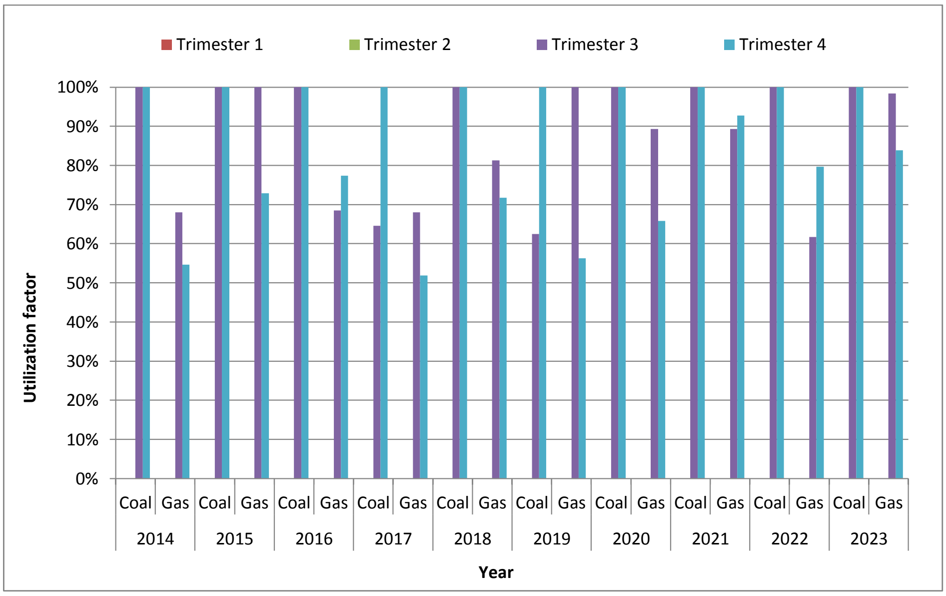


(b) Minimum emissions solution

Figure 5.18: Thermal power plants load factor



(a) Minimum cost solution



(b) Minimum emissions solution

Figure 5.19: Thermal power plants utilization factor

5.4.3 Wind power sensitivity analysis

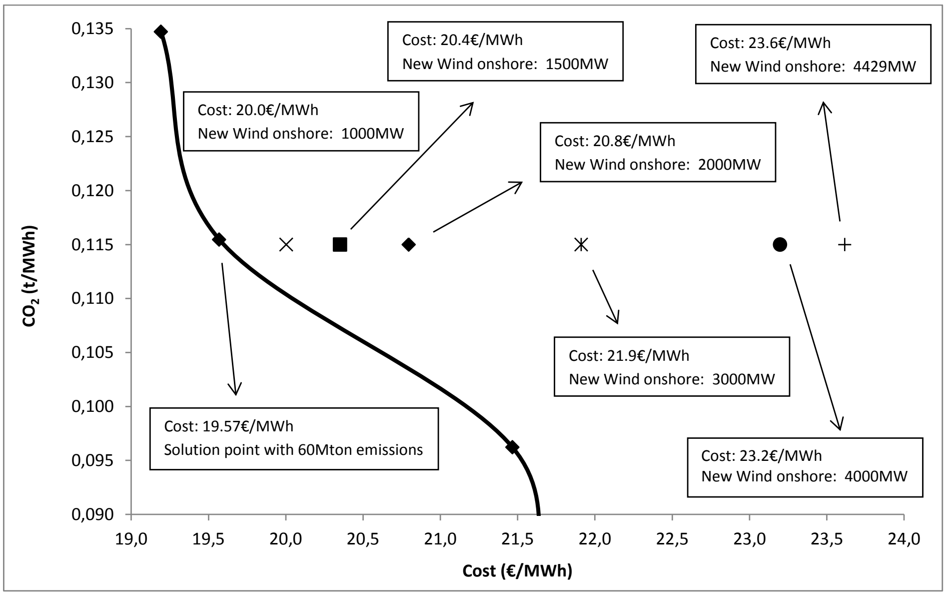
In this work, a wind sensitivity analysis is also considered for the comparison of both models. For this, solutions close to the Pareto optimal but with different shares of wind power were analysed, as these options can be relevant depending on the decision makers. Figure 5.20, represents the Pareto fronts for the two models and their sensitivity analysis. These solutions were obtained with a maximum amount of CO_2 emissions equal to 60Mton for the entire planning period. Departing from the base case, presented in Figures 5.11 and 5.15, additional constraints were added to the models imposing minimum predefined values for the new installed wind power between 1000 MW and the assumed maximum wind potential (4429MW).

For both models, the results show that an increase of the total installed wind power will mostly lead to a reduction on the investment of new run–of–river power plants, promptly compensated by the new wind power plants. Furthermore, for both models, CCGT production tends to be reduced and replaced mainly by wind and in a much less extension by coal.

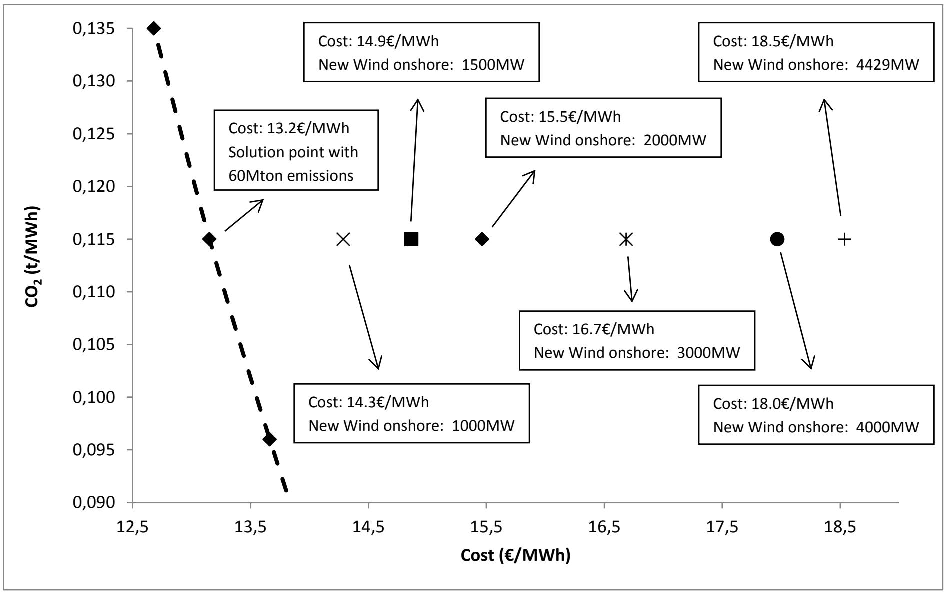
Once more, the cost obtained using the integrated model were higher then the ones obtained with the Pereira et al. (2015a) model. However, the cost differences between the base solution and each new solution constrained by minimum installed wind power, are higher for the Pereira et al. (2015a) model as seen in Table 5.2. This comes from the fact that for the integrated model, base solution already included new wind power plants. This mean that the imposed wind power constraints were less restrictive to this model then to the Pereira et al. (2015a) model.

Table 5.2: Costs increase for the different wind power solutions comparatively to the base solution

MW	Integrated model (€/MWh)	Pereira et al. (2015a) model (€/MWh)
1000	0.4	1.1
1500	0.8	1.7
2000	1.2	2.3
3000	2.3	3.5
4000	3.6	4.8
4429	4.0	5.4



(a) Integrated Model



(b) Long-term Model

Figure 5.20: Wind power sensitivity analysis

In general, these new wind power constraints lead to higher costs. However, although not being optimal solutions under an economic perspective, they can represent valuable options for the decisions makers that may assign a high importance to non–economical criteria. In fact, these new solutions contribute to the reduction of the external energy dependency and to the increase of the share of electricity production from RES.

5.5 Conclusions

This paper presents a new optimization model to analyze the generation expansion planning problem in a power system mixing wind, thermal and hydropower plants. The innovative aspect comparing with other problems for the generation expansion planning is the inclusion of electricity power generation scheduling also known as unit commitment problem, resulting in an integrated model. The adoption of a hourly time step to be considered in each year of the generation expansion problem helps on the increase reliability of the problem, in a model that allows to fully acknowledge the short-term impacts of long-term strategies, during the decision making process. A deterministic programming model was proposed, taking into account the need to reconcile economic and environmental objectives and also with focus on the impacts that an increase on the installed wind power may have on the system performance.

The analysis of results allows to verify that as the CO_2 objectives become more restrictive, in general, electricity generation from existent coal power groups tends to be replaced by CCGT ones and by the investment in new power plants, even coal power ones. This becomes necessary so the system can be able to deal with the variability and unpredictability of the RES power plants. Thus, the proposed integrated model will ensure the best generation expansion planning without disregarding the technical constraints of thermal power groups. The results also demonstrates that only for highly environmentally constrained solutions, new wind power will be added to the system. This can be explained by both the higher investment costs of wind power technology and the added difficulties of the system to deal with variable output technologies.

As coal power groups will work as base load groups while gas and hydropower groups/plants will frequently be required to work as peak load groups/plants, the increase of RES of variable output such as wind or run-of-river plants will have a major impact on the gas power groups operating conditions. In fact, the results show that the increasing variability and unpredictability of RES generation will frequently originate periods of operation at low load levels and also to lower utilization factor periods. A high RES reliance will also turn the system more sensitivity to the resources seasonality. Higher RES resources availabilities during winter and spring seasons leads to lower load and utilization factors of thermal power groups, contrasting with the higher load and utilization factors during summer and autumn seasons.

Finally, the usefulness of the integrated model is demonstrated for the analysis of high wind power scenarios. In fact, imposing new wind power to the system may not lead to the optimal solution under an economic perspective, however, may be interesting from the strategic decision makers' perspective.

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Chapter 6

A userfriendly tool for electricity systems analysis

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ABSTRACT

Optimization models to support energy decision making, with focus on electricity generation, have been used since the 70's. While these models were initially mainly focused in the economic aspects, nowadays models take into consideration a new paradigm of electricity power generation, due to the increase of fossil fuel prices along with increasing environmental concerns. While several decision support tools for the energy sector are available, most of them require considerable experience and programming skills from the users. This work intends to present and detail a new user-friendly tool, coined as ESAM, which is supported by four different (optimization) models. One model for the generation expansion planning (GEP), one model for unit commitment (scheduling problem) process, one model representing a simplified approach of the scheduling problem, and lastly, one model that combines the generation expansion problem with the scheduling problem (integrated problem). The goal of ESAM is to provide an interface between users and the optimization models translated in GAMS codes, allowing the use of these optimization models

in a easier and more intuitive way. Therefore, the proposed tool aims to facilitate data input, simulation of the electricity systems and results output, promoting the effective dissemination of the models.

Keywords: Generation expansion planning, Unit commitment, Graphical tool.

6.1 Introduction

Society is nowadays more aware concerning worldwide climate change threats. These society concerns, together with the finite availability of fuel fossil resources (and consequently their increasing price trend) are in focus and have a particular impact in strategic energy decisions. Additionally, environmentally negative impacts of traditional resources, like coal and gas, in electricity power generation have been promoting RES power technologies. These new concerns are leading to a change on the paradigm of electricity power generation, making the use of RES for electricity production a key issue.

In spite of the numerous advantages associated with the use of RES, its inclusion creates complex planning challenges to both the strategic decision making and the operation of the electricity power generation system (unit commitment problem). Characterized by its variable output and limited predictability, RES availability remains difficult to forecast, leading to adverse consequences to the normal operation of traditional electricity power plants generation. Problems such as insufficient regulating and reserve power (Ummels et al., 2007), increase ramping requirements of traditional power plants (Albadi and El-Saadany, 2010), or traditional power plants low level operation (Pereira et al., 2014) are usually associated to RES variability, with a high contribution from wind power generation.

Current changes and difficulties in the energy sector planning, in particular in the electricity generation, demands for the use of strategic planning tools. The objective of this work is to present a new user-friendly application (coined as ESAM) that consists in a tool considering a graphical interface between new optimization models for electricity power planning and an optimization solver, providing to the decision makers a strategic planning tool.

This paper is organized as follows. First, section 6.2 presents a survey of the most used energy planning computer tools. In section 6.3, a detailed description of the ESAM tool is presented. Finally, conclusions are stated in the last section, section 6.4.

6.2 Survey on computational tools for energy planning

Energy planning problems complexity has increased over the years due to the increase on available technologies, networks size, and environments concerns. Decision makers are now supported by complex mathematical software. According to Foley et al. (2010), electricity systems models are tools used by electricity analysts to manage and plan the electricity system, to trade electricity, and for generation expansion planning purposes. Author also enhance that electricity system's modeling is now more complex, requiring new technics due to technological advances and environment concerns. While a huge variety software is available, each one has specific characteristics and are applied in different ways and to different planning problems. Models like MARKAL and TIMES (ETSAP, 1976), MESSAGE (IIASA, 1980), LEAP (Heaps, 2012), HOMER (1992), WILMAR Planning Tool (WILMAR, 2006), EnergyPLAN (1999), PLEXOS (1999), among others are largely used and well documented over literature. For example, MARKAL is a mathematical model of the energy system that *"computes energy balances at all levels of an energy system: primary resources, secondary fuels, final energy, and energy services"* (IEA, 2009). It was developed in a cooperative multinational project by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA) that started in 1978 and whose main objective is to obtain energy services at minimum global costs. Both investment, operating, and primary energy supply decisions are considered by the model. More recently, TIMES (integrated MARKAL-EFOM System) model generator was developed and uses long-term energy scenarios to conduct in-depth energy and environmental analysis. It combines two different, but complementary, systematic approaches to energy modeling, which consists in a technical engineering approach and an economic approach. TIMES is a rich technology, bottom-up model generator, which uses linear-programming to produce a least-cost energy system over medium to long-term time horizons (IEA, 2009). TIMES code is written in GAMS (2011), which is a commercial high-level modeling system for mathematical programming (Connolly et al., 2010).

MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental impact), was developed by the International Institute for Applied Systems Analysis (IIASA) in Austria since 1980 (Connolly et al., 2010). It is a systems engineering optimization model used for medium to long-term energy system planning, energy policy analysis, and scenario development (IIASA, 1980). According to Connolly et al. (2010), the software uses a 5 or 10 years time step, taking into consideration thermal generation, renewable, and storage/conversion transport technologies, allowing costs to be simulated.

LEAP (Long range Energy Alternatives Planning system), is a software for energy policy analysis and climate change mitigation assessment, developed at the Stockholm Environment Institute in 1980. It is an integrated modeling tool that can be used to track energy consumption, production and resource extraction in all sectors of an economy (Connolly et al., 2010; Heaps, 2012). LEAP model can be considered as a medium to long-term model and most of it analysis uses annual time step.

The EnergyPLAN model, developed and maintained by the Sustainable Energy Planning Research Group at Aalborg University since 1999, allows to study the operation of national systems on an hourly basis, contrary to models like MARKAL, TIMES and MESSAGE that use for planning medium to long-term energy systems, developing scenarios for national or global regions and taking into account climate change policies (EnergyPLAN, 1999). EnergyPLAN operation analysis includes electricity, heating, cooling, industry, and transport sectors. Therefore, different thermal, renewable storage/conversion, transports, and costs are considered. Programmed in Delphi Pascal, the model has a user-friendly interface and is freeware (EnergyPLAN, 1999; Connolly et al., 2010). According to Connolly et al., 2010, pg. 1068, EnergyPLAN *"optimises the operation of a given system as opposed to tools which optimise the investment in the system"*.

Another tool, largely used and well documented in literature, is PLEXOS Integrated Energy Model. Developed by Energy Exemplar company and first released in 2000, PLEXOS is an energy market simulation software that uses cutting-edge mathematical programming and stochastic optimization techniques (PLEXOS, 1999). With a comprehensive graphical interface, PLEXOS is an easy to use software with a set of different applications such as production cost simulation, capacity expansion planning, renewable generation integration analysis, and operational planning with stochastic optimization.

In addition to the models described above, a large set of different models with a large diversity of energy analysis applications can be found in the literature. A more detailed survey over the existent tools for energy analysis can be seen in Connolly et al. (2010).

In a general way, optimization models without graphical support are not user-friendly. Additionally, most of them are focused exclusively on a specific approach like generation expansion or scheduling, neglecting, for example, the integration of both approaches. Therefore, the demand for a new tool is relevant and appropriated. This work presents a new user-friendly application (ESAM) that consists of new optimization models for electricity power planning, based on a multi-periodic approach combining optimization models for long-term capacity expansion with models for the unit commitment process, based on short-term optimization of the available resources. ESAM gives access to a set of optimization models, previously described and translated in GAMS, in a more intuitive and easier way. The set of models includes the model for the strategic electricity power planning for long-term capacity expansion (generation expansion problem), the model for unit commitment process, the model based on short-term optimization of the available resources (scheduling problem), the model representing a simplified approach of the scheduling problem, and an integrated model that combines the generation expansion problem with the scheduling problem (integrated problem). All models comprise a set of different fossil fuel power groups, mostly coal and gas, two different types of hydropower plants (large hydropower plants with reservoir and the run–of–river power plants), pumping power plants, and wind power plants. However, for simplification propose, no individual wind and hydropower plants are considered. Thus, all the individual wind power and hydropower plants were aggregated and two sets, one for wind power and other for hydropower, are considered. All models have as objective function the cost minimization, however, for both GEP and integrated problem, besides costs minimization, CO_2 emission minimization is considered, transforming these problems into bi-objective problems.

6.3 The ESAM tool and models

In the following subsections, a detailed description of the ESAM tool is presented. The tool was developed in Visual Basic, using the Microsoft Visual Studio environment. Figure 6.1 provides the main menu, from which access to all models that compose the application can be gained. In the main menu, information about the ESAM tool, as well as all contacts, can be obtained. The ESAM tool also provides (several) test cases that can be loaded by selecting "File", "Add","Example case study". This example loads the Portuguese case study, allowing user to consider some already defined options. The implemented models are described in the following subsection.

6.3.1 Generation expansion problem

By definition, the generation expansion planning problem (GEP) is the problem of *"determining WHAT, WHEN, and WHERE new generation units should be installed over a planning horizon to satisfy the expected energy demand"*[Meza et al., 2009, pg. 1086]. This section is used to describe, in detail, the ESAM module where the GEP model presented in Pereira et al. (2015a) is implemented. This module can be accessed by selecting the option "File" in the main menu (Figure 6.1). The "New", "Generation Expansion Problem" subitems will open a new window as show in Figure 6.2.

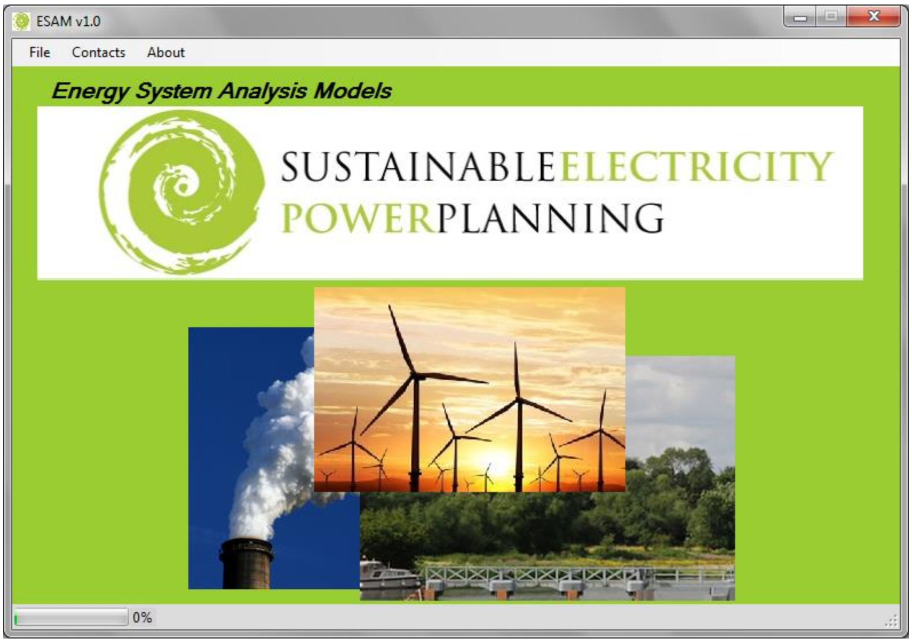


Figure 6.1: ESAM tool (Main Menu).

The first window is composed by three main tabs named "Model Elements Id", "Costs & Units Capacity", and "Electricity Demand & SRP[1]" as can be seen in Figure 6.2. In the first one, the user will be able to choose the horizon time for his problem, the name of the set of existent (installed) power plants, as well as the name of the new (to be installed) power plants to be considered in the optimization process. The "units validation" button provides an update/refresh of the model.

The next tab, named "Costs & Units Capacity", is where most of the input data concerning power plants can be changed by the user. Three new sub-tabs, named "Power Units", "General Settings", and "Overall View", are considered as can be seen in Figure 6.3.

In this first sub-tab, "Power Units" (Figure 6.3), the user is allowed to define the input data related to the modular capacity (group capacity) of new (to be installed) thermal power groups, renewable wind and hydropower units potential (maximum capacity allowed to install for each considered technology), large hydropower plants (dams) inflows with respective reservoir levels, and some others considerations such as, minimum renewable production, pumping costs,

[1]Special Regime Producers (SRP) - For this work, SRP is assumed to include all renewable power plants except wind and largehydro power plants.

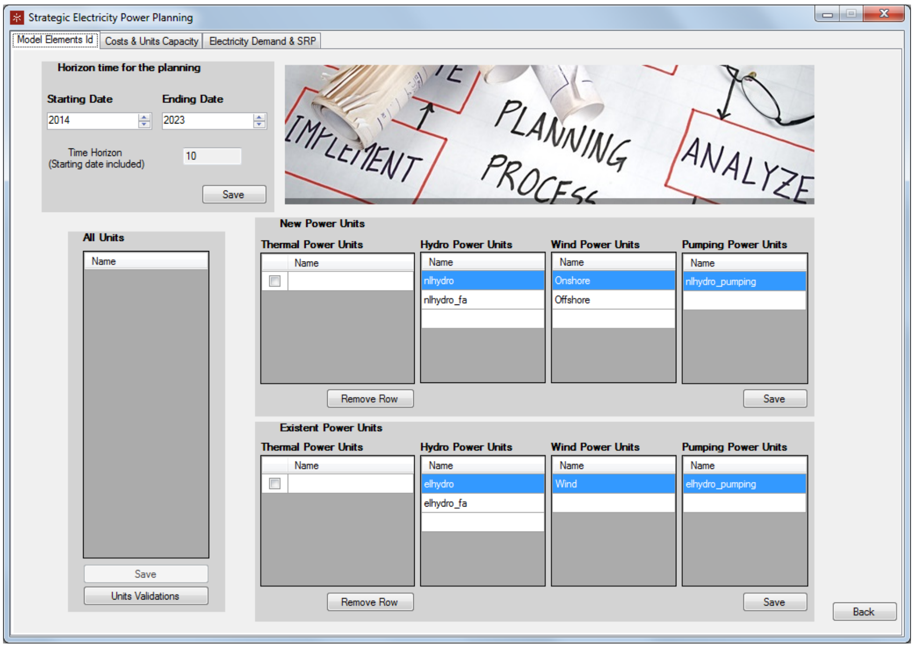


Figure 6.2: ESAM tool (GEP)

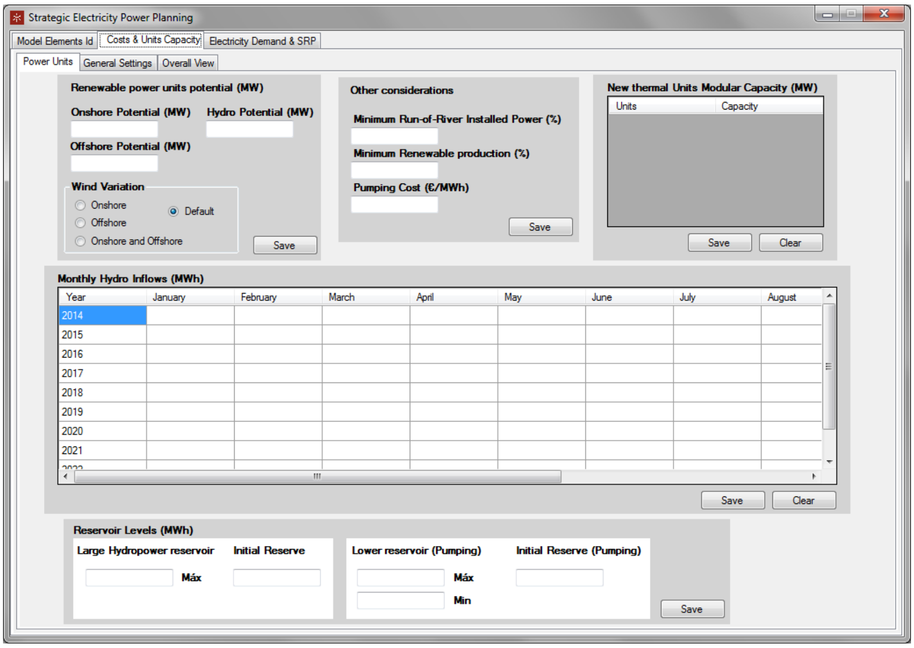


Figure 6.3: ESAM tool “Costs & Units Capacity” tab/“Power units” sub-tab

and minimum run-of-river installed power. ESAM tool also allows users to enforce the model to install a specific value of wind power capacity (see top left form in Figure 6.3). Besides that, the model also allows to consider a minimum capacity (to be installed) of run-of-river power plants, that can be used to compensate the (geographical and physical) limitations in installing large hydropower plants (dams).

In the "General Settings" sub-tab, shown in Figure 6.4, input data for the yearly peak load, power plants monthly availability, new power plants lifetime, special regime producers installed power, reference margin, and considerations like emissions allowance cost and discount rate can be updated by the user. In this sub-tab, users are also allowed to obtain costs minimization having into account a specific amount of CO_2 emissions (see top left form in Figure 6.4). The reference margin (RM), given by equation (6.3.1) (see (Ferreira, 2008)), can be computed pressing the "Reference margin computation" button. A new window, shown in Figure 6.5, is used to introduce the corresponding values, where the example provided by the ESAM module can be tried out by pressing the button "Data Example".

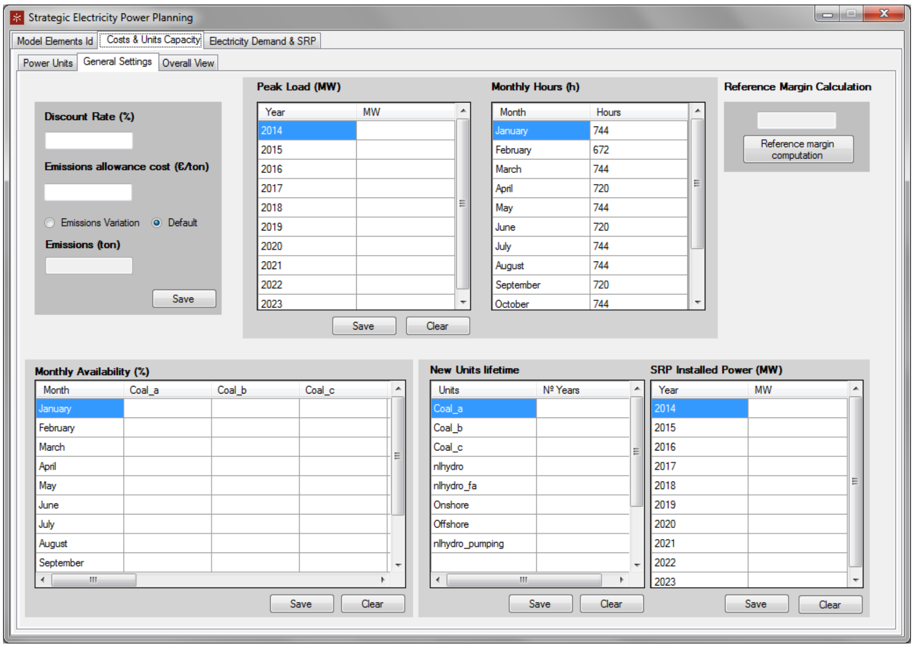


Figure 6.4: ESAM tool (GEP) "Costs & Units Capacity"/"General Settings" sub-tab

$$RM = \frac{(Reliable \quad available \quad capacity - Peak \quad Load)}{System \quad Capacity} \tag{6.3.1}$$

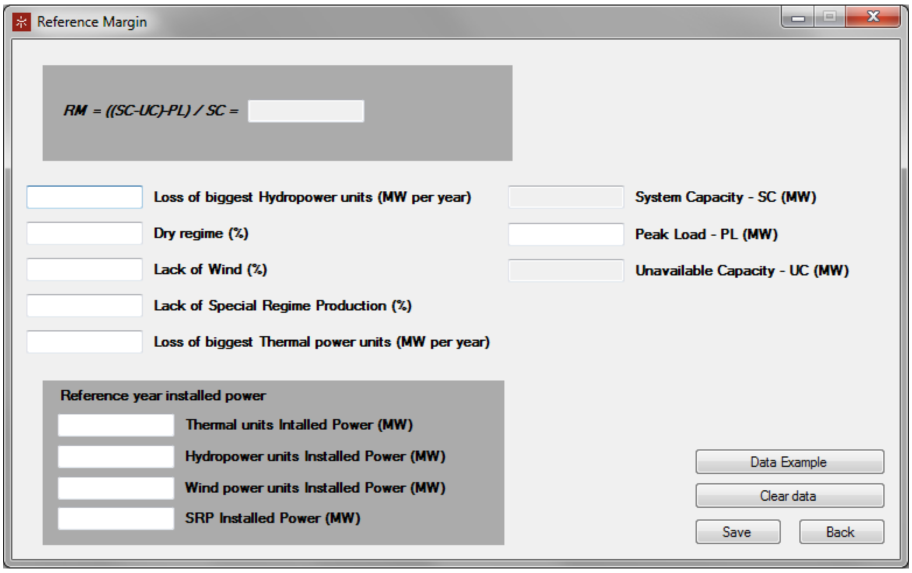


Figure 6.5: Reference Margin window calculation

In the last sub-tab, "Overall View", shown in Figure 6.6, the user is able to insert the data related to the investment and fixed operation & maintenance costs of new power plants, variable operation & maintenance costs, CO_2 emissions costs, fuel cost of all power units, and the power plants installed capacity of existent power plants.

The last "Electricity Demand & SRP" main tab is where the user can update the monthly and annual electricity demand, and also the expected SRP production. The data is inserted in the form presented in Figure 6.7.

After saving all the data that refer to the model, the user can run the model by pressing the button "Run Gams", under the same tab. After the simulation the results are saved in an Excel (2015) file (.xlsx) named generation_expansion_problem and located in GAMS project directory (typically in the $c:\backslash Documents\backslash gamsdir\backslash projdir$). Thus, user will be able to freely analyze all the obtained results. Future versions of ESAM module will internally present and analyze the results.

6.3.2 Scheduling Problem

Scientific literature provides a huge variety of definitions for the unit commitment (UC) problem. According to Norouzi et al. (2014), the goal of implementing an UC problem is to optimize energy sources, being the load demand supplied

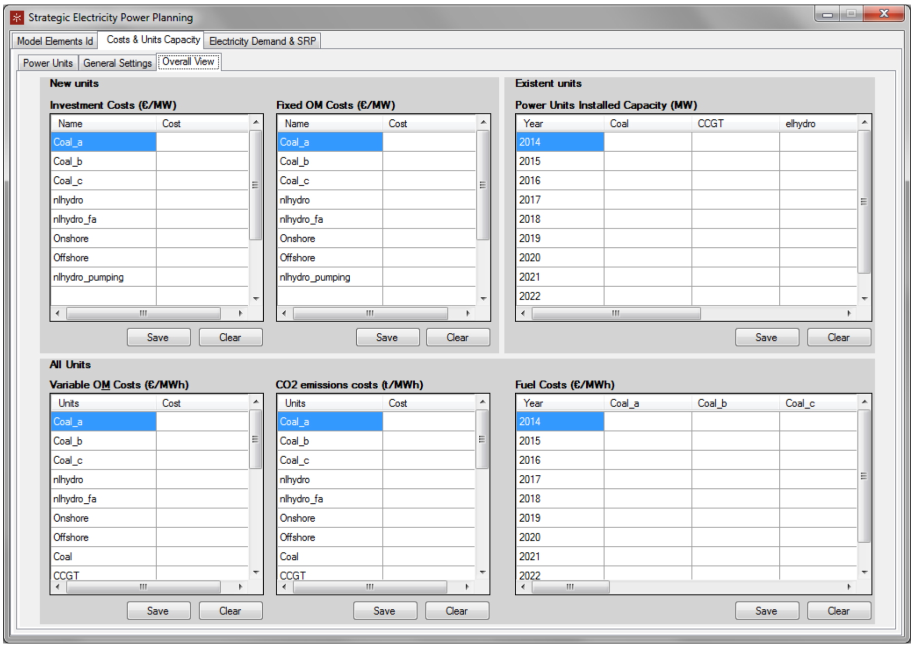


Figure 6.6: ESAM tool (GEP) “Costs & Units Capacity”/“Overall view” sub-tab

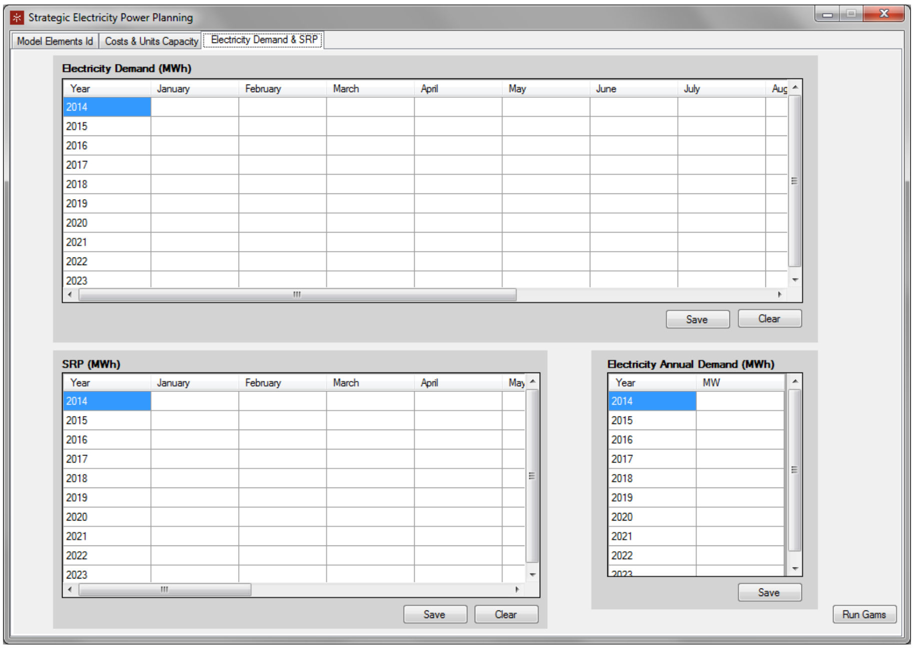


Figure 6.7: ESAM tool “Electricity Demand & SRP” tab

at the lowest cost. Delarue et al. (2013) refers to the UC problem as the process of schedule the power plants to meet the demand fluctuation. For Catalão et al. (2008, pg. 3), "*short-term scheduling of thermal units is defined as the task of establishing the minimum fuel cost for the hourly generation schedule of the thermal power plants during a time horizon of 1 day up to 1 week, satisfying the demand of electrical energy and the considered constraints*". In line with this, Senjyu et al. (2003) defined UC problem as the problem of defining the proper on/off state of all power plants of the system in each time interval, minimizing costs, and meeting the demand forecasts and spinning reserve.

Latterly, the increase penetration of RES on the electricity system, and therefore their impacts, are a major concern for the electricity system managers. Thus, new challenges for the electricity system managers are expected to emerge. The use of ESAM tool can therefore be an important support to assess the impact that different levels of renewables integration may have on the operation and management of the electricity system, along with dealing with the commissioning of the involved power plants.

In the following subsections, a detailed description of both extended and simplified approaches of scheduling problem is presented.

Scheduling problem – Extended approach

The Extended approach module can be accessed by selecting the option "File", "New", and then "Scheduling Problem" from the main menu window (see Figure 6.1). A new window, as the one shown in Figure 6.8, with three main tabs named: "Model Elements Id", "Costs & Units Capacity", and "Electricity Demand & SRP", will appear, allowing user to insert the data and to select all possible model options.

Thermal groups names, to be considered in the model, are inserted in the first main tab. This first version of ESAM only considers gas and coal thermal power groups. As RES power plants are aggregated, they are already pre-defined in the model. In the same tab, users are also able to define the model time horizon (defined in hourly steps of 24 or 168 hours) and the emissions allowance costs.

The second main tab, named "Costs & Units Capacity", addresses the power plants main characteristics. This tab is composed by two sub-tabs named "Thermal Power Units" and "Renewable Units", as can be seen in Figure 6.9. The first main issue is the model type selection where the extended model or a simplified approach can be selected. The simplified approach description is postponed to subsection 6.3.2. Considering the extended model, costs, capacities,

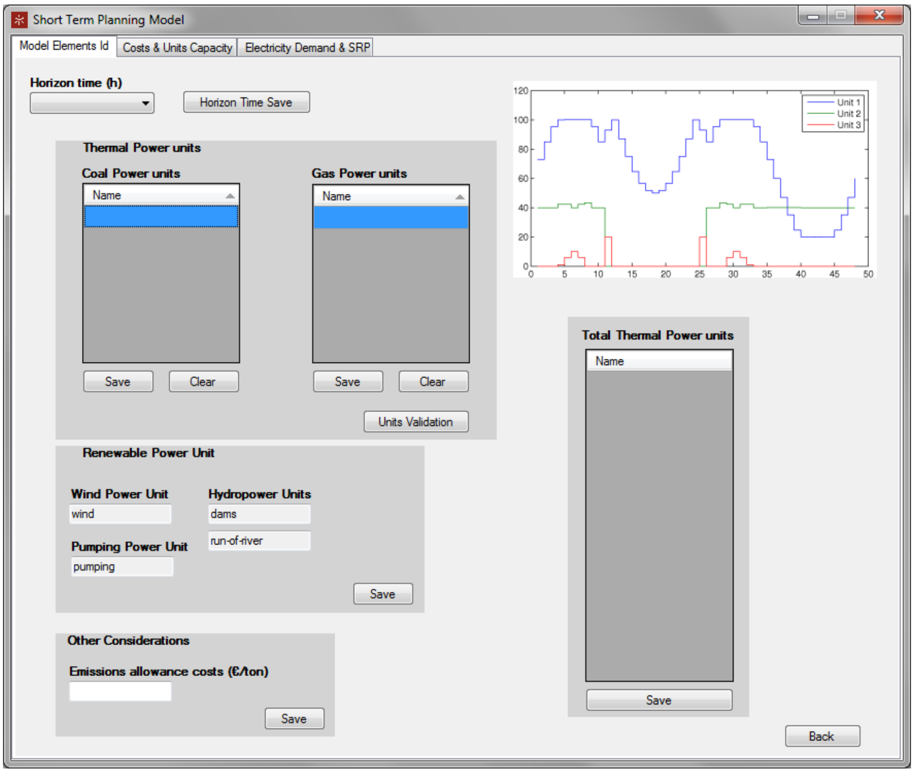


Figure 6.8: ESAM tool (Scheduling Problem)

and some other technical characteristic of thermal power groups are addressed in the “Costs & Units Capacity” first sub-tab (Figure 6.9). Concerning costs and groups capacity of coal and gas thermal power groups, user is able to insert the maximum and minimum capacity, and fuel, variable operation and maintenance (O&M) costs. Technical aspects such as the minimum up and down time, and the technical power groups cold and hot startup time can also be considered. Additionally, shutdown, hot and cold startup costs can be considered. The CO_2 emissions released by power groups as well as typical security considerations, as the case of the spin reserve, are also considered. Finally, the ESAM module also allows users to consider ramps settings. These settings can be inserted in the ramps window, obtained by pressing the button “Ramps”, as shown in Figure 6.10. In this new window, users are able to insert all data related to the up, down, startup, and shutdown ramps capacity.

Sub-tab “Renewable Units”, as shown in Figure 6.11, regards to renewable power plants, where its main characteristics can be considered. These characteristics encompasses the variable operation & maintenance costs, power plants capacity, wind and run-of-river plants hourly availability, and large hydropower plants inflows. Regarding large

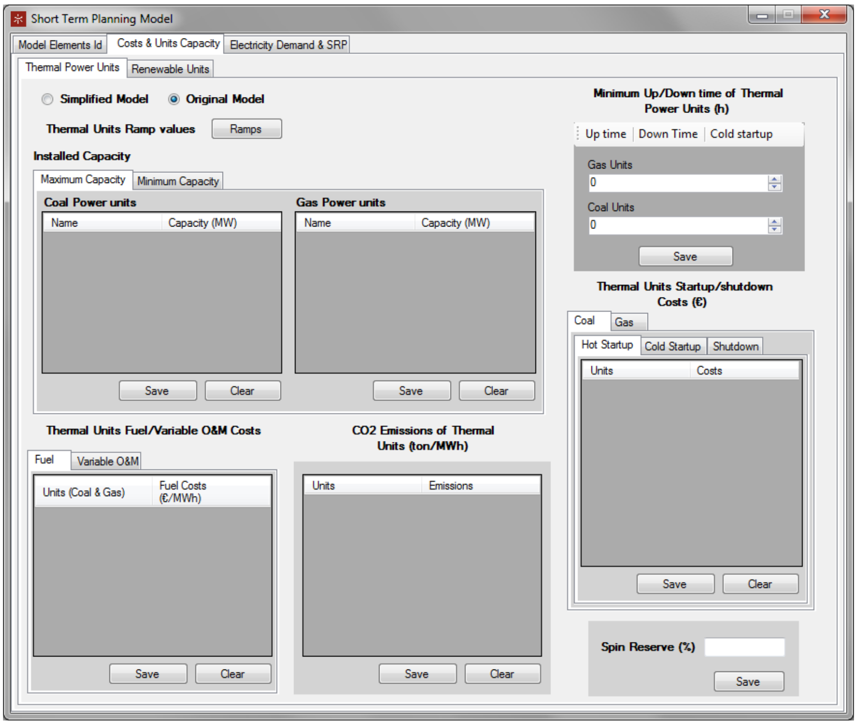


Figure 6.9: ESAM tool “Costs & Units Capacity” tab/“Thermal power units” sub-tab

hydropower plants, reservoir levels as well as pumping costs can be considered and dimensioned. In this sub-tab, the user is also allowed to specify a value for CO_2 emissions over which want to minimize the overall system costs (see top right form in Figure 6.11).

The last main tab, named “Electricity Demand & SRP”, regards to the expected demand and special regime producers generation. Here the user is able to insert the expected hourly demand to be met, as well as the expected SRP generation. Figure 6.12 is representative of this tab section. After inserting and saving all data, optimization results are obtained by running the model, which can be achieved pressing the button “Run Gams”. Once again, results will be saved in an Excel file (.xlsx) named scheduling_problem and located in the GAMS project directory (typically in the $c : \backslash Documents \backslash gamsdir \backslash projdir$).

Simplified approach

Usually, the complexity associated to the scheduling problems, due to the large amount of power plants/groups and time horizon considered, leads to complex mixed integer programming problems, which are computationally expensive

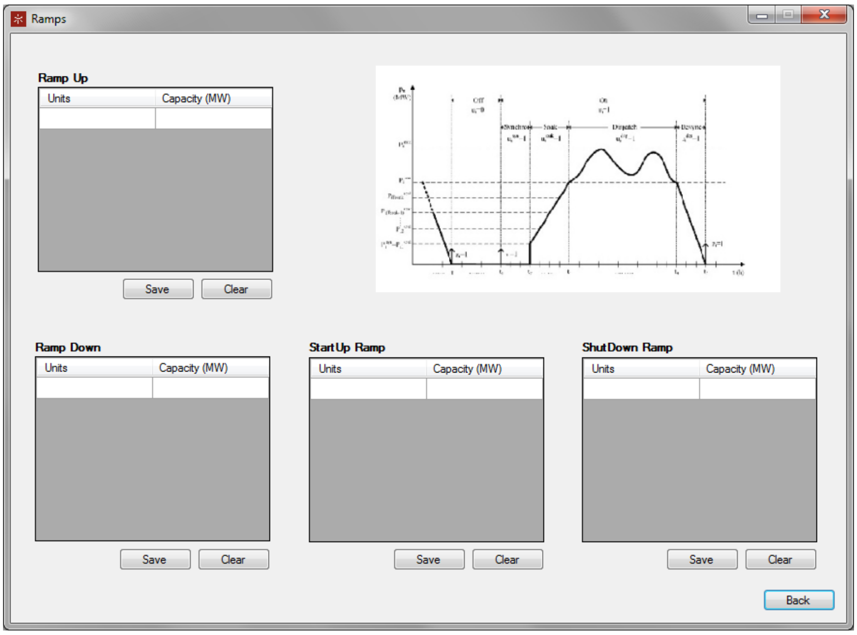


Figure 6.10: Ramps considerations

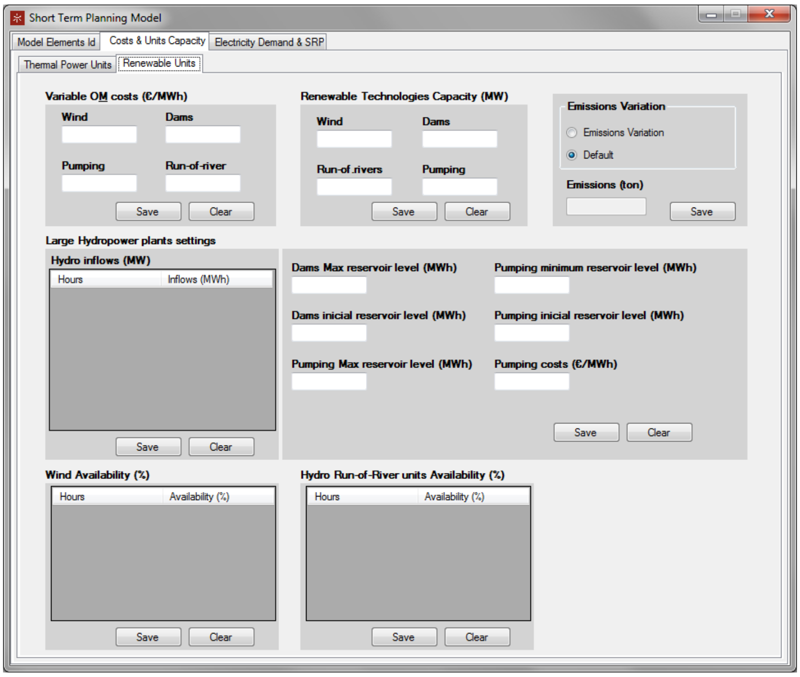


Figure 6.11: ESAM tool “Costs & Units Capacity” tab/“Renewable Units” sub-tab

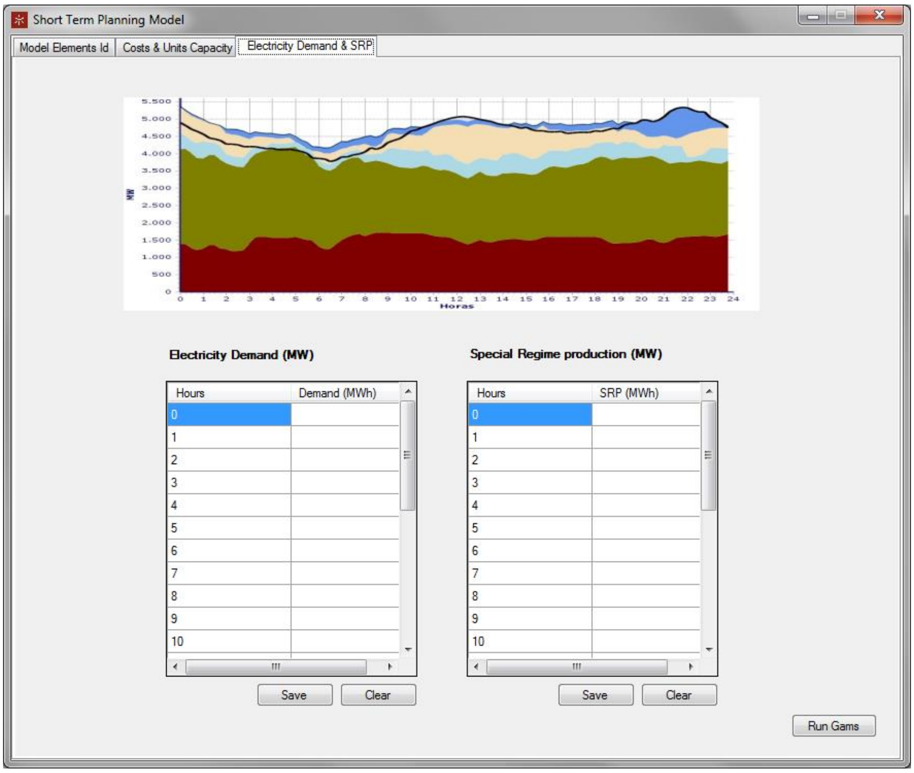


Figure 6.12: Schedule problem "Electricity Demand & SRP" tab.

to solve. However, simplified approaches of existent models can be used to obtain numerical results that, despite of not being optimal, give satisfactory accuracy. This simplified model allows users to try a large number of different scenarios in a reasonable computing time (Pereira et al., 2015b).

The simplified model can be accessed in the sub-tab "Thermal Power Units" under tab "Costs & Units Capacity" of the schedule problem section, by selecting the option "Simplified Model" (see Figure 6.13). The differences between both models are focused on the thermal power groups. The simplified approach does not consider in the model the minimum up/downtime and the hot/cold startups and shutdown costs. The simplified model considers ramp options by imposing a maximum variation of power production between two consecutive periods of time fixed at 30%. However, in order to mitigate the changes when comparing with the extended approach, the simplified approach considers the typical fuel and CO_2 costs quadratic curves. These changes in the model, lead to a non-linear programming problem without integer variables (see (Pereira et al., 2015b)), which results in an optimization problem requiring less computational effort to be solved. Figure 6.13 presents the simplified approach window. In this new window, user is allowed to select quadratic curves coefficients. Moreover, the user is allowed to opt between choosing the default (internal coded) quadratic curves coefficients or select their own coefficients. This can be seen in Figure 6.14.

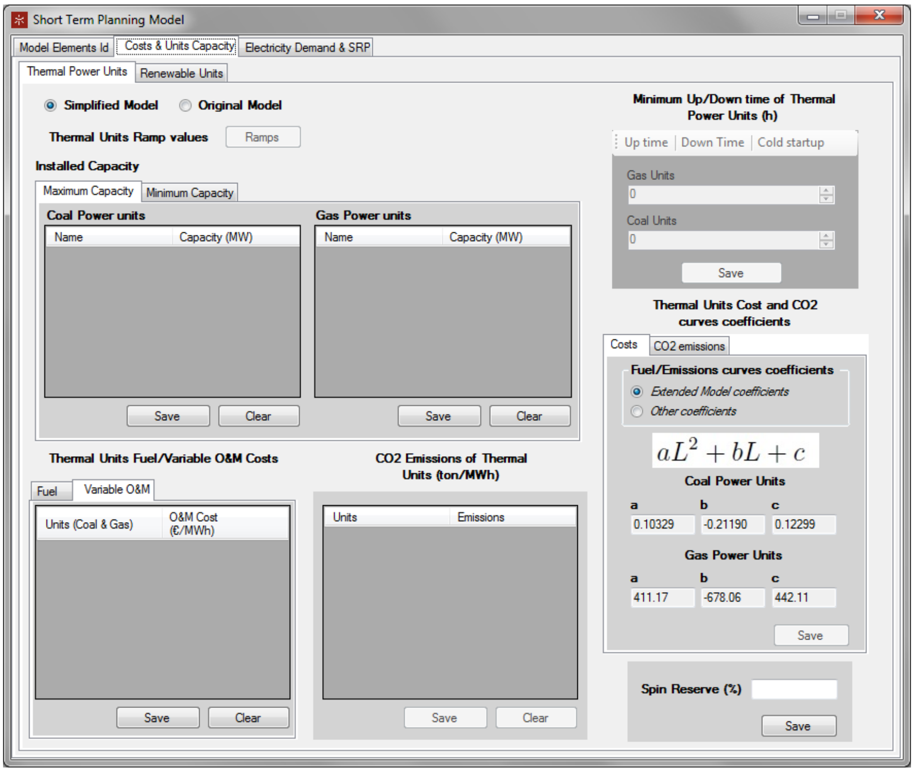


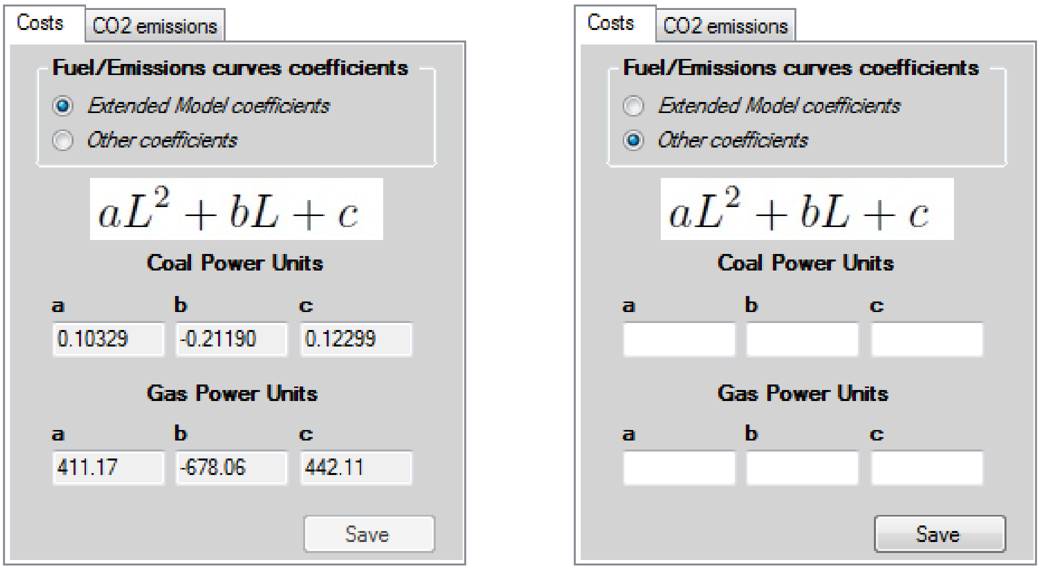
Figure 6.13: ESAM tool "Costs & Units Capacity" tab/"Thermal power units" sub-tab (Simplified approach)

The remaining model parameters and settings remains as in the extended model and results are saved in an Excel file (.xlsx) named simplified_approach and located in the GAMS project directory (typically in the $c:\backslash Documents\backslash gamsdir\backslash projdir$).

6.3.3 Integrated Problem

The development of optimization models based on a multi-periodic approach, which combine models for long-term capacity expansion with short-term models for the unit commitment process seems to be the next logical step. See Zhang et al. (2013) and Pereira et al. (2015c) for two works where such approach has already been proposed.

Following the model proposed in Pereira et al. (2015c) the ESAM module implements an integrated model that can be used by selecting, in main menu window, the menu "File", "New", "Integrated Problem". A new window, shown



(a) Fuel and CO_2 coefficients curves (ESAM suggestion)

(b) Fuel and CO_2 coefficients curves (User choice)

Figure 6.14: Fuel and CO_2 coefficients curves data (Schedule Problem - Simplified approach)

in Figure 6.15, will emerge. As shown in Figure 6.15 and, like for the previous model main window, the "Integrated Problem" provides three main tabs named "Model Elements Id", "Costs & Units Capacity", and "Electricity Demand & SRP".

In the first main tab, named "Model Elements Id", the user is able to select the generation expansion planning time horizon as well as the time horizon for the scheduling problem. In the first case, a yearly time step is used while for the scheduling problem a hourly step of 24 and 168 hours is considered. This main tab allows user to specify existent and new thermal power plants to be used in the model, by inserting their name into the provided forms.

The second main tab ("Costs & Units Capacity") provides three additional sub-tabs allowing user to insert the main input data concerning costs and technical characteristics of all power plants/groups considered in the model. These new sub-tabs are named "Thermal Power Units", "Renewable Units", and "General Settings", as can be observed in Figure 6.16. Dedicated to thermal groups, the "Thermal Power Units" sub-tab gives user access to more three sub-tabs. These tabs are, "Investment/O&M Costs", 'Installed Power", and "Fuel/Emissions costs & General settings". In the "Investment/O&M Costs" tab (Figure 6.16), the user is able to provide the investment and fixed O&M costs of the new thermal groups, and also the variable O&M costs of both new and existent thermal power groups. In the "Installed

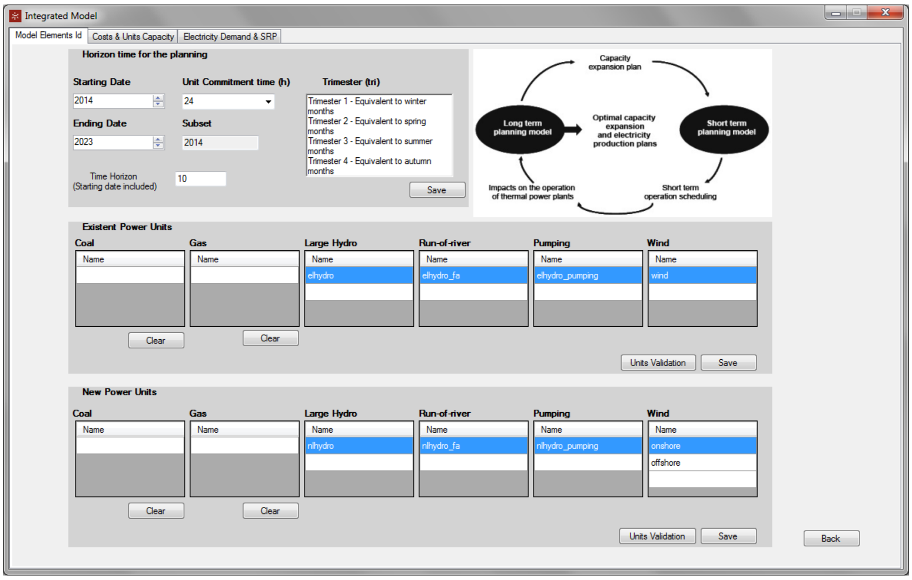


Figure 6.15: ESAM tool (Integrated Problem)

Power" tab (Figure 6.17), the user is allowed to define the power capacity of existent thermal power groups as well as the capacity of the future thermal power groups to be considering in the strategic expansion planning. Finally, the "Fuel/Emissions costs & General settings" tab (Figure 6.18) allows user to define the lifetime of the new thermal power groups, the fuel cost in ($€/m^3$) of gas power groups and the fuel and emissions curves costs coefficients of both coal and gas power groups. Note that only gas power groups fuel costs are considered because, contrary to coal groups, gas fuel curve consumption is represented in m^3/mwh and for costs minimization propose, conversion to € is require. As in the extended model, quadratic cost curves coefficients may be user specified. By default the coefficients used in Pereira et al. (2015c) are taken. Figure 6.19 shows how each possibility can be selected.

The second tab of "Costs & Units Capacity" main tab is dedicated to the renewable power plants ("Renewable Units"), which gives access to two additional sub-tabs named "Investment/O&M Costs" (Figure 6.20a) and 'Installed Power" (Figure 6.20b). In "Investment/O&M Costs" sub-tab, the user provides investment and fixed O&M costs of the new (to be installed) large hydro, run-of-river, pumping, and wind power plants. Variable O&M costs, for these new and existent (installed) power plants types, can also be provided. In the "Installed Power" sub-tab, user can define the renewable power plants lifetime, the installed capacity, the wind and hydro potential, and the SRP installed capacity. As in the generation expansion problem, a specific value for wind power potential can be defined by the user, enforcing the model to install this specific wind power capacity (see bottom right form in Figure 6.20b).

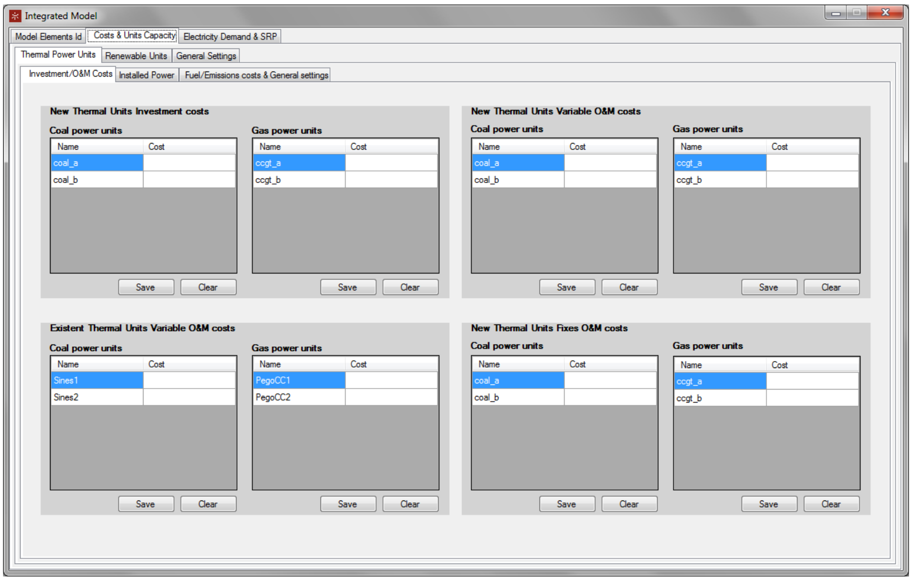


Figure 6.16: ESAM tool “Costs & Units Capacity” sub-tabs

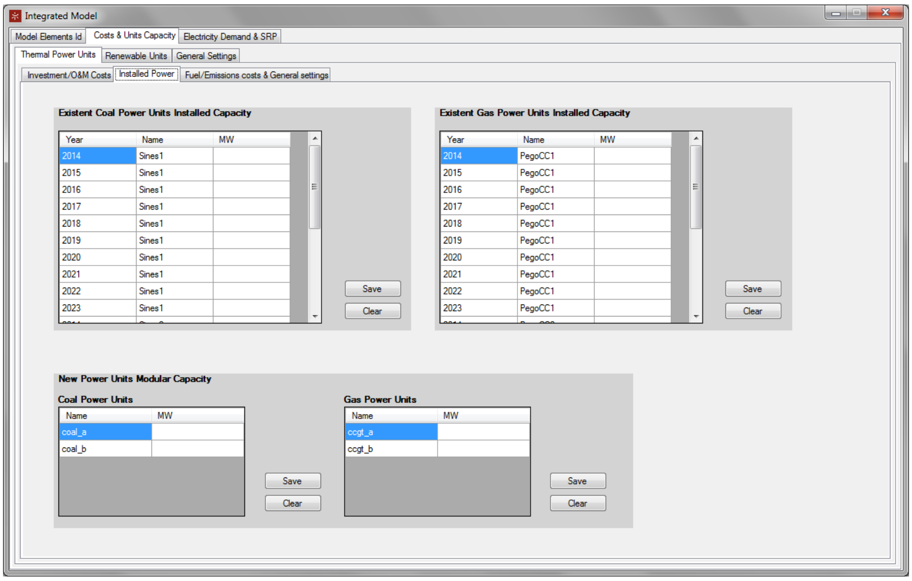


Figure 6.17: Integrated problem “Installed Power” tab (Thermal Units).

The “General Settings” (Figure 6.21) sub-tab, accessed through the “Costs & Units Capacity” main tab, allows the user to specify some additional models parameters. In this sub-tab, the user is allowed to define both wind

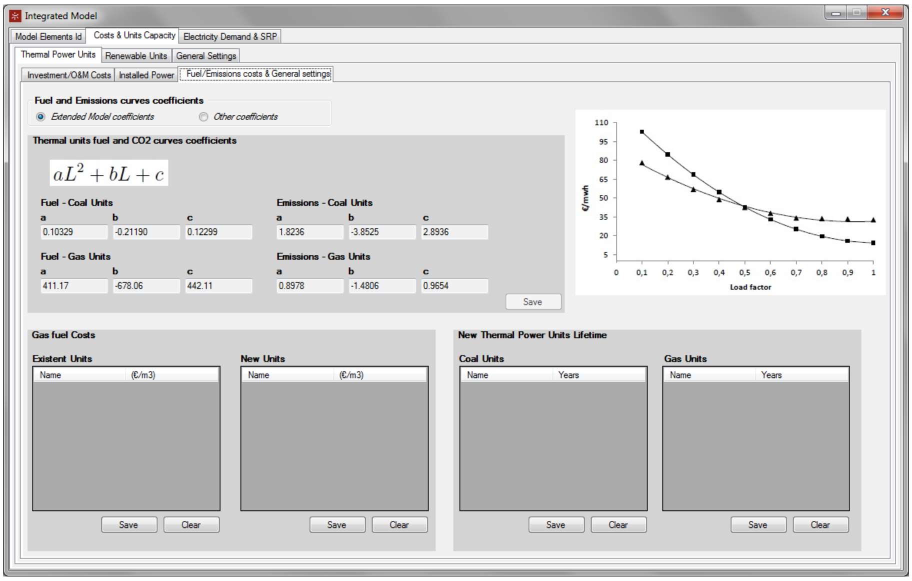
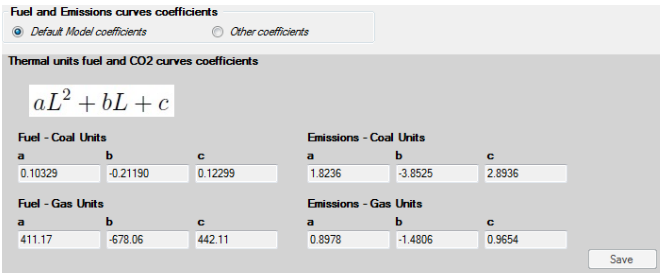
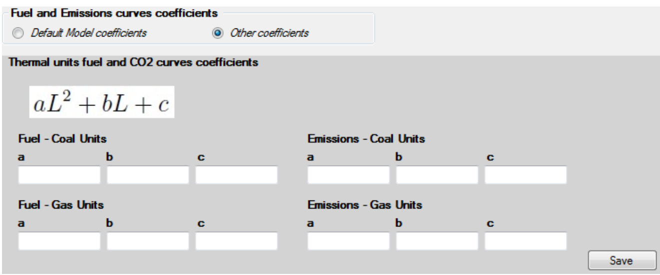


Figure 6.18: Integrated problem “Fuel/Emissions costs & General settings” tab (Thermal Units).

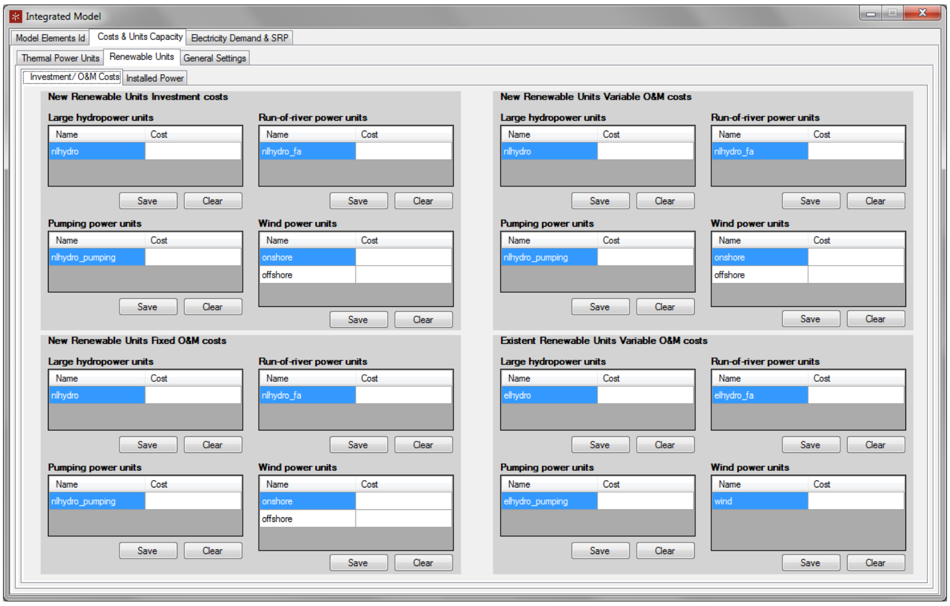


(a) Fuel and CO_2 coefficients curves (ESAM suggestion)

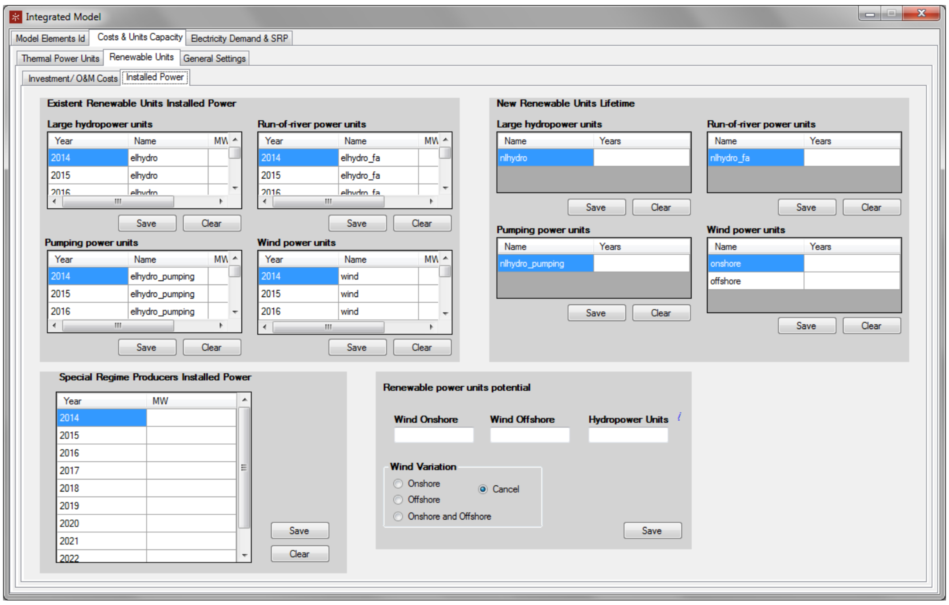


(b) Fuel and CO_2 coefficients curves (User choice)

Figure 6.19: Fuel and CO_2 coefficients curves data (Integrated Model)



(a) Integrated problem “Investment/O&M Costs” tab



(b) Integrated problem “Installed Power” tab

Figure 6.20: Integrated problem “Renewable Units” tab

and run-of-river power plants availability, large hydropower inflows, as well as its reservoir levels and pumping cost, the yearly peak load, the discount rate, and the emissions allowance costs. Power system security is taken into consideration by allowing user to set the spin reserve and reference margin. Reference margin can be calculated by pressing the "Reference margin computation" button, which will open the window shown in Figure 6.5 and already described for the generation expansion problem (see section (6.3.1)). Again, and like in the generation expansion problem, cost minimization can be calculated having into account a specific value for the CO_2 emissions (top right form in Figure 6.21).

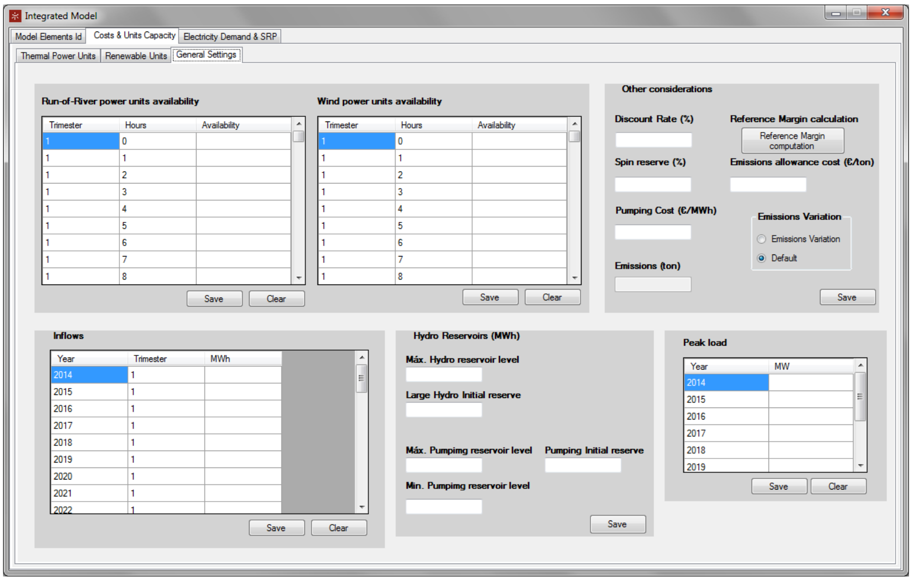


Figure 6.21: Integrated problem "General Settings" tab

The last tab, "Electricity Demand & SRP", is where user can update electricity demand as well as SRP parameters. Due to complexity and high dimension of this problem, integrated model assumes four trimesters for the calculations. Each trimester represents a season of the year and its assumed that in each trimester, respective months will share the same system behavior. After inserting and saving all data, optimization results are obtained by running the model, which can be achieved by pressing the button "Run Gams". Once again, results will be saved in an Excel file (.xlsx) named integrated_model and located in the GAMS project directory (typically in the $c:\backslash Documents\backslash gamsdir\backslash projdir$).

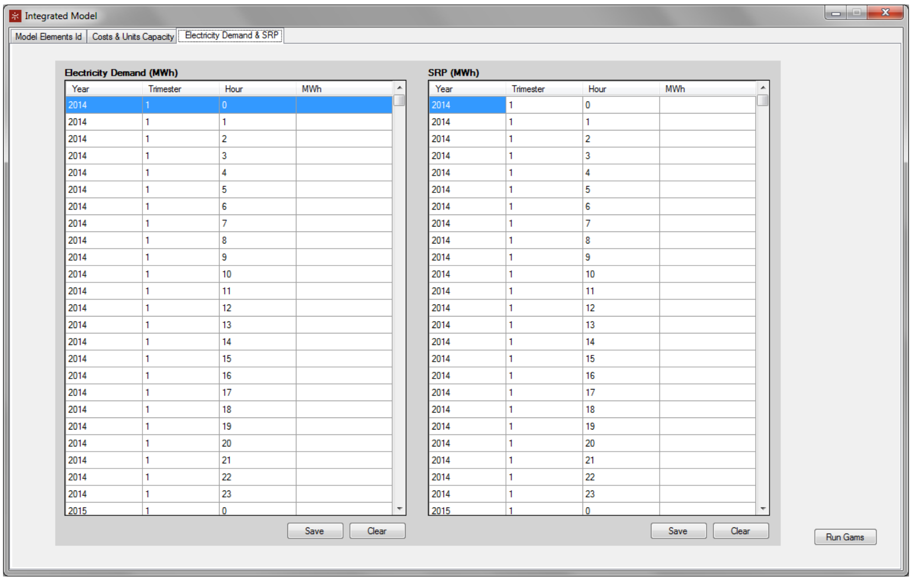


Figure 6.22: ESAM tool “Electricity Demand & SRP” tab

6.4 Conclusions

The existent tools to support energy decision making are deemed to be essential due to the changes evidenced over the years in the paradigm of energy sector and the required effort to proposed future scenarios and energy policies. In what concerns to the electricity sector, these changes are mainly related with the development of new and more environmental friendly technologies and consequently their impacts on the power system. Thus, the task of the decision makers becomes increasingly complex and so, the usefulness of optimization tools is evident, allowing to deal with large problems with high number of variables and constraints that characterize the electricity systems. However, and in a general way, these tools are very complex, which difficult their dissemination among users not fully familiarized with programming/mathematics techniques. Furthermore, some of the available tools are not freeware and lack a proper easy-to-use graphical interface.

This paper presents a new tool used to support electricity decision problems analysis. Apart of covering both well known problems, frequently addressed in literature, as is the case of the electricity expansion and schedule problems, this new application also includes a simplified approach of the schedule problem, and a new model that results of the combination of the two previous ones (Integrated problem). The translation into the GAMS modeling language of the described problems would still be insufficient to completely help the user. As such, a graphical interface was developed supporting the user on the data input, models' simulation and analysis of the results. Thus, the goal of this tool is to allow the user to apply these problems in a more simplified and intuitive way, without losses of information, keeping results accuracy, and without neglect visual aspect. The application will be available as a freeware tool to be tested by different users, receiving feedback from them in order to correct possible errors, increase the quality of the tool and expand its usage by incorporating additional technologies or restrictions in the models.

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Chapter 7

Conclusions and Future Work

7.1 Conclusions

Energy decision makers face nowadays a hard task. Over the past years, changes in the paradigm of the electricity sector are evident and enhanced by the society new environmental concerns the depletion of fossil fuel and its increasing trend prices, and also by the increasingly reliance on RES technologies frequently characterized by its variable output. Therefore, from to all these changes, new challenges on the operation of the electricity system are expected to arise. The use of optimization models to support decision making in the electricity sector is extensively debated in the literature, discussing different methods and providing examples. However, the impacts of RES integration on long-term strategic planning models, is still not fully explored.

Usually, when applied to the electricity sector, two main problems are considered. One for the strategic generation expansion planning and other for the UC and economic dispatch. The difference lies mostly in the horizon time frame in which each one fits into. The strategic generation expansion planning, addressed in chapter 2, is the problem of defining which, when, and where a specific power unit should be installed, in order to meet the expected demand at minimum cost. This is a highly constrained problem which must be modeled from the technical, legal, and environmental requirements of the electricity system. The inclusion of technologies of variable output presenting a noticeable seasonable behavior, adds additional complexity to these models. In chapter 2 a MILP that considers both economic and environmental objective functions, subject to a set of constraints translating the legal, technical and demand requirements of the system was formulated. The model was applied and used to present possible optimal electricity scenarios for a system close to the Portuguese one, establishing investment and generation plans and evaluating the cost, emissions and external dependency. The results indicated that as the CO_2 objectives become more restrictive, in general, the least expensive solution was to firstly replace the coal by CCGT. According to the results, wind power contribution would only increase significantly for highly environmentally constrained solutions. These results may be explained by the low capacity credit of wind and the required hydropower reserve schemes directly related with the total installed wind power. The results also emphasized the possibility of considering different scenarios that, although not being optimal Pareto solutions, may be interesting from the strategic decision makers' perspective. This approach may be particularly useful to support multi-criteria sustainable electricity planning decisions, based on the evaluation of minimum (or close to minimum) cost scenarios taking into account environmental and social objectives.

Despite all benefits frequently assigned to RES power, a diversity of impacts, affecting mainly the operation and management of the electricity system, can be also associated with the increasing levels of RES, and in particular to wind power. According to scientific literature these impacts are usually related with increasing difficulties with voltage management, reduction of efficiency of thermal or hydropower power plants, increasing difficulty of the transmission system to accommodate wind generation, increasing reserve requirements and increasing on non-used energy. Chapter 3, presents a MINLP used to solve the UC problem. Along with a detailed model description, an analysis over the impacts of the increasing levels of wind power on an electricity system was presented. For this a wind-hydro-thermal power system close to the Portuguese one was used to test the model and to draw conclusions on wind power impacts. Results indicates that as the wind power capacity increased the overall marginal cost of the system tended to decrease. In the same way, results also confirms the reduction of the CO_2 emissions. These results are explained by the lower RES costs of operation and maintenance comparatively to traditional fossil fuel power plants and due to the fact that wind power production was assumed to be free of CO_2 emissions. Results also emphasized the importance of both wind and hydro seasonality, put in evidence on the marginal costs of the electricity system, that reached the highest values during the dry and low wind seasons. Regarding the impact of the increase of wind capacity on the operation of thermal power plants, the results demonstrated that CCGT plants would be the most affected ones. The variability of wind power output is shown to result on both the increase of the number of startups of CCGT and the reduction of its power output.

The model developed in Chapter 3, provided a detailed description of the unit commitment problem applied to a system close to the Portuguese one. However, the model was demonstrated to be very complex, resulting in high computation times. In chapter 4, a new and simplified approach of the model previously proposed is presented.

Aiming to reduce the complexity, a set of amendments where considered transforming a MINLP into a NLQP. Results evidenced that despite being a simplified approach, and as such discarding or simplifying some of the technical constraints previously included, the new approach allows to achieve good solutions that represent a good compromise between the quality of the results and the required computational times. The quality of the results was demonstrated through the comparison of the solution obtained with both models, showing that the simplified approach can be used as a first attempt to analyse a large set of different electricity scenarios and, select the most relevant ones to be analysed with the model proposed in Chapter 3, if further detail is required.

In the fourth paper, presented in chapter 5, an optimization model to apply to the analysis of the electricity sector was presented. Based on a multi-periodic approach combining optimization models for long-term capacity expansion (chapter 2) with models for the unit commitment process (chapter 3 and 4), based on short-term optimization of the available resources, this new model is coined as integrated model. This model provides additional technical considerations to the previously one proposed in Chapter 2. It allows in particular, to take into account the operational performance of thermal power plants avoiding the use of average operational conditions. The impacts of RES of variable output are then recognized and integrated in the model, resulting on more reliable estimations of costs and CO_2 emissions to be considered for the long-term scenarios generation. As in the previous chapters, the model was applied to an electricity system close to the Portuguese one, aiming to present future electricity scenarios and to compare the results with the ones obtained in Chapter 2. The results of both models show a similar trend, with the reduction of CO_2 limits resulting on the replacement of production from existent coal power plants by CCGT and even by new and more efficient coal power plants, and to less extent by wind power. The contribution of new wind power for the system only becomes relevant for highly environmentally constrained solutions, resulting from its higher investment costs but also from its impacts on the operating performance of thermal power plants. In fact, the integrated model results in higher costs for the same CO_2 constrained solutions. This comes from the use of both short-term technical constraints for thermal power plants and from the hourly variability of wind and hydropower output, now taken into account.

The conducted literature review and the design and development of the optimization models for electricity planning, demonstrated that the use of these models is strongly limited by their complexity and their lack of user-friendly interfaces. Users are frequently required to have expertise in both programming and mathematical field. Therefore, tools that support the use of these models in a more easier and intuitive way are considered to be essential and useful. The paper presented in chapter 6 aims to tackle this challenge. The development of a graphical tool (coined as ESAM) that will support the use of all models presented in this work is then proposed. The paper comprise an detailed description (manual) of “how to use” this tool, aiming to contribute to the extensive use of the results of this research. The users are challenged to freely use the models and apply them according to their interest in a way of testing it and obtain feedback for its improvement.

With this work, a deeper understanding of the impacts of RES integration in the electricity system was fulfilled, by formulating optimization models for long-term and short-term electricity planning and applying these models to a system close to the Portuguese one. The results proved that RES integration, and in particular wind power, can have relevant impacts on the overall electricity system and on the different power plants comprising it. In general, an increase on the RES share can result on higher average costs mainly due to the assumed investment costs, but will also lead to a reduction of the marginal costs of the system and of the CO_2 emissions. However, it became obvious that the computation of the marginal cost and CO_2 emission reduction cannot be based on the simple assumption of substitution of electricity generation technologies. Increasing wind power in the system, will affect the operational regime of thermal power plants both on their load factor and utilization factor. The quantification of these short-term impacts must then be taken into account during long-term strategic planning.

Recognizing RES impacts, a new integrated optimization model for strategic electricity planning was developed and tested allowing to conclude that these impacts are relevant and, as such, they should not be overlooked during the design of future scenarios. In fact, results showed that not contemplating these aspects can lead to underestimation of the costs of each scenario and to the overestimation of the CO_2 abatement potential of wind power, significantly influencing the choice of technologies to be added in the future.

This thesis showed that the use of the optimization models for drawing conclusions over the aforementioned aspects is of great benefit, but it was also demonstrated to be complex task and requiring considerable experience from the users. The work developed allowed to make an important contribution for the effective dissemination and usage of these models, by providing a user-friendly platform enabling researchers and stakeholders to deal with electricity planning problems in a simpler but reliable way.

7.2 Future Work

The work performed in this thesis was applied to the Portuguese electricity system that is comprised by a mix of thermal, hydro and wind power technologies. Therefore, all models developed in here can be easily adapted to assess the impacts of wind power in electricity systems close to the Portuguese one. Thus, one possible further development can be the application of the developed models to others wind-hydro-thermal system or to address an Iberian scale taking into account all the relevant technologies.

The technological development in what refers to renewable energy sources is evident nowadays. Despite wind power, other technologies such as photovoltaic and biomass are available in a commercial scale, and others such as wave or concentrated solar power are starting to emerge. In all models presented herein, all these RES technologies and cogeneration were assumed as parameters not included in the optimization procedure. Therefore, future research should consider models improvements by considering all these technologies taking into account their cost, technical and seasonal characteristics. This should contribute to disseminate the models even further, allowing to adapt it to electricity systems with different characteristics.

For the sake of simplicity, all models proposed in this thesis assumed a closed system, where cross-border was not included. However, the integration of the markets can have a relevant impact on strategic electricity planning in particular in what concerns the inclusion of RES. Future work should then address the interconnection capacity including this in the optimization approach, allowing then to draw scenarios taking into account the possibility of electricity importations and exportations.

One consequence of the emergence of the electricity markets liberalization is the creation of new generation companies, competing for the electricity commercialization. Contrary to the traditional centralized electricity generation systems, where the cost are to be minimized, in the liberalized markets, companies seek for profit maximization. Along with this, power production companies are also committed to minimize the impacts that RES may bring to their generation portfolio. Thus, both generation expansion and UC are usual problems to which electricity companies assign significant importance and therefore, future research may consider the developed models presented herein and apply them in the context of companies portfolio.