UNIVERSITY OF PIREAUS
DEPARTMENT OF INTERNATIONAL & EUROPEAN STUDIES

MSc IN "ENERGY: STRATEGY, LAW & ECONOMICS"

Electricity Portfolio Optimization

Cost minimization using MILP, in GAMS

Author: Agis G. Koumentakos
Supervisor: Dr. Athanasios Dagoumas

ATHENS

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On my own responsibility and being fully aware of the penalties stipulated under 22 par. 6 of Greek Law 1599/1986, I hereby declare that: The intellectual work fulfilled and submitted based on the delivered master thesis is exclusive property of mine personally. Appropriate credit has been derived from other sources. I am also fully aware that any misrepresentation in connection with this declaration may at any time result in immediate revocation of the degree title.

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Agis G. Koumentakos

Extended abstract

The present research was conducted in the context of my dissertation defense. In the present study, an optimization model is developed in GAMS. It is a mathematical program, that minimizes the total cost of a power supplier, in order to meet its demand.

In the introductory chapter lies a brief introduction of the modern energy sector. In particular, the energy sectors of the developed and developing world economies are presented and compared. Through this comparison, the noticeable differences between the two are distinguished, and the typical examples of China, the European Union and the United States are presented.

The second chapter presents the structure and operation of an electrical system, as well as its division into two main parts. The first is an electrical system that consists of producing, transporting and distributing electricity to the final consumer. Therefore, these individual parts are analyzed and presented, giving importance to the special need of electricity, in relation to other products, which is the constant balancing of production and demand. There is also a reference to the gradual load reduction, and the pre-existing and modern methods of electricity storage. The other main part of an electricity system is the electricity market and its whole structure. Therefore the organizational and legislative framework of such a market is presented, as well as some basic organizations and regulations, that are the foundations of its proper functioning.

The third chapter constitutes the literature review in which emphasis is placed on day ahead electricity spot markets (SM), as well as demand response (DR) programs. As far as the SM is concerned, there is a brief review of the available products in some of the largest European energy markets, such as those in Hungary (HUPX) and Germany (EPEX Spot). In terms of DR, a brief classification based on recent research articles is initially presented. Further emphasis is placed on the relevant techno-economic costs of DR integration, their operation, and the different degree of interest and participation of certain categories of consumers.

The fourth chapter consists of the presentation of the problem, and the creation of the optimization model. The problem concerns the optimal management of an electricity providers energy portfolio, in order to fully meet the demand. This provider has three tools at its disposal: the production of energy from a natural gas power plant, the purchase of natural products by SM, and the reduction of cargo by a portion of consumers. The developed model is based on a pre-existing model, which is available to the public through the GAMS library. Specifically, two new models are created which are an evolution of the original.

The fifth chapter presents, compares and analyzes, the results between the original model and the two new developed. Specifically, the second of the two new models is the final, while the first is the transition from the original. The final model developed achieves a significant economic optimization, approximately 9% in the expenses of the provider compared to the original.

The last chapter constitutes the conclusions of the research and suggests the possible future research that would be worthwhile.

Contents

Table of Abbreviations

AC	Altering Current	***CPP***	Critical Peak Pricing
ACER	Agency for Cooperation of Energy Regulators	***RTP***	Real Time Pricing
CAES	Compressed Air Energy Storage	***BLC***	Base Load Contract
DAM	Day Ahead Market	***PLC***	Peak Load Contract
DR	Demand Response	***12-hour PLC***	Peak Load Contract o twelve hours duration
DSO	Distribution System Operator	***4-hour PLC***	Peak Load Contract o four hours duration
ENTSO-E	European Network of Transmission System Operators for Electricity	***EPRI***	Electric Power Research Institute
EU	European Union	***EUPHEMIA***	Algorithm solving the coupling of the day-ahead power markets in the PCR region
GEMA	Gas and Electricity Markets Authority		the zonal price
IEM	European Internal Energy Market	e_b^{DR}	the contribution of the total energy curtailed in the specific segment b
IoT	Internet of Things	***MAR***	Minimum Acceptance Ratio
MAD	Directive 2003/6/EC on Market Abuse	***HUPX***	Hungarian Power Exchange
MiFID(II)	Markets in Financial Instruments Directive (2004/39/EC)	***b***	the segment indicator

NRA	National Regulatory Authority	***Z1,Z2,Z3***	Zonal pricing borders for the DR
OECD	Organization for Economic Cooperation and Development	***TYNDPs***	Ten-year Network Development Plans
P2G	Power to Gas	***TOU***	Time of Use
PV	Photovoltaic	***DLC***	Direct Load Control
REMIT	Regulation of Energy Market Integrity and Transparency	***LFC***	Load Following Contract
RES	Renewable Energy Sources	***EIP***	Energy Infrastructure Package
TSO	Transmission System Operator	***SM***	Spot Market
US	United States (of America)	***TEN-E***	Trans-European Energy Networks
N^B	the total number of distinct price zones/segments	***2-hourPLC***	Peak Load Contract o two hours duration
μ_b	an indicator of the DR zonal prices	***EPEX Spot***	European Power Exchange
p_t^{PP}	the output capacity of power in MW of the power plant at time period t	P_{max}^{PP}	the maximum power output of the power plant
p_t^{SM}	the power curve of the quarterly power from the Spot market	$P(t)$	the curve of power demand
α, β	the number of BLCs and twelve-hour PLCs respectively in MWs	T	the set of quarter-hour time slices per day
$\gamma_i, \gamma_j, \gamma_t$	respectively in MWs	C^{SM}	the total cost the provider pays for buying power from the SM
D_{act}^{PP}	the duration of each power level measured in quarters	C^{BL} C^{12HPL}	the costs for one MW(contract) of the BLC and the 12-hour PLC respectively

c^{total}	the total cost beared by the provider in order to meet the demand	C_i^{4HPL} C_j^{2HPL}, C_k^H	the quarterly cost of each flexible PLC and the hourly product respectively
c_{ER}^{DR}	total cost for the day ahead DR	e^{total}	the total daily energy provided in MWh
C_b^{DR}	the accumulated cost up to segment b	c_F	total cost of "Flexible PLCs"
P_t^{total}	the total power provided at time slice t	c_I	total cost of "Fully Integrated"
c_p	total cost of "poutil"	P_t	the day ahead demand in quarterly frame
$\gamma_i, \gamma_j, \gamma_t$	the number of 4-hour PLCs, 2-hour PLCs and hourly products	t	Quarter time slice
$\boldsymbol{I}$	dyadic indicators of specific time periods		

Table 1 Abbreviations

Chapter 1: Introduction

1.1 The Modernized Energy Sector

The modern energy sector is constantly evolving. At the same time global energy consumption is increasing although the environmental implications mostly due to the developing economies. The energy sector is greatly correlated and affected by other sectors such as technology, climate etc. The energy mixture globally and regionally is in a transitional stage were traditional sources are falling and modern ones are rising. Factors such as population growth, prosperity and technology availability might be significant shaping the energy sector in one region, while environmental issues, efficiency and geostrategic balances are key factors in another. In developed countries, the growth of energy demand is falling and could soon become slightly negative. This result is partially due to the growth of energy efficiency, that in contradiction to the developing economies, the developed ones have set as a priority. A more thorough presentation of the energy sectors in developing and developed economies is given below. Electricity markets play a pivotal role in energy sectors' efficiency both by reducing the energy volumes required as well as the economic impact of these volumes and are presented in Electricity Market Structure .

1.1.1 Developing economies

As far as the developing economies are concerned, their energy sector is shaped mainly by the rising energy demand. One important reason is the population growth which is a common characteristic of most developing economies and follows the logic that, the greater the population the more the energy needs. The growing energy needs of a rising population emerge in sectors of construction, electric power, transportation and industries. Along with this, prosperity plays also a significant role. It works as an amplifier of the population growth, in the sense that more people are transitioning from a poor to an average economic state. By acquiring more "conveniences". Such an example is the constant increase of the people using a private car instead of public transport, or traveling more often than before, which in both cases raises the fuel consumption. Moreover let's not neglect the fact that even in 2020 there is a great number of "electricity poor" people, that will, and most importantly should receive such conveniences too. Of course this ends up adding to the future energy consumption.

When referring to the energy sector of developing countries there exist economies that play a pivotal role and constitutes the major players among the rest. These economies or countries/regions are not other than China, India, Africa as whole and the rest of Asia, which do share a common characteristic regarding their energy sectors. All these economies are expected to face growth in their energy consumption for the year 2020 and this growth will continue while in some cases consumption might even double in size [1].

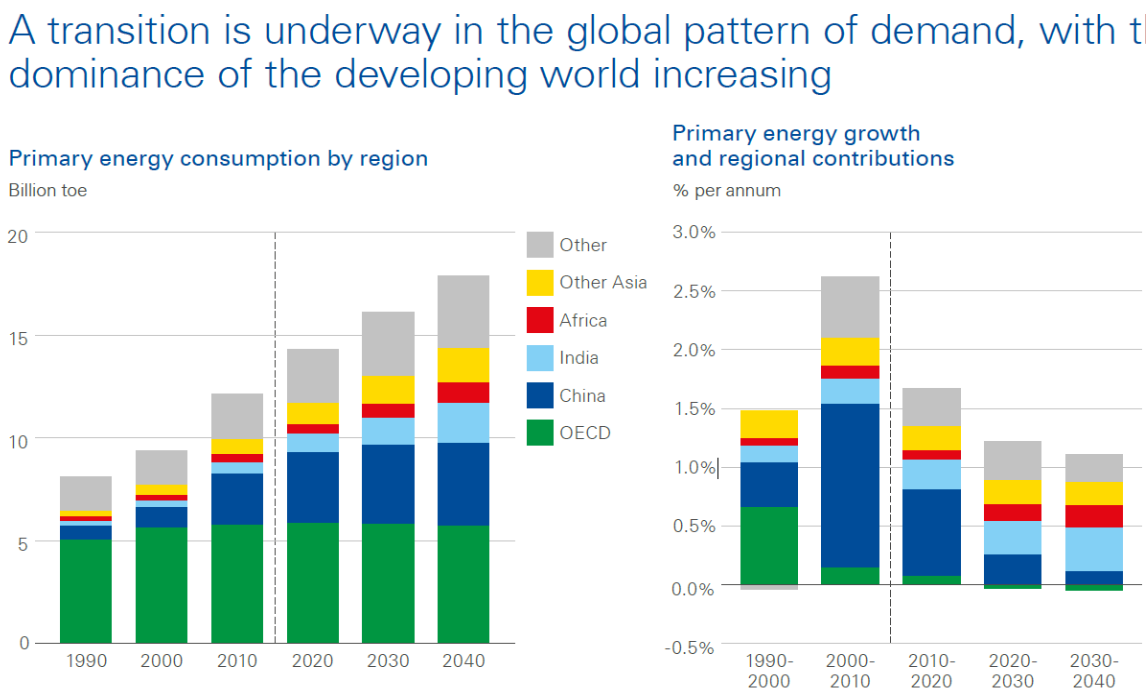

Figure 1.1Enenrgy consumption and growth [1]

It is easily observed that apart from OECD countries, in which belong many developed economies, the rest of the countries have an increasing energy consumption. Such a difference in the energy consumption trends between the countries is obviously creating other differences too. These differences are a result of the different needs that each economy has, especially when comparing developing to developed ones. Among such differences are government priorities, goals, but also more practical as the energy mixture.

Generally countries with a constantly rising energy demand, will try to satisfy it by increasing their energy production and imports. The rate by which their energy consumption is rising pays a very significant role when choosing the appropriate ways to cover it. A characteristic example of such is China which has most of the aforementioned characteristics. Firstly it has the biggest population globally and tries to reduce it's growth by extreme measures (increasing taxes for having more than one child). Secondly, China had a great economic growth the last decades which, only the last years, seems to be reaching a steadier rate. At the same time China is the country with the greatest energy consumption and is anticipated to remain so. Such a situation undoubtedly affects the country's energy sector that sets as a priority the fastest, economical and low risk means of meeting the growing demand. As a result, China has the greatest coal consumption worldwide. Coal is probably the worst mean to produce energy from an environmental and public health perspective, but is cheap and easy to construct. Although China is doing very impressive efforts to improve its renewable sources, owning nuclear, wind, solar and even four out of the ten biggest hydroelectric stations in the world, it's coal consumption is still greater than the notional amount of every other country.

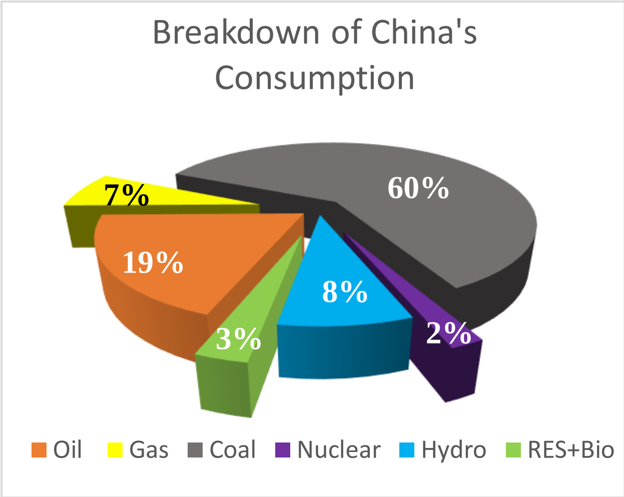

Figure 1.2 China's energy mixture 2018

The rest of the developing countries face a similar situation although not in such a scale, however they follow the same principles of inefficient and non-ecological energy production. This, as already mentioned, affects the energy mixture having great, if not absolute, dependency on coal or oil.

Figure 1.2 shows the energy mixture of China as the most characteristic and important example of a developing country's energy sector. The vast majority of energy consumption is met by coal while oil remains at steady levels and natural gas along with RES & other are confining further coal consumption.

1.1.2 Developed Economies

In contradiction to developing economies and the example of China, developed economies have quite different needs to cover as far as the energy is concerned consequently they do have quite different energy mixtures. Two of the most characteristic examples of developed economies are these of United States, US and the European Union, EU. These two differ in key characteristics, for example US has recently become a net exporter of energy while EU remains a net importer. Moreover EU prioritizes the reduction of it's energy dependence, mainly from Russia, and the environmental impact of it's energy sector. On the other hand US wants to strengthen it's role as a net exporter and control the rising global influence of China.

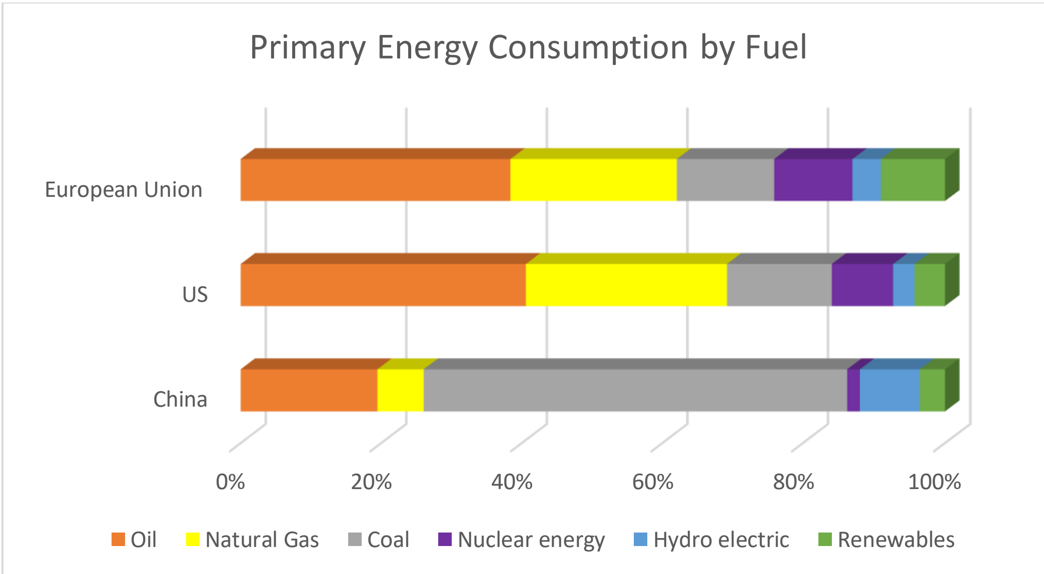

Figure 1.3 The energy mixture of EU, US and China

Although US and EU have completely different strategies and roles concerning their energy sectors, they do have quite similar energy mixtures. The above Figure 1.3 presents the energy mixture of the three characteristic examples of EU, US and China. US does have a greater utilization of oil and natural gas as it is producing a great amount of its requirements. This is for a most part a result of US technological breakthrough in hydrocarbon exploitation. The "shale boom" along with the method of "horizontal drilling" gave US the advantage in becoming an energy net exporter [2]. On the other hand EU lacking such a technological advantage while also facing regulatory issues in on-shore drilling, has developed further it's energy production from nuclear and renewable energy sources, RES [1].

In contrast to the relatively small differences between US and EU energy mixtures, they both differ significantly from China. This difference, as presented in the above figure, is mainly in respect to energy production from coal. One reason could be that US and EU do not have such regional abundance in coal as China does. However, this is not always the case as some particular states of EU do have such an abundance, for example Greece, but do share such great dependency on coal as China. The main reason is , as stated before, the different needs of these economies. The social, economic, strategical and environmental targets that do affect and shape the energy sector and specifically the energy mixture. EU and US both being developed economies, have focused the transformation of their energy sectors in areas such as efficiency and environmental impact reduction. Unfortunately, US has not yet signed the Paris Agreement about environmental protection and sustainability of the future energy sector [3] [4].

A modernized efficient energy sector, to which both EU and US aim, does operate mostly on natural gas and electricity. Natural gas is could be used directly for heating or in industries such as refineries, or as fuel for power production.

The modernized energy sector is also characterized by the growing electrification. Electricity is the fastest-growing source of final energy demand expected to outpace the total energy consumption. The power sector now attracts more investment than oil and gas combined concerning two main purposes. Firstly, great changes in the energy mix especially in developed economies, as explained above, require new investments. Secondly, the already operating power plants, mainly coal-fired and nuclear, face ageing issues and require upgrades. The latter is accelerated by the obligatory decommissioning of all coal power plants until 2030 [5].

Significant changes in the evolution of the modern energy sector constitute on a great if not absolute , extent the growing RES. Wind and solar power have already changed the energy landscape by their intense integration. The latter do come with great advantages regarding efficiency, environmental impact both air pollution and climate change, and distributed generation. On the other hand their growing integration requires drastic changes in the design of the existing and future electricity systems. Failing to sufficiently transform the electricity systems might lead RES and electrification in creating more problems than the ones called to solve. Therefore it is of great importance to take all the required measures from an economic, technological and social point of view to guarantee the successful transmission to the modern electricity systems and energy sector in general.

Chapter 2: Analyzing the Electricity System

As stated above, electrification is growing and this means that electricity is constantly becoming more vital not only for social development but also for survival. The role of electricity in today's society could be likened to that of blood in the human body, as it is running around every part(of society) to continue operating and developing. Electricity brings light, heat, transport, communications and is a prerequisite for an internet connection. The growing electrification is the base of the as well growing, digitization which brings IoT, blockchain and many more emerging technologies of the modern era. A couple of hundred years ago humanity could survive without electricity, today the picture has changed completely and a life without electricity is almost unthinkable to the majority of the world.

Having established the importance of electricity, the importance of electricity systems becomes evident. The electricity system can be defined as a system that includes the creation of electricity, the final point wηere the electricity is used and everything in between those two. Therefore, on one hand an electricity system consists of the physical infrastructure for electric generation, the means of transport and the final use and on the other an organized electricity market that controls these operations physically and financially.

The physical grid through which the electricity flows interstate or cross border, consists of electricity generators and transport systems. The latter are subdivided into systems for transmission over long distances and distribution systems that distribute electricity to residential and industrial consumers.

The different roles and relations inside the electricity system can be seen in the Figure 2.1 General overview of an Electricity system .

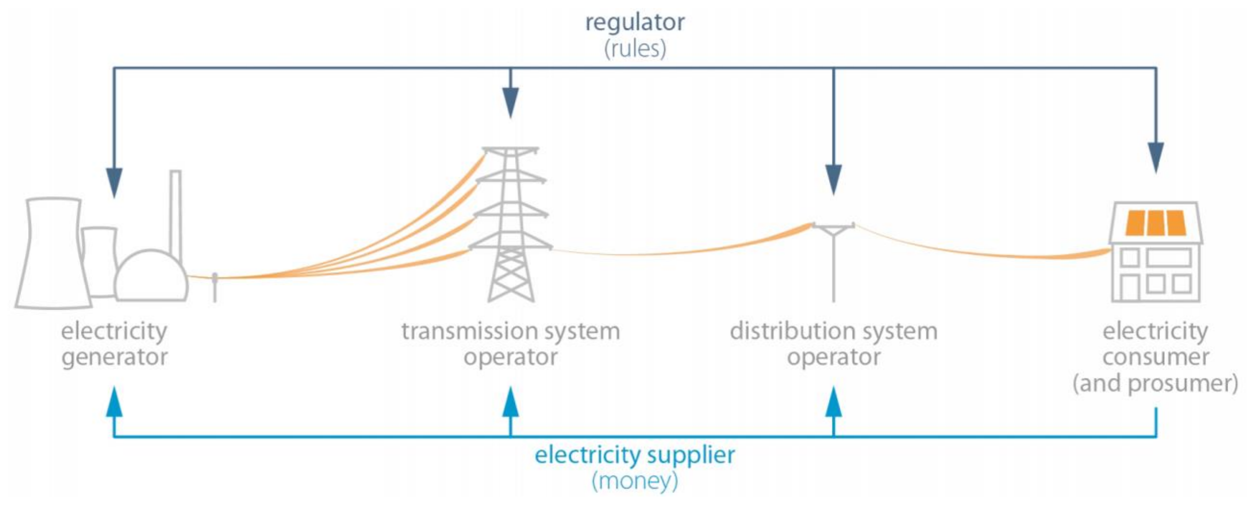

Figure 2.1 General overview of an Electricity system [6]

2.1 The Electric Grid

The electric grid as stated above consists of all the required hardware for the production and delivery of electricity. This involves everything from the electricity generators producing power to the last meter of cable delivering that power to the final consumer. This section provides a short overview of all electric grid contents.

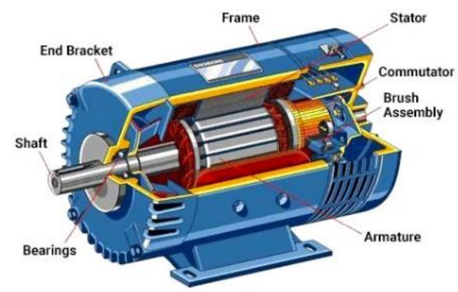

Figure 2.2 Electric generator operating principles

2.1.1 Electricity generators

As an electricity generator can be considered anything that transforms any kind of energy such as thermal, kinetic etc. to electricity. Figure 2.2 gives an idea over the operating principles of a simple generator.

However the electricity generators operating in the electricity systems are very specific. One way of clustering the different kinds of generators is based on their generation capacity. Specifically they are separated in firm and variable- capacity generators. Firm capacity generators are those which produce constant amount of power regardless of any external factors. On the other hand variable-capacity generators are those which their production is directly affected of external factors.

The energy sector is using for decades thermal powerplants to meet the electricity demand. Thermal powerplants belong in the first category of firm-capacity generators and are an inseparable part of every electricity system. In this category belong coal, oil and natural gas power plants which are also known as “fossil fuel stations”. The great majority operates as thermal units, where the fuel is burned to create steam by heating up water. The steam flow, in turn, gives the kinetic energy that is afterwards turned to electricity.

As far as the variable-capacity generators are concerned, they are directly affected by outer factors, thus in this category belong generators that do not operate on fuel. The most characteristic example of such generators are RES._RES such as solar PVs and wind depend on weather which is constantly dynamic creating the variability at the power output of the generator. Variable capacity is a characteristic that increasingly affects modern electricity systems through the integration of RES.

Figure 2.3Photovoltaic park

Figure 2.4 By © Hans Hillewaert, CC BY-SA 4.0

The figures on the left show a solar PV park and an off shore wind park. Although thermal units along with PVs and wind turbines, cover most of the energy mixture landscape there still exist another important generator. Of course this is nuclear energy that although it does not belong in the RES category is a very promising source from an environmental aspect. Nuclear energy is the example that introduces another way of sorting the numerous generators called flexibility.

Flexibility regardless of the generator being fix or variable capacity sorts the generators based on their ability to increase or reduce their power output when required. Some kinds of generators are appropriate for providing fixed amounts of power for longer periods whereas others are ideal for meeting the rapid fluctuations that exist in the power demand. For example a coal fired power plant is relatively flexible as it can increase or decrease its power output from one hour to an other and less. The same goes for natural gas fired powerplants which more flexible than coal and do also have smaller turn o/off duration and cost. On the other hand nuclear generators, which are used on a great extent in western EU, are extremely inflexible due to the nature of their “fuel”. Therefore, nuclear powerplants are only able to provide a constant steady amount of power.

2.1.2 Transmission networks

The production of electricity is of vital importance for any society this days. However, an untrustworthy transmission network can comprise the whole electric grid. In contradiction to the power generation sector, which in the majority globally, consists of numerous different generators, the transmission network is only one. The significance of these network is well-known, therefore most of the times the transmission system operator TSO is the state itself. Controlling this network is equal to controlling the states electric grid. Taking into account the absolute dependence our societies have on electricity, makes obvious its significance.

From a technical perspective transmission networks are networked grids that transmit electricity over great distances. They are different from the networks that distribute electricity to homes or small industries. This difference is because transmitting electricity over great distances creates significant amount of losses. Therefore, transmitting low voltages, as the ones powering homes, would be completely inefficient. In order to travel long distances electricity must be of very high voltages up to 1000kV. In the majority, such networks run on alternating current AC however there are some examples of direct current too. Such an example is the cross-border network cable between Italy and Greece lies from Aracthos (Greece) to Galatina (Italy).

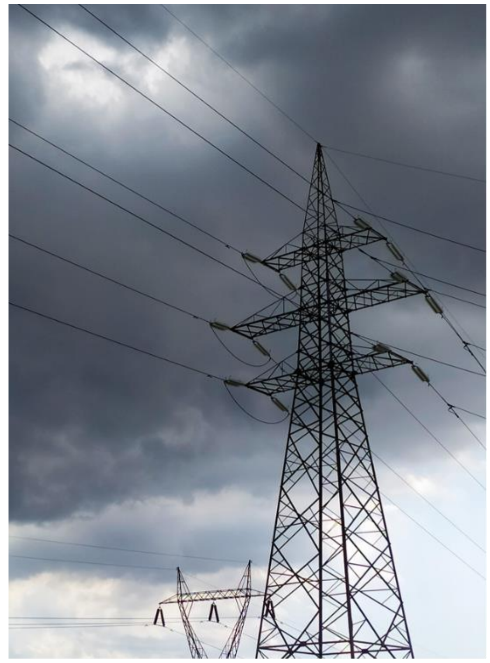

Figure 2.5 Electricity transmission tower

In light of the above example, it is worth noting that the importance of these networks goes beyond the national borders of each country. These networks are also responsible for exporting / importing electricity to neighboring countries. Particularly in Europe in recent years the efforts to create a single pan-European electricity grid have been steadily increasing. The final network will include even the easternmost member state of the European Union, which is none other than Cyprus. The benefits of such an association are innumerable, with only a few related to the quality of life of Europeans, the improvement of the reliability of the network and the geostrategic position of the European Union in terms of its energy. A similar logic applies to gas as the European Union through its Member State, Cyprus, especially now with new discoveries of hydrocarbons within its independent economic zone.

As far as the electric pan-European interconnection is concerned there has already been created a respective organization. The European Network of Transmission System Operators for Electricity abbreviated as ENTSO-E, consists of all the TSOs of the EU member states and is responsible for the development and operation of the pan European electricity transmission network. Some key figures regarding the network can be seen below [7]:

- 41 transmission system operators
- 34 European countries
- 532 million customers served
- 312,693 kilometres (194,298 mi) of transmission lines
- 3,174.2 TWh electricity transported
- 423,586 GWh of electricity exchange between member TSOs
- 1,023,721 MW net generation capacity connected to the grid

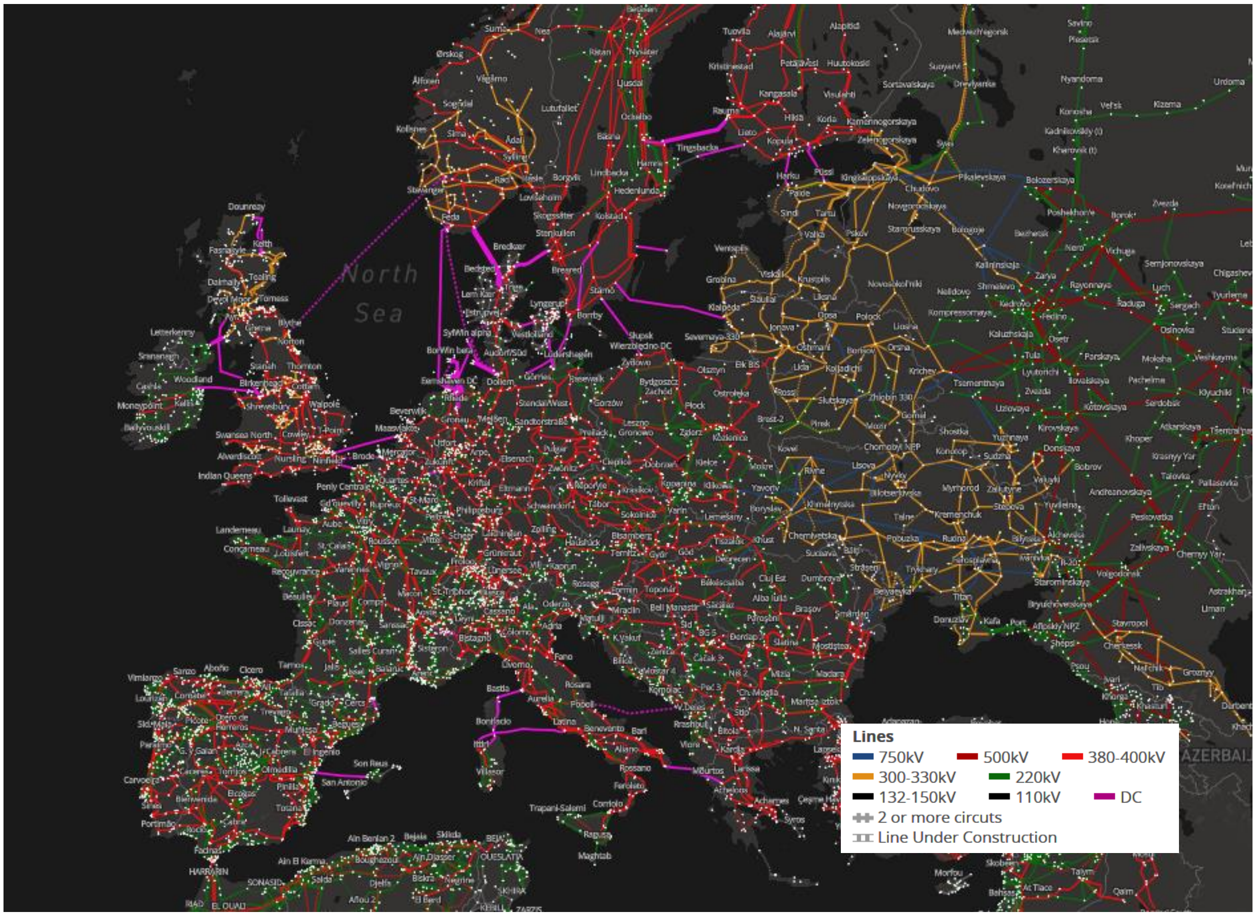

Figure 2.6 ENTSO-E Transmission System Map [8]

2.1.3 Distribution networks

These networks are responsible for distributing electricity to the final consumers e.g. households. They do so by receiving the electricity from the transmission system after being converted to from high to mid or low voltage. Respectively to the Transmission system the Distribution is managed and operated by a Distribution System Operator (DSO). The DSO is responsible for the proper operation, service and development of the distribution network. In addition to the Transmission system the DSO is also provided with energy from smaller (>1MW) RES such as rooftop solars, small PVs or small/medium wind turbines. These low voltage RES do not require any downscaling and therefore are directly fed to the consumers in contradiction to big solar or wind parks. The below (Figure 2.7 General layout of electricity networks. The voltages and loadings are typical of a European network), represents a characteristic example of the electric grid. In this particular shape all those distinct and integral parts of the grid are clearly visible.

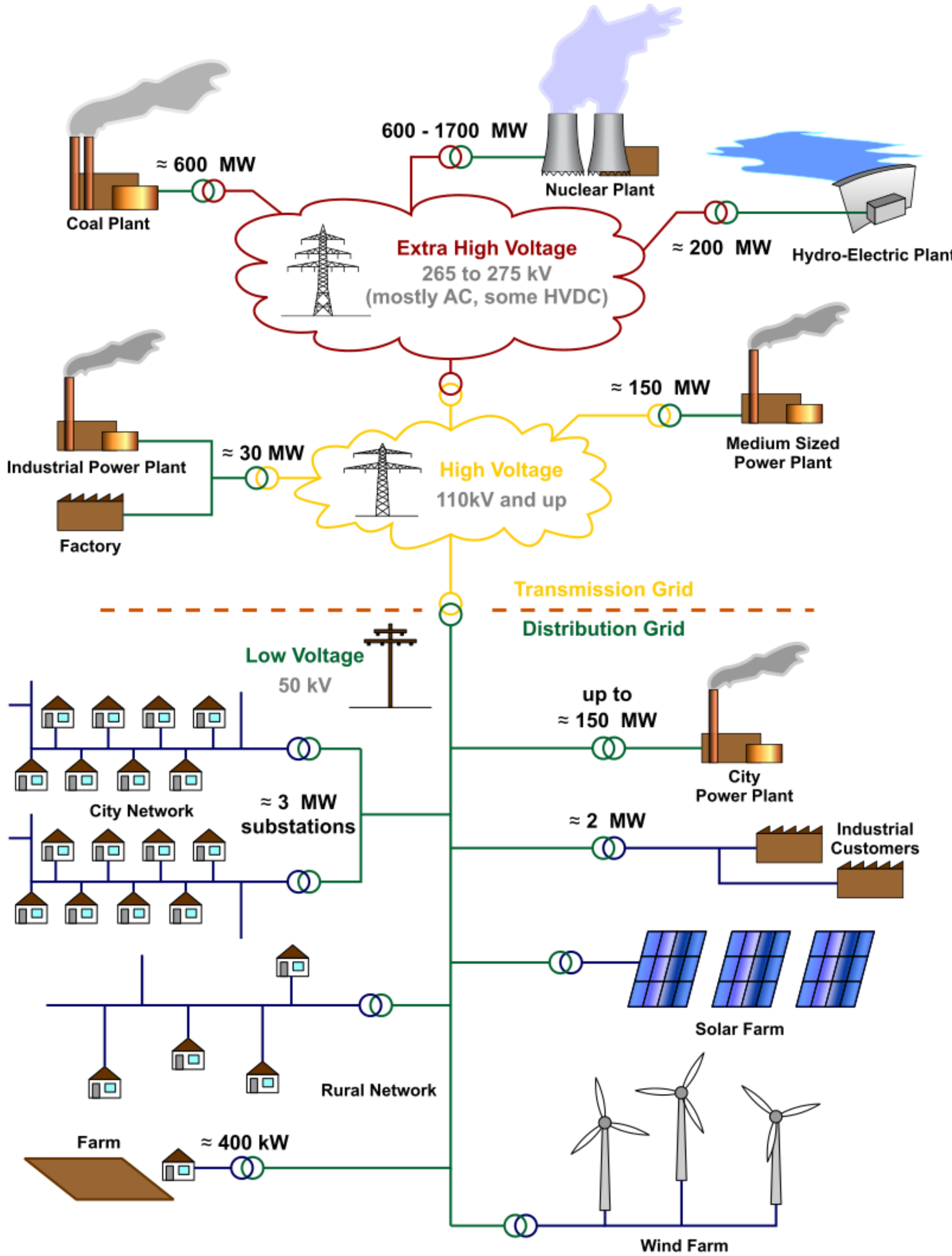

Figure 2.7 General layout of [electricity networks](). The voltages and loadings are typical of a European network By MBizon - Own work Originally derived from de:Datei:Stromversorgung.png, CC BY 3.0, https://commons.wikimedia.org/w/index.php?curid=9676556

At first energy is produced from big generators either thermal such as coal or hydroelectric dams. The power produced if of extra high voltage and therefore fed to the extra high voltage part of the transmission network. The rest generators of medium voltage can either feed their power output to the high voltage transmission network or directly to the regional distribution network. The medium voltage generators do also include the respective RES, which are also able to connect directly to the distribution network. Finally, the energy is distributed to the final consumer whether these are households or small industries.

2.1.4 Balancing supply and demand

Electricity is increasingly being traded globally, however has a great difference compared to other commodities. Electricity cannot yet be storage in great amounts as other commodities can. This difference is of great significance as it affects directly the entire electric grid. The inability if electricity storage means that production and demand of power must be constantly balanced. In the occasion of failing to satisfy this constraint the systems risks breaking down.

For many years this problem was tackled by utilizing low flexibility generators for meeting the baseload meaning the fixed load throughout a day and flexible ones to meet the demand fluctuations met during peak hours, known as peak load. However, in our days the environmental impact has changed the energy mixture that includes mostly natural gas-fired powerplants and RES. The problem emerges because RES have an increasing participation in power production, hence increasing the variability of the system that is affected by outer factors such as solar radiation and wind.

In light of this problem, the electric grid must guarantee security of electricity supply. It does so utilizing the electricity market, by putting in some reserves responsible for providing the additional flexibility required by the system to deal with the spontaneous changes in the load requirements. These reserves are sorted in primary, secondary and tertiary depending on the maximum start up time demanded by the system. The existence of such reserves technically solves the problem of the required flexibility. However, such reserves are not always economically advantageous for the power producers, as the daily demand for reserves is often minimal. The problem is further aggravated by the priority given to renewables in feeding the European grid, which very often leads to variable renewable generators covering most or even the entire energy demand forcing the rest generators to operate for small time periods. The latter creates also a great reduction in the electricity prices that occasionally reach even negative prices. All the above put great economical pressure on conventional electricity generators.

2.1.5 Demand response

The above problem tackled by the reserves can be also solved by demand response. Reserves are additional power produced when demand is unexpectedly increased either due to less production of RES or an increase in actual demand. On the other hand Demand Response or DR does exactly the opposite by curtailing the additional load that would require the utilization of reserves in order to be met.

Of course the capability of DR in a market requires certain steps to be taken before the integration. Such steps could vary from the education of the market operators and the consumers to more practical such as the necessary technological interventions e.g. installations of smart meters. DR is further explained and reviewed in [Demand Response](#)

2.1.6 Energy storage

It is stated above that one great disadvantage of electricity compared to other commodities, is the inability of being stored. Of course this argument refers to storing huge amounts of electricity easily and economically as happens with other commodities. Storage of electricity is completely feasible for many decades now through batteries and other technologies. The ability to store even small amounts of energy for specific periods of time and feeding it back into the network later contributes significantly in balancing supply and demand.

Energy storage as well as DR are not only used for securing the system from failing to meet the demand but most of the times are utilized to control the energy prices especially during the peak hours to avoid irrational increase or decrease. The available technologies for storing energy are numerous, therefore only some of the most characteristic are presented below.

Another method known as Compressed Air Energy Storage or CAES uses electricity to compress air into a storage tank at off-peak times, when prices are lower. At later periods when prices are higher the air is decompressed producing electricity that substitutes the marginal production during peak hours. This mechanical method has losses that are considerably small making this method ideal especially for big amount of energy storage.

Picture XX represents the method of pumped storage. This method of storing energy is the most common in modern electricity grids. The logic is similar to that of the previous method except that this time the fluid that is stored is not air but water and is not compressed. Specifically water is driven on a higher altitude during off-peak hours and released to flow back to the lower altitude producing electricity through a generator in peak hours.

Another energy storage method worth mentioning are batteries, chemical batteries to be exact. Global research has focused the last years on big capacity battery systems. These batteries follow the same operational principles of a classic battery, but are evolved in terms of time of charge, maximum power output and energy density, meaning the amount of energy that can be stored per volume. Such batteries are already installed and operating in some electric grids in US, China and EU. The first results of this technology so far are very encouraging, which has led to an increase in their participation in electricity networks around the world.

Another relatively new method, such as CAES, is hydrogen. Recently, hydrogen has been able to join the fuel family even with a minimal percentage of the global production. Many areas of technology are expanding their research on hydrogen utilization, such as the automotive and maritime industries. Hydrogen is generated by chemical processes such as electrolysis. Its correlation with electricity is therefore obvious which seems useful in terms of energy storage. The modern method of Power to Gas or P2G, considers the use of electricity in off-peak hours for the production of hydrogen, which in turn can be utilized as other gaseous fuels, or burn and re-generate electricity in peak-hours with the respective losses.

2.2 Electricity Market Structure

In the previous section, the electric grid and its importance were presented, likening it to the blood circulating in our bodies. Similarly, the electricity market could be likened to the heart of the human body. The electricity market has as its primary concern the smooth, safe, economical and transparent operation of the entire electricity system.

However, electricity markets were not always transparent, as they became liberalized the last years. At start, the majority of markets were owned by the state, forming a monopoly. Those markets had the state responsible for the entire electricity system by controlling all of its distinct parts: production units, transmission and distribution networks. As it happens in every market with monopoly, competition is absent along with transparency.

Through the years the markets started becoming deregulated by introducing some private "players" in the market, while also splitting vertical players. However, there still remains a part of the modern markets that cannot be deregulated for open competition. The electric grid is often referred to as a "natural monopoly", because it belongs exclusively to the one who constructed it in the first place. In all cases, the owner is the state. Clearly, if such a case remained "unregulated", would cause great harm to the smooth and fair function of the market. This is precisely the reason why in most markets the independent network operator works under very strict regulations aimed at preventing actions contrary to market principles.

The rest of the electricity market refers to the starting and the end point of the electricity system, which are, as stated before, the production and the final consumers respectively. Both sides are easier to liberalize. As far as the production is concerned, liberalization took place with the introduction of more producers from the private sector. At start, investors were given incentives in order to enter the production sector, referred also as supply side.

Then the producers, both private and state-owned, sell their produced energy in the market. For this operation to work, the majority of electricity markets uses two models globally. The first model wants all the producers to take part in the so-called wholesale market, by informing the market operator about the available power they are willing to produce. This model is known as 'mandatory pool'. The market operator receives scheduled power outputs of all the producers and is also informed about the technical specs such as the start/stop costs of each. Afterwards, the operator takes into account the electricity demand and runs a central dispatch optimization model, which aims at meeting all the demand with the minimum cost, securing technical feasibility as well. This method is considered to provide the most feasible solution, as takes into account the technical constraint of the system. Such a constraint are the maximum capacities of the network, which constraint the power transferred, in order to preserve the balance of supply and demand throughout the system operation.

On the other hand, the second model includes power exchanges, where again an initial dispatch and trading takes place. In this model, the producers are bidding their power quantities. However this is not mandatory. This method provides the producers with the additional capability of selling energy outside the market through bilateral contracts. Another difference is that power trading is also executed by the demand side through the retailers or other stakeholders, such as traders. Therefore, the exchange receives the bid and ask signals from all the stakeholders involved and matches them through an optimized process. This method is similar to the operation based on the classical economical school of thought. It does however carry the disadvantages of disregarding the technical constraints, occasionally leading to infeasible solutions. In such occasions, the model reruns the code until a feasible solution is found.

Regardless of which method is selected by the operator, the special characteristic of electricity remains compared to other commodities remains. The inability to store large amounts of energy creates the need for constant supply and demand balancing. This specificity makes it possible that a slight change on the part of demand or production, may dilute the functioning of the whole system. It is virtually impossible to direct this equilibrium when so many stakeholders are involved. For this reason, the market solves the algorithm on the day before delivery, known as day ahead market or DAM. There also exist markets that operate intraday, meaning some hours before delivery, and real-time markets operating even five minutes before delivery. However, this favors mostly automated trading or imbalances created from the DAM. Additionally, a Balancing market exists, responsible for any imbalances left, that the operator is obliged to deal with charging the related cot to the responsible members.

It is also worth mentioning that in an electricity market, there exist two categories of products to be traded. The first is the purchase of physical energy quantities and their transmission capacities that will deliver the energy cross border if it refers to imports or exports. The second component of an electricity market is the purchase of financial derivatives, which can be “futures” linked on physical quantities or not and belong in the Derivatives Market.

2.3 EU Policies, goals and regulations

As any other market, the Electricity Market, thus the entire electricity system can not operate deregulated and must serve the common good by strengthening the economy and improving the social welfare. A power market should operate in a way that promotes investments in the electricity sector. This is achieved by allowing the long-term engagements of the stakeholders, providing at the same time the required conditions for the recovery of the investments. In addition to that, the market must support social cohesion intergenerational solidarity, promoting economic and environmental development.

2.3.1 Main goals of the regulatory framework

To achieve all the above, the regulatory framework has three main goals in general. The first goal is securing the consistent supply of electricity that is based of consistent and undistracted operation of the production-supply. The second concerns the services to the consumer and the third is about the protection of the environment.

Starting with the security of supply, this target includes all investments regarding the production and supply of fuels required for the thermal units and all parts of the electric grid, such as: generating capacity, transmission and distribution networks. Moreover, the security of supply has also to do with both the efficiency of the energy mixture, in terms of availability and environmental impact of the used fuels, and the energy efficiency in terms of reducing losses and saving energy resources.

The second goal, that a market is regulated to achieve, is improving the services provided to consumers. A characteristic example of the respective regulations, states that every consumer should be able to choose freely its energy supplier, choosing the level of quality of services and reliability willing to pay, and pay the appropriate price for it. In addition, the development of competition allows the offering of innovative products, closer to the needs and financial capabilities of each consumer. Another important service is the ability of the consumer to control the price of electricity that he pays, either by adjusting his consumption or through DR programs.

Last but not least is the environmental protection target that has been thoroughly regulated over the last years, changing the market conditions for all the participants. Two measures changed completely the landscape. The first on is known as Emission Trading System. Its aim is the internalization of the cost of environmental harm in energy production and consumption, leading to the gradual selection of new technologies, but in a manner that does not harm the economic development. The second measure refers to the so-called MERIT-order, in which during the dispatch of the units, all RES production has priority so that there is none left unused. This practically happens as RES bid with zero price. They receive income through a fix tariff that can last for up to twenty years. However, as the RES integration grows two things occur. Firstly, the thermal units, especially natural gas, struggle to remain competitive. Secondly, the RES production volatility increases creating imbalances and difficulty of forecast. To tackle this, following the well-known Target Model, RES are gradually facing penalties for their imbalances and also will bid as any other producer, receiving no priority in the merit order.

2.3.2 Monitoring the Electricity Markets

Any regulatory package or policy concerning the operation of electricity markets would be pointless if their implementation was not guaranteed. To achieve this, the electricity markets are constantly being monitored. Monitoring the markets works in favor of the prohibition of market manipulation. It is also responsible for guaranteeing the minimum disclosure requirements to maintain competition between the participants.

There some vital agencies organizations as far as the organization, policy and regulations of the European electricity markets are concerned, whose presentation is necessary for a complete understanding of the structure and functioning of the market. Every nation has its own national regulatory authorities or NRAs for every national market including the electricity. However as stated before in EU the goal is to succeed in a pan European electricity market, therefore NRAs are under the European Union Agency for the Cooperation of Energy Regulators (ACER). ACER is an independent body to foster the integration and completion of the European Internal Energy Market (IEM) both for electricity and natural gas [9].

Some characteristic regulations and directives are the Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT), MiFID(II), Competition Law: Articles 101-102 Treaty and the Directive 2003/6/EC on Market Abuse (MAD). All these regulations, laws and directives complement each other forming a robust framework for the proper operation of the market

2.3.3 The Third Energy Package

One of the most important pieces of EU legislation on European gas and electricity markets is referred to as the Third Package and is responsible for most of the aforementioned directives and regulations. It consists of three Regulations and two Directives and came into force on 3 September 2009. One of the primary aims of the Third Package was to further liberalize European energy markets. The Third Package designated the Gas and Electricity Markets Authority (GEMA) as the National Regulatory Authority (NRA), responsible for regulating Britain's energy market. NRAs are required to have regulatory independence and act independently of any market interests. They should not seek or take instructions from any organization, whether that is a state-owned or other public or private entity, when carrying out the regulatory tasks. The NRAs across Europe cooperate through the Agency for Cooperation of Energy Regulators (ACER), which was established under the Third Package to assist NRAs to perform their duties at EU level.

2.3.3.1 Unbundling

One of the core provisions of the Third Package, is ensuring that Transmission System Operators (TSOs) are unbundled (or independent) from generation, production and supply interests and are required to be certified as being so. The Third Package envisages that this unbundling will be effective in removing any conflicts of interests between producers, suppliers and transmission system operations. This will create incentives for necessary investment and guarantee access to new market entrants under a transparent and effective regulatory regime.

Cooperation between TSOs was also established through the European Network of Transmission System Operators for Electricity (ENTSO-E). An equivalent body was also created for gas (ENTSO-G). In addition, the Third Package encourages long-term investment by requiring ENTSO-G (and ENTSO-E for electricity) to publish non-binding Ten-year Network Development Plans (TYNDPs) every two years. The Third Package sets out obligations on suppliers relating to:

- customer bills
- the contents of supply contracts
- the length of time for which supply data must be retained
- the length of time it should take a consumer to switch their supplier (no more than three weeks).

2.3.3.2 Energy Infrastructure Package

The European Commission published its proposal for a Regulation on guidelines for Energy Infrastructure in Europe on 19 October 2011. The Regulation, which largely came into force in July 2013, covers both the gas and electricity markets and aims to ensure that strategic energy networks and storage facilities are in place by 2020.

The Energy Infrastructure Package (EIP) came about in response to the Commission's 2nd Strategic Energy Review published in November 2008. The review identified a need to enhance the existing Trans-European Energy Networks (TEN-E), highlighting that there was insufficient investment, lack of European coordination, no inclusion of innovative technological projects and lengthy procedures. Under the EIP, projects of common European interest will be selected by European Member States and the European Commission to fulfil particularly important gaps in European energy infrastructure.

Chapter 3: Literature Review

The present section is a literature review that focuses on two things. In the beginning, we touch upon the Spot Market of modern electricity markets. Specifically, we review the standardized products offered in a Day Ahead Market (DAM) and compare them with the ones in the original model. The review continues with the DR. Specifically in Demand Response, numerous DR programs and policies are presented, clustered and evaluated according to the recent literature. The present literature review constitutes the theoretical base, on which our new model emerges. The latter is explained and presented in Case description and modeling.

3.1 Spot Markets-The distributor point of view

As stated before SM plays a vital role in Electricity Markets, specifically in DAM. The DAM has a specific structure and way of operating that has not changed significantly the last years. The review of DAM will orbit around the standardized products available in the markets. This focus is important for the present research, as the original model (citation) uses two standardized products of the German SM.

3.1.1 Products

Focusing on European energy markets, there exist more than a couple of different products concerning the DAM. The most common, in almost every modern market, are hourly and block orders (CITE Nord, EPEX, IPEX, HEnEx etc.) [10] [11].

Hourly products are bids for sell/buy referring to a specific only hour of DAM. They are separated to Hourly Step Orders and Hourly Linear Piecewise Orders(cite EUPHEMIA). In general, hourly step orders refer to a specific amount of energy and a certain price limit. A buy step order will refer to a specific volume and an upper price limit that the buyer is willing to pay. Relatively, a sell step order refers to a specific volume and a lower price limit that the seller is willing to sell the energy. Hourly Linear Piecewise orders differ from step, as they do not bid specific price and volume of energy. Specifically they do bid a volume of energy that starts to be accepted after a specific price p_o until fully accepted at price p_1. These bids are called linear, as they do have a steady ratio between volume/price, therefore forming a linear order with a slope equal to that ratio.

An order is characterized as block order when it consists of a fixed amount and price of energy, referring to the same day and more than one time periods. However, block orders vary, providing different capabilities that suit different occasions of trading. According to one of the two largest Spot Markets in Europe, there exist four distinct types of block orders: Regular, Profile, Curtailable and Linked [12]

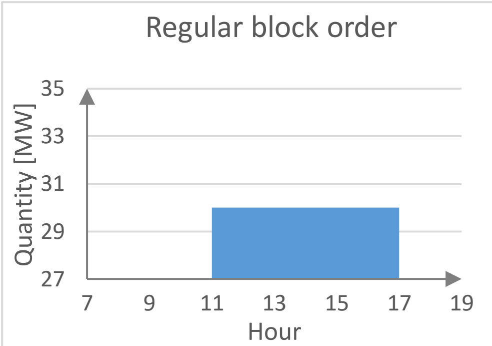

Figure 3.1 Regular block order

- <u>Regular block orders:</u> They refer to a specific time period and a fixed price for each of the included hours. These orders can be either sell or buy. Both must be either fully accepted or rejected by the market

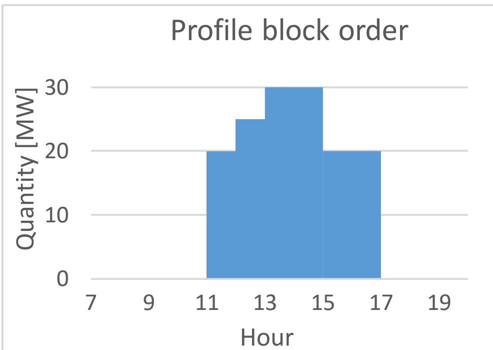

Figure 3.2 Profile block order

- <u>Profile block orders:</u> This category is very similar to the regular orders. The only difference is that they provide the ability to order different amount of power along each different hourly time slice of the time period of the whole block, hence creating a profile order.

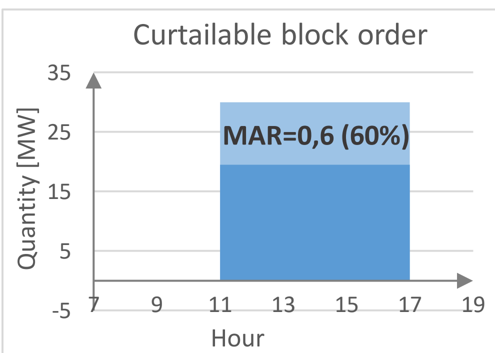

Figure 3.4 Curtailable block order

- <u>Curtailable block orders:</u> In contradiction to the previous two categories, curtailable block orders do not demand absolute acceptance or rejection. These orders are placed along with a Minimum Acceptance Ratio (MAR) that represents the percentage of the order that should not be curtailed. Therefore depending on the ,chosen by the bidder, MAR, an order can be completely curtailable, half curtailable, meaning that at least 50% must be accepted each hour of the whole duration of the block, or completely uncurtailable, hence equal to a regular block order that can either be fully accepted or rejected.

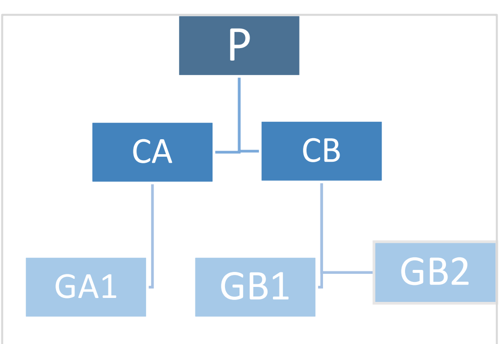

Figure 3.3 Linked block orders

- <u>Linked block orders:</u> Such orders consist of at least two blocks where the second is directly affected by the acceptance or refusal of the first. The first block is often called “father” or “parent” and can be linked to one or more distinct “child” blocks. Each of them can optionally have one or more “grandchild” orders. In Figure 3.3 Linked block orders, if the parent order is accepted, it will enable the two child orders CA, CB, and if any of them is also accepted by the market, will initiate the grandchild orders GA1 and GB1, GB2 respectively.

The above represent the most characteristic types of block orders. However, the customizability of the block orders is even greater, considering, that almost all the above types can be mixed, creating numerous hybrid block orders satisfying the different needs of the bidders. Internationally, there exist numerous exchanges but very few of them do integrate all different types of orders. Each market adapts to its custom needs, forming a specific benchmark of market products that sometimes are quite different in terms of specific hours, flexibility, curtailability, etc. [10].

Generally, the idea of block orders suits greatly the needs of power producers such as those of thermal powerplants that face significant start/stop costs. Specifically, without block orders, the optimal solution of any algorithm solving the electricity market, would result in unrealistic dispatch of thermal units. Research developed around EUPHEMIAS algorithm of the European electricity exchange, states that block orders indeed succeed in avoiding shut down of powerplants and realistic dispatch results [13].

The significance of the start up costs, and their implications in bidding in the SM, has attracted great attention among researchers and the industrial sector, resulting to detailed modeling in order to face the problem. Block order, and certain modelling constraints, can provide a solution to the problem. Also, the linked blocks provide the ability to bid a higher priced parent block, covering the start up costs, and a lower priced child block reflecting the lower operating expenses of the unit.

The distributor's portfolio does include a natural gas powerplant. However, the bidding strategy in the DAM is not in the scope of the present research. The different block orders and hourly products are presented to justify the available standardized products, which are also included in the energy portfolio. It is important from the distributor's point of view, which products would be available to him in the DAM, as the variety, flexibility and price of those directly affects the optimal solution.

3.2 Demand Response

DR is any method or program that tries to control the demand of electricity, from the consumer side, in order to optimize the system. This optimization can be of economical nature, such as incentivizing consumers to increase their load in off peak hours. Moreover, it can optimize the dispatch of the power generation units, or even reduce their environmental impact.

3.2.1 Classification of demand response programs

This subsection classifies and presents the numerous DR programs being considered for the electricity markets, based on some of the latest reviews. These programs can be generally separated based on the means used, in order to successfully manage the demand. The first group is known as "incentive based DR programs". This group of programs is based on the logic of providing the consumers with incentives that they are willing to participate in their load management, thus contributing to the efficient operation of the market. These incentives are mostly of economic nature. The other general group of DR programs has as main goal to discourage the consumption of electricity at times that would worsen the total economic cost of the market. This category is called "price-based DR programs" and discourages the consumption at specific periods through economic tools, such as pricing rates that vary throughout the day.

3.2.2 Incentive-based DR programs

It was mentioned above, that in this kind of programs, the consumers participating are offered compensation for each MWh that they curtail. This curtailment takes place mostly during the peak hours or specific events, scheduled or not. In this category do belong more than one programs, that although they share the above logic, they do have different characteristics. Among the most common and representative examples of incentive-based DR programs, are the Direct Load Control or DLC, Load curtailment, Demand bidding programs and Emergency demand reduction.

As far as the DLC is concerned, it requires the registration of every consumer that will participate. The participants give the right to the responsible entity of the DR to shut down any of the electric devices included in the contract. Such programs refer mostly to the control of residential devices throughout the peak hours. Simply put, these programs provide the responsible DR utility, with the capability of shutting down specific electric devices among the contracted consumers [14] [15] [16].

Respectively, in load curtailment programs, the contracted consumers are incentivized to allow the utility to shut down their electric devices. However, these programs have a noticeable difference compared to DLC. Load curtailment programs do give the ability to each contracted consumer to deny the specific curtailment, facing nevertheless sever penalties [17].

In contradiction to the above two DR programs, demand bidding operates in the logic of a market by creating competition among the bidders. In these programs, contracted consumers of DR are not obliged to curtail their loads or be penalized, but they are making offers to the utility to curtail their loads. This requires a great understanding and information about the price of electricity from the side of the consumer. For this reason, such DR programs refer mostly to large-scale consumers or to DR aggregators which have their own DR portfolios, consisting of residential or other consumers. The existence of DR aggregators in electricity markets creates new possibilities, especially regarding the energy trading. DR aggregators utilize their portfolio of DR consumers to maximize their earnings through bidding the curtailment of energy. Therefore, other utilities can operate as DR aggregators too, integrating the DR bidding in their trading procedures. Such examples are described in many researches [18] [19]. Literature wants DR aggregation participating in liberalized markets to be significantly profitable for the aggregators and passing partially profits to the end consumers as well [20].

As far as the emergency demand reduction programs are concerned, they follow the simple logic of providing economic incentives to consumers in order to reduce their consumption when severe contingencies occur. These programs are for extreme situations, where a blackout is about to occur if no action is taken.

3.2.3 Price-based DR programs

As stated before, the second group is the price-based DR programs, which instead of providing economic incentives to the consumers, they do have a dynamic pricing of the electricity used. In this group belong four characteristic kinds of DR programs. The first one is called Time of Use or TOU pricing, the second Critical Peak Pricing (CPP) and the last Real Time Pricing (RTP).

TOU pricing is separating the day hours into specific periods. In each period the utility is pricing the consumer consumption with a different electricity price. Most of the times these periods follow the same logic with the DAM, separating the day into off-peak hours, peak-hours and mid-peak hours. Doing so, the utility or DR aggregator is not curtailing any of the consumption but is actually incentivizing the consumer to avoid higher consumption during peak and mid peak hours [21] [22] [23] [24] [25]. Similar to TOU is also the CPP, which has as only difference the occasion of extreme events threatening the reliability of the power system. Once this happens, CPP increases dramatically the prices to discourage the consumption of electricity.

One of the most popular DR programs is the RTP. The logic of RTP is similar to the TOU. However, instead of separating the day in three or four periods, the RTP has an hourly pricing system. This means that the aggregator is providing the consumer with an hourly price curve just like the DAM. Here, the attention is brought to the way of informing the consumer about the price. In markets where the DAM is published, like the case of Greece, consumers are informed on a day ahead basis. In other cases where this is impossible, there can be an hour ahead notification along with a day ahead price prediction [26] [27] [28]. However, this method requires considerable technical installments such as smart meters and communications between the consumers and the utility.

Finally, IBR programs share also the same logic with TOU, by having discrete pricing periods. However, this time the different pricing does not depend on the time period but on the aggregated consumption. Specifically, there is a specific threshold of kWh, that when reached the electricity price is significantly increased [29] [30]. Such programs are being implemented over the last forty years.

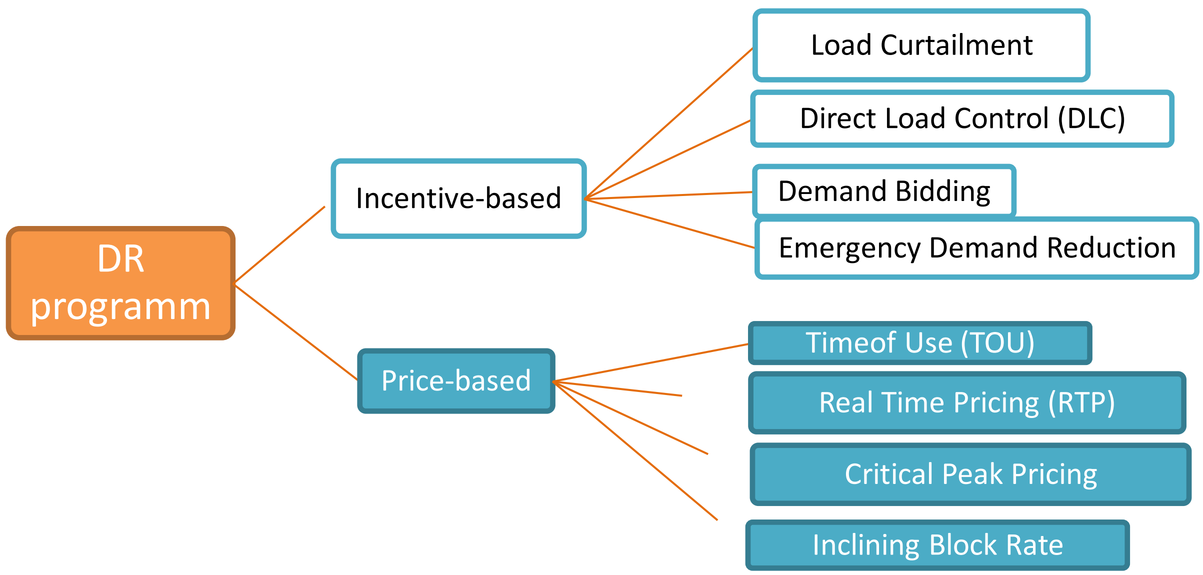

Figure 3.5 Classification of DR programs [31]

3.2.4 DR Technologies, Costs,

Following the above review of the most characteristic DR programs, the present subsection presents some of the required technologies along with the respective costs for DR implementation. Different DR programs refer to different consumers as seen above those might be households, big industries or commercial. However, no matter the consumer, both “incentive-based” and “price-based” DR programs require the installation of technical devices at the consumers electric systems. These smart metering technologies consist of digital meters, metering the consumption, storing historical data etc. The data gathered must be sent then to the utility through a network system. This network is also responsible for sending data from the utility to the consumer such as the control of the electric devices to turn on/off, or in the case of “price-based DR” the required day ahead prices or forecasts [32].

Therefore, the consumer willing to participate in DR programs should bear in mind the cost of the above costs as well as the possible costs of an “event”. Moreover, household consumers are found to participate more in DR programs than industrial or commercial consumers [29].However, in absolute terms, the industrial and commercial consumers participating in DR programs, provide greater loads for curtailment, as a result of being more energy intensive operations.

3.3 Consumer behavior affecting the DR programs

Many curtailment surveys consider consumer involvement as a given. Such a view is unrealistic, leading to unrealistic results. Some research into the intention of consumers to participate in such programs shows that different consumers have a different degree of engagement.

For a consumer that its electricity expenses constitute 10% of the total monthly expenses, the perception over DR programs is quite different compared to a consumer that electricity is the main source of expenses. Therefore, literature shows that electricity intensive industrial consumers tend to engage far more to DR programs than the least electricity intensive industries. Another characteristic of the consumer profile that engages more in DR, is the flexibility of its operations. Simply put, it is quite different for consumers such as commercial to shift their loads outside of peak hours because this are the only hours they operate during the day. Such practical constraints affect significantly the engagement of specific consumers [33].

Moreover, the education around DR programs and their benefits plays an important role especially for residential engagement. The gap between the academic sector and knowledge and the knowledge of the “common people” might downgrade the benefits of DR. It is important for utilities to organize campaigns for educating and informing the public about the different DR programs and their advantages and disadvantages. Additionally, the best solution from a modeling and economical perspective might not coincide with the one that provides the greatest engagement. The consumers may not be willing to understand and participate in complex operations such as DR bidding or real time prices RTP. Therefore, the simplicity and consumer friendliness of each DR program might play a greater role than the overall cost minimization [34], [35]. Taking under consideration, the U.S. Electric Power Research Institute (EPRI) recommends breaking down the consumer engagement in three levels: participation, response and persistence [36]. The first two are clear after the above presentation. The third level refers to the loyalty of the consumer remaining in the DR program or breaking the contract.

Chapter 4: Case description and modeling

In this chapter, we describe the problem and the modeling of it. Since our model is based on the original model [37], it was considered appropriate to present the problem in the same way and maintain the same variables, so that the differentiation and evolution of the present model was evident. This way the reader-researcher will be able to compare the new models more easily with the original one.

The case scenario refers to an electricity provider, referred as "distributor" in the original model, responsible for meeting the demand of its customers. It is hypothesized that the distributor knows the specific energy demand of the Day Ahead (D+1). The demand forecast is a table of quarterly forecasted demand in MWs for the next 24 hours and consists of a continuous function.

$$P(t)\,, \qquad 0 \leq t \leq 24 \tag{1}$$

Where: $P(t)$ is given in MW and represents the curve of power demand
t symbolizes the hour of the day

The original case separates the day ahead demand from hourly to quarterly resolution, mentioning that such a frame constitutes a common standard in many electricity systems. Therefore:

$$T := \{1, \dots, N^T = 96\} \tag{2}$$

$$P_t \quad , \quad t = 1, \dots, N^T \tag{3}$$

Where: T is the set of quarter-hour time slices per day
P_t is given in MW and represents the day ahead demand in quarterly frame
t symbolizes from now on the quarters of the day ahead

The present research's scope does not include the methods, or the technical means required in forecasting the Day Ahead demand. However, such a forecast is not difficult, because it refers to a specific consumer portfolio. The specific group of consumers whether industrial, commercial or residential, constitute a specific energy demand curve. This demand can be accurately forecasted through historical data, considering any existing seasonality, trends and "events".

Knowing the D+1 electricity demand, $\boldsymbol{P_t}$ the provider must provide all the electricity asked, leaving none of the demanded capacities unmet. This means the model considers 100% demand coverage as a prerequisite and constitutes one of the initial constraints. To do this, the distributor has more than one means in its disposal.

The first option is a natural gas powerplant in distributor's possession. The powerplant does operate however the distributor decides, always under the technical constraints such as start and stop times etc., and will be presented in detail in Modeling the Power-plant. The decision of this kind of powerplant was taken due to two different reasons. Firstly, the same unit was considered in the original model, and therefore helps to preserve the comparability between the original model and the new one developed in this research. Secondly, natural gas fired powerplants are a technology that is expected to continue to operate for the next years, having a pivotal role along with RES in the gradual removal of lignite powerplants.

The second option in the distributor's disposal is obtaining the required energy from the Electricity Market. The case refers only to short term operations of the distributor, therefore any activities in the market regarding the Spot Market (SM), and specifically the products of DAM. This means that long term products such as forwards or bilateral etc. are disregarded, focusing only on a D+1 optimization model. The specific products available, and the capabilities of the distributor in regarding the SM, will be thoroughly discussed.

The third and last option is controlling the demand. This option is used when the energy obtained from the other two, powerplant and SM, is incapable of meeting completely the demand. Incapable of meeting the demand does not mean actual physical incapability, but economic preferability. To clarify this, covering the demand in peak hours using only the first two options, might be more expensive for the distributor than making use of the third option as well, to cover part of the demand.

Controlling the demand is known as Demand Response (DR) and can be executed in different ways. This option can be very helpful, especially in peak hours or in "events", by curtailing the excess in demand or shifting the load to other time periods. Such capabilities can also be used for avoiding extreme price peaks or downs, thus increasing the markets stability by decreasing volatility. However, this option does have the drawback of preventing the use of energy for specific types of use and specific time periods, reducing the consumer's freedom. The interaction required between the distributor or any other responsible for the DR and the final consumer raises, numerous challenges. The different existing DR programs, along with their advantages and the arising challenges, can be found in Demand Response of the Literature Review.

Below is presented the DR program used in the original model, originally referred to as Load Following Contract (LFC). Taking under consideration the results and conclusions of late DR research focusing on reliability and consumer engagement, an enriched version of the initial LFC is presented below.

The purpose of the research is to provide the distributor with the optimum scenario. The solution is optimizing of the mixture of the three options in order to meet the demand with the minimum cost.

4.1 Modeling the Power-plant

As stated in the introductory part of this section, the distributor has the ability to produce power from a natural-gas fired powerplant.

Let the maximum power output of the power plant equal to 300 MW.

$$P_{max}^{PP} = 300MW \tag{4}$$

During normal operation the powerplant should not be operated at less than 40% of the maximum capacity. Therefore:

$$p_t^{PP} \geq 0.4 P_{max}^{PP} \ , \ \forall t \ , \tag{5}$$

Where: p_t^{PP} represents the output capacity of power in MW of the power plant at time period t.

In case the powerplant is not used, then $p_t^{PP} = 0$. Moreover, the powerplant must operate in specific steps meaning that its power output does not follow a continuous curve but is rather a step equation. Specifically, it can operate in eight, including idle stage, different stages.

Operating Stage	Output Capacity (MW)
1. Idle	0
2. 40% of max. capacity	120
3. 50% of max. capacity	150
4. 60% of max. capacity	180
5. 70% of max. capacity	210
6. 80% of max. capacity	240
7. 90% of max. capacity	270
8. 100% of max. capacity	300

This is mathematically translated to the following equation substituting eq. (5):

$$p_t^{PP} = 0.1(a_s + 2) P_{max}^{PP} \ \ , \ \forall t \ , \tag{6}$$

Where: $a_s \in \{2,3,4,5,6,8\}$

Apart from the power output steps, the powerplant does have another techno-economical constraint. As stated before, the start up/shut down cost of thermal units plays a significant role in their operating expenses. Therefore, it cannot be excluded from the model. To integrate this technical constraint would require a specific minimum operation period of the powerplant. However, such a constraint is incomplete, because it allows the powerplant to change power constantly from one step to the other. To avoid this, we follow the original modeling of "poutil" by constraining each power output level to operate a minimum period of two hours before changing. This is modeled as:

$$D_{act}^{PP} = 8 \tag{7}$$

Where: D_{act}^{PP} is the duration of each power level measured in quarters

Now we can add the constraint regarding the minimum idle time of the powerplant to be at least four hours, such as

$$p_j^{PP} = p_{j+1}^{PP} = \cdots = p_{j+m}^{PP} \quad , \quad \text{with} \quad m \geq 15 \ , \tag{8}$$

Where j is a time interval containing an idle time

Most of the modelling of the powerplant can be found in the original article [37], therefore the rest of the modeling section will present only the additional modelling that was made to create the two new models, "Flexible PLCs" and "Fully Integrated".

4.2 Modeling the Spot Market

The distributor can not only produce power through the power plant, but also buy from the Spot Market (SM). In the original model, the SM does provide two different standardized products, Base Load and Peak Load Contracts, BLCs and PLCs respectively. The BLC is the purchase of a specific amount of power (MW) for a duration of twenty-four hours. The total amount of energy bought from a BLC is the product of power bought (MW) multiplied by twenty-four hours, which is the BLC duration. A PLC is the purchase of power referring only to peak hours (08:00-20:00).

The new model integrates the ability of the provider to participate more actively in the SM, being able to purchase two additional PLCs of smaller duration, as well as hourly products that are available in every electricity market these days.

4.2.1 Improving the Peak Load Contracts

The Spot Market of the initial model does provide one 12-hour PLC from 08:00-20:00 and a 24-hour base block product. The price of PLC is obviously higher than the BLC, as it refers to a smaller time period of greater demand when more expensive power units are called in order to satisfy the demand. However, these two block products from the SM do not optimize the flexibility of the market. For example, in order to meet the peaks of the demand at the Peak Zone, the distributor can only buy 12-hour PLCs, and cover any incapability of energy delivery through Load Following Contracts (LFCS). LFC is mostly known as Demand Response and is the most expensive choice. A short review about pricing the demand response lays in Demand Response.

From the demand side, for an average day of the year, there exist specific periods where power demand is greater than the rest of the day. These periods known as peak-hours, could raise the power demand even by 188% in the present case of the model. However, this growth is not gradual, neither the demand remains constant after reaching an upper maximum. The continuous fluctuations of the demand, especially during the Peak Zones, underline the absence of smaller, hence more flexible, PLCs. The above problem can be perceived from the supply side through the DR, which are increasing dramatically whenever the demand rapidly rises and are presented in detail in . For example, the additional demand in peak hours would be covered by LFCs and not PLCs, because the marginal cost of an additional MW through a 12-hour PLC would be greater. Reminding at this point that the distributor is incapable of producing additional power from the natural gas plant as it is already running at maximum capacity. Based on the above, having the ability to buy smaller-flexible PLCs, a distributor might reduce the amount of MW "bought" from LFCs, which are paid to the final customers for reducing their consumption.

4.2.1.1 Pricing the different PLCs

The original model that our research is based, does not integrate the ability of buying all the standardized products of the SM. Without such a product, any hourly demand peak cannot be efficiently satisfied by the original BLC and PLCs, not even from our flexible PLCs. In the original model, any demand peak of such is covered through Demand Response, having none constraint over the maximum energy or power that can be curtailed.

Therefore, the PLCs therefore emerge as a mean of reducing the overall cost by substituting part of the expensive LFCs. For this reason, pricing the new PLCs is of great significance, as it directly affects the optimal solution. Further explaining this correlation between PLCs and Demand Response(DR), if the PLC price approaches that of a Demand Response, then the distributor will not have enough motive to buy power from a PLC instead of the more flexible LFC. On the other hand, if a PLC is cheaper than an LFC, to counterweight being less flexible, then a distributor would choose the first, not constraining the natural demand of the final customers through LFC.

This section of the research does present two ways of pricing the new PLCs. The first one is by a draft regression based on the data of the original model, "poutil". The second one is re-pricing all the products (including the BLC and PLC of the original model), based on the new hourly day ahead prices that we integrate.

The latest addition of hourly products, as in any Day Ahead market, cannot be dealt respectively to the flexible PLCs. Inserting the capability of hourly power purchase in the Day Ahead requires also the price curve . The distributor in our model has to operate as any other player of the Day Ahead market, and forecast the DA price. The differences between the forecasted and the real price are of no concern in our model, as they are covered either through Intraday or balancing markets. Following on from the above, the distributor does bid in the Day Ahead Market quantities that remain to be satisfied and cannot be covered by the powerplant production, or are more economic than the block products of the SM.

Between the two methods, we chose pricing based on the new hourly products, as it is more robust and reassures the integrity of our numerical results. However, the first method is also presented in the sub-section below.

4.2.1.1.1 Pricing based on the original model

In this subsection we consider the importance of comparability between the old “poutil” (original) model and the “Fully Integrated” that we propose. One way of dealing with this, is pricing the new 4 and 2-hour PLCs proposed based on the exact prices of the “poutil”. In the latter exist only two products in the SM, the BLC and PLC, and the DR referred to as LFC.

Starting with the BLC and PLC, the different pricing of the two is observed and equals C^{BL} and C^{PL} respectively. The price is higher for the 12-hour contract, as it refers to the Peak hours, and includes more risk than a 24-hour for a wholesale supplier wanting all its produced energy sold. Following the same logic, we could expect that, the smaller the duration of a PLC the higher it’s price should be.

In order to make the new model comparable to the original, the smaller PLCs will be priced based on the prices of the original model, which are presented below:

Product	Price €/MWh
BLC	32
12-h PLC	41

Table 2: Products and prices of the original model

Observing the hour and cost difference between the BLC and the PLC of the original model, can produce a cost equation that gives the price [€/MWh] of different duration PLCs. Using these two pairs of data can only produce a linear equation between C^{PL} and the PLCs duration Δt_{PL}. Modelling the ideal PLC price equation is not the main purpose of the present research. Nevertheless, a linear equation is improper. An exponential, or a second-degree polynomial equation will be suitable, but they do require at least three different pairs of data. In order to maintain the comparability between the two models, the third pair of data could be the price of the Demand Response (LFC in the original model). At this point, it should be reminded that the Demand Response does have three different prices, depending on the amount of power that has already been bought through LFCs in Pricing the DR program. Specifically, there exist three price zones Z1, Z2 and Z3, hence there are three different data pairs to choose as the missing data in order to produce the price equation. At each of the three figures on the side, there are presented different equations that arise from the different data sets, as well as from the different regression methods: linear, exponential and polynomial of second degree.

Although each of the three different regressions do have relatively satisfactory coefficient of determination R^2, the second order polynomial is the most appropriate. This selection could be of great importance, as it directly affects the preferability of a PLC over a LFC, by determining the PLC prices.

At first, we assumed two different regression methods: polynomial and exponential. Moreover, as stated before, a third pair of data (x3,y3) is required for a proper regression. The third pair of data emerges from the Demand Response price referred to as LFC in the original model. The LFC price has three stages 80, 65 and 52 €/MWh, hence producing a total of six different equations. At the side figures, we chose to present the equations emerging from the lowest possible price of the Demand Response.

Plotting the above equations brings into view significant differences between them, which make the selection of the most appropriate a priority before incorporating the new PLCs to the model. Such differences are significant because PLC prices affect directly the amount of LFCs and PLCs bought by the distributor. Therefore, the optimization of the cost of energy purchase through the SM.

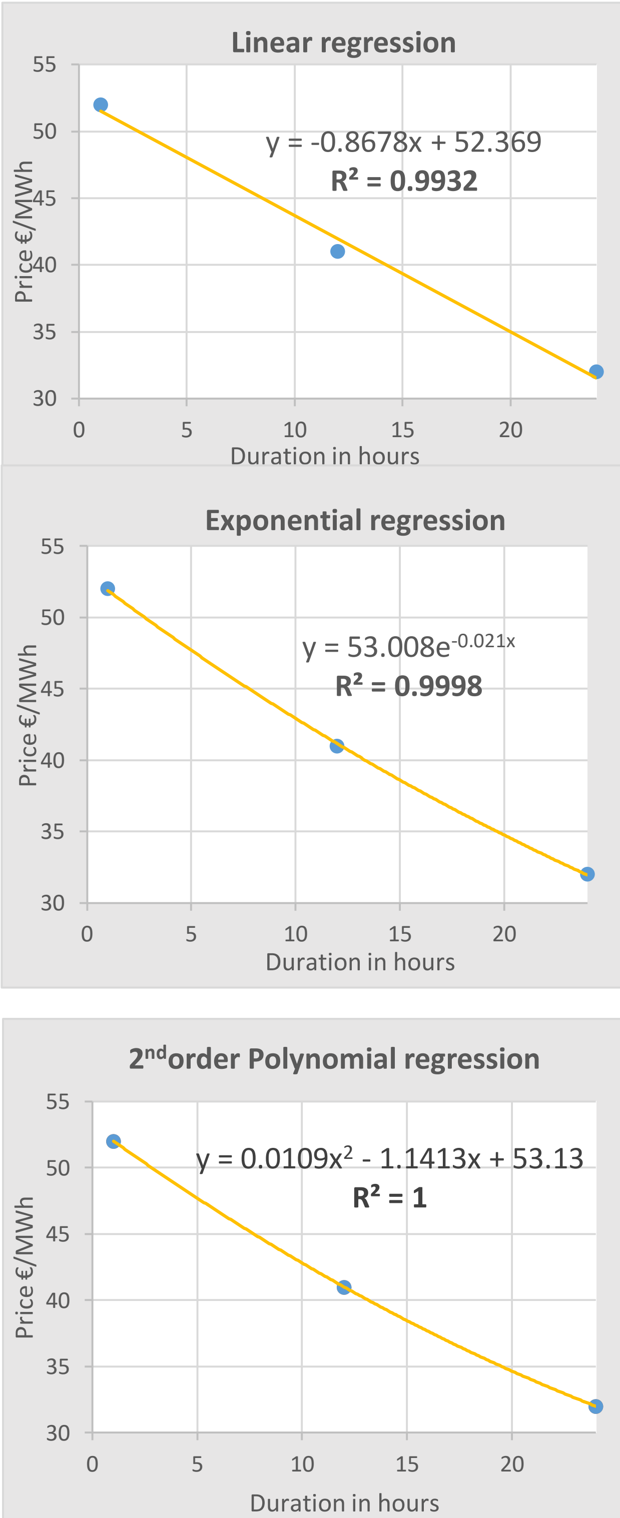

Figure 4.1 where y: the LFC price in €/MWh
x: the duration of the contract in hours
R2: the coefficient of determination

	12-hour PLC	4-hour PLC	2-hour PLC
a	08:00AM-08:00PM	8:00AM-12:00PM	8:00AM-10:00PM
b	-	12:00PM-4:00PM	10:00PM-12:00PM
c	-	4:00PM-8:00PM	12:00PM-2:00PM
d	-	-	2:00PM-4:00PM
e	-	-	4:00PM-6:00PM
f	-	-	6:00PM-8:00PM
Price €/MWh	41.0	48.7	50.9

Table 3: The different new flexible PLCs

Based on the above various scenarios, additional PLCs can be considered. The different scenarios of PLCs are dividing the 12-hour PLC to smaller sub-periods. It is believed that this will increase the flexibility of a distributor when purchasing energy from the Spot Market, especially when Peak Energy Demand occurs. Without the new flexible products, long duration PLCs oblige the buyer for big time periods, where the demand fluctuates. Therefore, the distributor might reduce the amount of PLCs, and use Demand Response when peak demand occurs. Consequently, coexisting smaller duration PLCs could provide more flexibility and reduce the amount of curtailed demand. This is presented in Results.

Starting by inserting a new PLC of a duration smaller than twelve hours, we compare the new overall cost to the one of the original model. The selected PLC is that of four hour duration, 4-hour PLC and as presented in Table 3, splits the twelve hour peak load into three different sub-periods. The 4-hour PLC in the new model is additional to the existing Spot Market Contracts, meaning it does not exclude the previous contracts BLC and PLC.

The new SM of the model consists of three different Energy Contracts, exactly the same as previously, where the model included an additional 4-hour PLC. The only difference this time is a 2-hour PLC instead of 4-hour. Below is presented the model with the additional 4 and 2-hour PLCs.

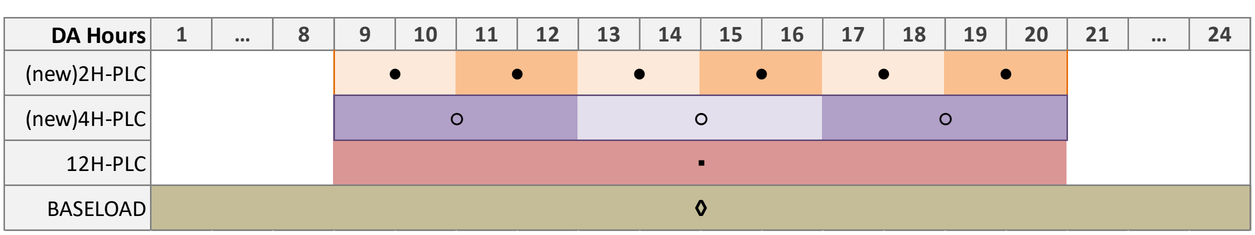

Figure 4.2: All SM products with the additional 4 and 2-hour PLCs

The optimization model will always choose the more economic option, as long as the demand is completely satisfied, thus deciding each time which of the three overlapping PLCs (12-,4- or 2-hour) achieves the greatest reduction to the overall cost. The creation and integration of all three different PLCs to the model, is thoroughly presented below. It is important to remind that the present method of pricing based on the prices of the original model, is not actually integrated in the final model, as a better solution was found. The next sub section presents the integration of new hourly products and the new pricing of all the SM.

4.2.1.1.2 Pricing based on the Hourly Prices

In the present subsection, we present the pricing of all the SM products based on the new hourly prices, and not on the original prices of the model "poutil". As explained above, this is the method used in the optimization model, as it provides trustworthy results. To price the products based on the hourly prices, we must first choose which hourly prices to integrate.

The present research uses hourly prices of the Hungarian Energy Exchange, HUPX. HUPX is the most developed energy exchange in SEE, and constitutes the Spot Price for many countries such as Serbia, Albania, F.Y.R.O.M. and others. Specifically, the prices belong to a random week-day of March 2020 and are presented in the next chapter Table 5.

The whole 24hours constitute the Baseload. The twelve hours 8AM to 8PM constitute the Peak Load. Respectively, the pricing of the new flexible PLCs of 4&2 hours, is actually the average price of the respective hourly prices. The below Figure helps in understanding the relations between the SM products and the Hourly Prices.

<table>
<tr><th>DA Hours</th><th>1</th><th>…</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>…</th><th>24</th></tr>
<tr><td>(new)Hourly</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td><td>×</td></tr>
<tr><td>(new)2H-PLC</td><td></td><td></td><td></td><td colspan="2">●</td><td colspan="2">●</td><td colspan="2">●</td><td colspan="2">●</td><td colspan="2">●</td><td colspan="2">●</td><td></td><td></td><td></td></tr>
<tr><td>(new)4H-PLC</td><td></td><td></td><td></td><td colspan="4">○</td><td colspan="4">○</td><td colspan="4">○</td><td></td><td></td><td></td></tr>
<tr><td>12H-PLC</td><td></td><td></td><td></td><td colspan="12">▪</td><td></td><td></td><td></td></tr>
<tr><td>BASELOAD</td><td colspan="18">◊</td></tr>
</table>

Figure 4.3 All the products of the SM in the "Fully Integrated" model

The products of the above figure are priced as the numerical averages of the respective hourly prices. The actual complete SM costs of all the products can be seen in Table 5.

It is important to notice that in contrast to the BLC and 12-hour PLC, the 4 and 2-hour PLC do not constitute a single contract, but three and six respectively. These contracts have also different prices. This means that these products do introduce two new characteristics-options in our model. Firstly the smaller PLCs, as stated, provide greater flexibility to the distributor, giving him a greater resolution to its energy bought from the SM. Secondly, having mentioned the price difference between same products of different time periods, the model integrates the logic that pricing is affected, not only by the duration of the product, but also of the specific time that this product is used. This is exactly the reality of the markets and the reason we integrate an hourly product to the model.

Although the scope of the present research excludes the consideration of any trading-bidding strategy for the energy bought through the SM, a provider of the modern electricity market should be able to participate more actively in the Spot Market. Therefore, without getting into trading details and modelling, the integrated model includes hourly products, as well as flexible PLCs that share the same pricing philosophy.

Based on the above, having concluded in the integration of all the products (hourly,2-hour PLC, 4-hour PLC,12-hour PLC and BLC), we hereby present the mathematical modeling. Starting with the power from the SM, we move directly to the new additional equations of the new models.

$$p_t^{SM} = \alpha + I_t^{12HPL} \cdot \beta + I_{it}^{4HPL} \cdot \gamma_i + I_{jt}^{2HPL} \cdot \gamma_j + I_k^H \cdot \gamma_t \tag{9}$$

Where: $i \in \{1,2,3\}$, $j \in \{1,2,3,4,5,6\}$, $k \in [1,24]$

p_t^{SM} is the power curve of the quarterly power from the Spot market

α, β are the number of BLCs and twelve-hour PLCs respectively in MWs

$\gamma_i, \gamma_j, \gamma_t$ are the number of four-hour PLCs, two-hour PLCs and hourly products respectively in MWs

I are dyadic indicators of specific time periods

k is an integer

The above equation represents the power coming from the SM each quarter. It is equal to the notional amount of power coming from each product of the SM. Starting with the power from BLCs, as they refer to the entire twenty-four hours of the day ahead, the power is fix for any time slice, *t*. The 12-hour PLC is also providing fixed amount of power for the entire peak load period. However, the model must know when we enter the peak load time period when the PLCs are available. Therefore, the dyadic indicator I_t^{12HPL} indicates when the time slice t belongs in the peak zone by changing its value to 1, and equals 0 when outside of the peak load time period.

The same situation exists for the four and two hour PLCs. The only difference compared to the 12-hour PLC, is that the flexible PLCs do not have fixed power throughout the peak load time period. The flexible PLCs can have different power volumes, as there are three and six different 4-hour PLCs and 2-hour PLCs respectively. Therefore, exist different variables of power γ for each of the twelve distinct flexible PLCs (three 4-hour PLCs and six 2-hour PLCs). The same goes for the dyadic indicators *I*, which state if the time slice belongs in the specific flexible PLC or not. For example:

$$I_{1t}^{2HPL} \cdot \gamma_1$$

Gives the quarterly power coming from the first 2-hour PLC, and the dyadic indicator will equal 1 for the respective time period of the first, out of the six, 2-hour PLCs. Moreover, the dyadic indicator I_k^H indicates at which specific hour the *t* belongs.

The same logic is followed for creating the respective cost equation of the SM. Specifically, the cost is equal to the amount of power from the SM, multiplied by the respective power price. The original model "poutil" does not provide a quarterly distribution of the cost of the power from the SM, but only the total cost for the day ahead. Therefore, the total cost of the "Fully integrated" model, is calculated based on the below equation:

$$C^{SM} = C^{BL} \cdot \alpha + C^{12HPL} \cdot \beta + \sum_t C_i^{4HPL} \cdot \gamma_i + \sum_t C_j^{2HPL} \cdot \gamma_j + \sum_t C_k^H \cdot \gamma_t \tag{10}$$

Where: C^{SM} is the total cost the provider pays for buying power from the SM

C^{BL}, C^{12HPL} are the costs for one MW(contract) of the BLC and the 12-hour PLC respectively

C_i^{4HPL}, C_j^{2HPL}, C_k^H are the quarterly cost of each flexible PLC and the hourly product respectively

The present research does also calculate the total SM cost of the two new models considered, and compares it with the original. However, the quarterly cost curve is created and presented in the Resultsas it shows in detail the cost minimization achieved by our models compared to the original.

4.2.1.1.3 Hourly Products and Flexible PLCs under increased Volatile Demand

The case in our model remains the same as the original one, where the distributor knows the day ahead energy demand. This demand is the quarterly energy requirements of the distributor's consumer portfolio. In Figure 4.4, the first column represents the actual quarterly demand of the consumers.

It can be seen that the demand is rationally following the daily requirements of a homogenized consumer portfolio. However, an optimization model must be effective in different customer portfolios. A portfolio with more household consumers will certainly have a different demand curve than a portfolio with less households and more industrial consumers. Additionally, the consumer profile does change through the ages, due to new trends and commercial technologies.

A characteristic example of such is the emerging capability of consumers to produce their own energy, known as pro-sumers. Such new trends, along with the different possible consumer mixtures, (household, industries etc.) do underline the changing nature of the demand curves. Therefore, the "Fully Integrated" model assumes a more volatile demand than the one assumed by the original model.

Reminding that the present research wants to remain comparable to the original model in order to underline the further optimization achieved, changing the energy demand volatility must respect this. Therefore, the new demand equals to the original in terms of total amount of energy (MWh) and consequently average value (average hourly demand), but differs at the standard deviation, which now equals 92.69, when originally it was 62.88. The new increased volatility demand can be seen in the following diagram.

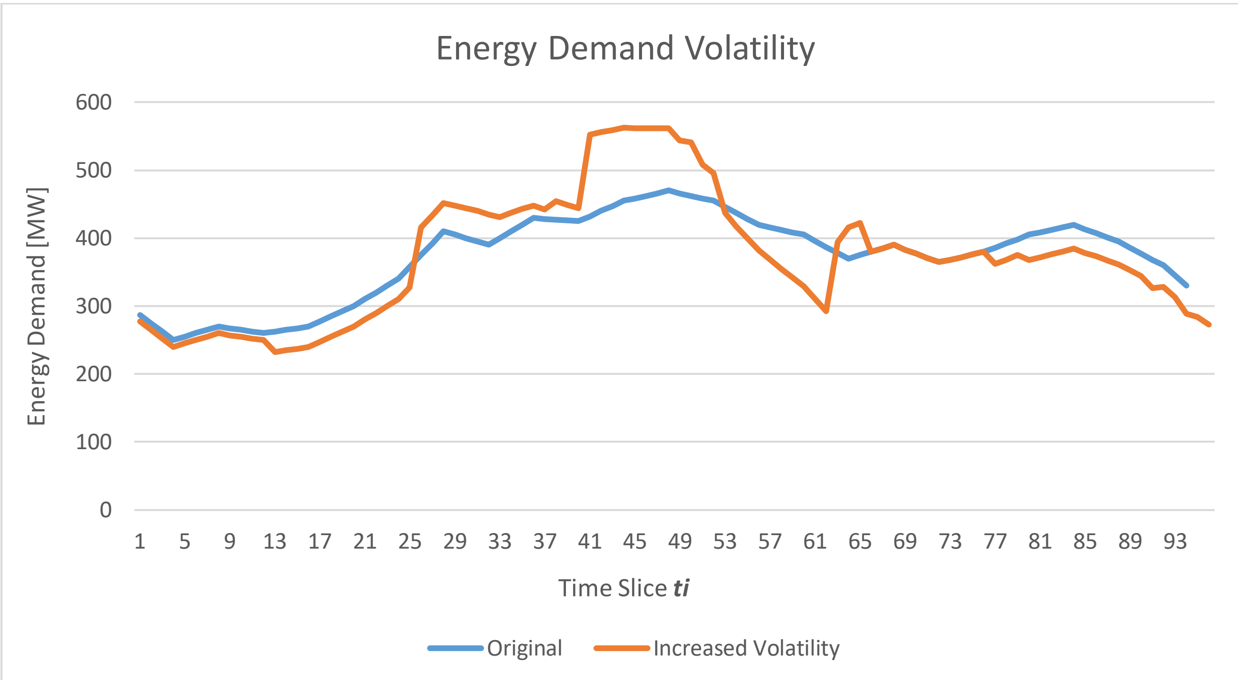

Figure 4.4 Energy Demand Volatility

It is noticeable that the volatility of the new artificial demand is increased mostly between time slices ***ti*** (33,66). This happens because our interest is to demonstrate the importance of flexible PLCs and the hourly products, in reducing the overall cost, especially in volatile demand scenarios. therefore the volatility is artificially increased, mostly during the Peak Load period ti(33,80), when the PLCs are available.

4.3 Modelling the Demand Response

Demand Response has attracted a lot of attention, as said in the introduction of the thesis. A clustering of the many different DR programs available in the modern markets takes part in the Literature Review section. An important factor, that directly affects the success of any DR program, is the rate of response from the consumers. As seen in Consumer behavior affecting the

DR programs, the response rate differs strongly among the numerous DR programs, with DLC and TOU being the most efficient.

The two new models, "Flexible PLCs" and "Fully Integrated", integrate the same DR program as the original model "poutil". However, the nature of DR is such, that a short presentation of its modeling is helpful. The DR presentation serves also the integration of a new constraint regarding the DR, which is explained below after the modelling of the DR price zones.

4.3.1 Pricing the DR program

It should be clear by now that DR, and specifically the power curtailment through LFCs, is in general the most expensive mean of meeting the demand. Regardless of the specific additional cost in €/MWh, DR should be the most expensive mean, in order to incentivize the distributors of further optimizing their operations, and secure **consumer welfare** through other means and not by curtailment. Another logical explanation is that due to its quarterly resolution, LFC is the most flexible compared to the rest available means of the distributor (powerplant, SM), for meeting the demand. The quarterly resolution is visible in most figures in the results chapter.

The initial LFC implemented in "poutil" belongs in the DLC category of DR programs and remains an efficient way of controlling the demand in peak hours. The suitability of this program is based on the findings of the Literature Review,which want simpler DR programs in order to achieve greater consumer engagement [34].

The price of the DR is not fixed, but changes according to the level of curtailability. Specifically, the pricing is divided in three distinct zones of aggregated curtailed energy. The provider keeps track of the curtailed amount of energy of the entire year, and follows an annually based priced system, with the aforementioned zones. The prices are the incentives paid to the consumers, hence they are equal to the cost the provider bears for the curtailment.

Let Z_1, Z_2, Z_3 be the volume boundaries of the three annual price zones in MWh. Then, the below figure presents the exact values forming the respective zones.

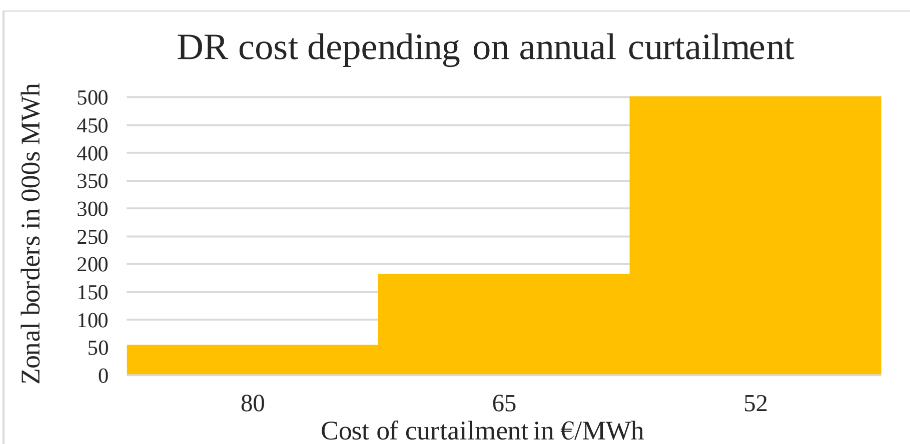

Figure 4.5DR Price Zones [38]

However, the model is working on a day ahead basis, therefore the annually based price system is improper. As in “poutil”, to overcome this, we transform the annual zones to daily ones. This can be easily done by diving the zone values Z_1, Z_2, Z_3 by the number of days constituting a year.

$$Z_1^d = {}^{Z_1}/_{365}\ ,\ Z_2^d = {}^{Z_2}/_{365}\ ,\ Z_3^d = {}^{Z_3}/_{365} \tag{11}$$

Where: $Z_1^d,\ Z_2^d,\ Z_3^d$ are the respective daily zonal borders in MWh

The below table represents both the annual zonal borders and the daily zonal borders with the respective prices.

DR Zonal Price € /MWh	Annual Zonal borders MWh	Daily Zonal borders MWh
80	54750	150
65	182500	500
52	max	max

Table 4 From annual to daily DR cost zonal pricing [37]

The cost of the curtailed energy that the provider must bear is calculated by the following equation:

$$c_{ER}^{DR} = \sum_{b=1}^{N^B} (C_b^{DR} \cdot \mu_b + \ P_b^{DR} \cdot e_b^{DR}) \tag{12}$$

Where: c_{ER}^{DR} is the total cost for the day ahead DR
C_b^{DR} is the accumulated cost up to segment b
μ_b is an indicator of the DR zonal prices
P_b^{DR} is the zonal price
e_b^{DR} is the contribution of the total energy curtailed in the specific segment b
b is the segment indicator
N^B is the total number of distinct price zones/segments

From the above equation, we get that the total cost of the DR is equal to the accumulated cost up to the segment that the total curtailed energy belongs, plus the cost of the excess energy. Specifically, the total curtailed energy will belong in one of the three different segments, N^B. In the model there exist three segments, $N^B = 3$. However, we keep the variable N^B,so that the model remains generic and customizable.
As stated ,the curtailed energy belongs in the segment *b*. Therefore, the sum of the products $C_b^{DR} \cdot \mu_b$ from 1 to *b*, equals to the total accumulated cost of all the segments up to *b*. The rest of the energy that belongs in the last segment *b*, has a cost that equals to the product of the remaining energy and the respective price per MWh of segment *b*.

4.4 The different models

Based on all of the above in the present research, there are numerous different models created. The research uses the research, continually referenced throughout the text as a modelling base. This model named "poutil", is publicly available through the GAMS Library [38], and is used as a reference.

The original model, "poutil" has as an input the volatile demand seen in Figure 4.4 Energy Demand Volatility. It does equip the provider with the following capabilities, as mentioned above:

- Power production from the natural gas fired powerplant
- Energy received from the SM, through BLCs and 12hour PLCs
- The ability of Demand Response (DR) in quarterly resolution

Solving the case, using the model "poutil", gives a specific cost. This cost refers to the total cost that the energy provider will have to bear, in order to meet the demand. The aim of this research is reminded here, as creating a model aiming to the development of the capabilities of the provider, the integration of more options, as well as the modernization to meet the current situation of the electricity sector.

Therefore, we created two new models, the "Flexible PLCs" and the "Fully Integrated". Starting with the "Flexible PLCs", this model does provide the energy provider with all the abilities of the "poutil" and adds the following:

- Additional energy received from the SM through 4-hour PLCs and 2-hour PLCs

The "Flexible PLCs" model works as a transitional model from "poutil" to the "Fully Integrated". It is useful in order to present the importance of the smaller flexible PLCs proposed.

Finally , the "Fully Integrated" model is presented, which includes all options of the above two models and the additional: Day Ahead Hourly Products.

As explained above, these hourly products of the SM are priced based on HUPX. It is also important to mention again, that in order to preserve the comparability of the new models, "Flexible PLCs" and "Fully Integrated", with the model "poutil", the initial prices of the latter have been altered. Specifically, all prices are based on the hourly prices of HUPX, hence the new prices of all the SM products can be seen in Table 5.

DA Hours	Hourly €	2-hour PLC €	4-hour PLC €	12-hour PLC €	BLC €
1	30.73				37.6
2	26.78				
3	26.07				
4	26.78				
5	29.06				
6	33.85				

<table>
<tr><td>7</td><td>42.78</td><td></td><td></td><td></td><td rowspan="18">37.6</td></tr>
<tr><td>8</td><td>46.42</td><td></td><td></td><td></td></tr>
<tr><td>9</td><td>44.24</td><td rowspan="2">41</td><td rowspan="4">44.3</td><td rowspan="12">40.2</td></tr>
<tr><td>10</td><td>37.78</td></tr>
<tr><td>11</td><td>33.22</td><td rowspan="2">33.1</td></tr>
<tr><td>12</td><td>32.86</td></tr>
<tr><td>13</td><td>30.72</td><td rowspan="2">29.9</td><td rowspan="4">31.6</td></tr>
<tr><td>14</td><td>29.28</td></tr>
<tr><td>15</td><td>31.27</td><td rowspan="2">33.1</td></tr>
<tr><td>16</td><td>34.88</td></tr>
<tr><td>17</td><td>38.84</td><td rowspan="2">42.2</td><td rowspan="4">52.2</td></tr>
<tr><td>18</td><td>45.46</td></tr>
<tr><td>19</td><td>61.29</td><td rowspan="2">62.2</td></tr>
<tr><td>20</td><td>63.03</td></tr>
<tr><td>21</td><td>51.2</td><td></td><td></td><td></td></tr>
<tr><td>22</td><td>40.62</td><td></td><td></td><td></td></tr>
<tr><td>23</td><td>34.95</td><td></td><td></td><td></td></tr>
<tr><td>24</td><td>30.75</td><td></td><td></td><td></td></tr>
</table>

Table 5 SM product prices in the "Fully Integrated" model

Since the ‘Fully Integrated” model integrates all the above capabilities, it is reasonable to present in this last part, before the Results chapter, the final equations for power and cost. The total power of the provider must meet the demand, and is equal to the sum of the power produced in the powerplant, the SM, as well as the curtailed power through DR. Therefore:

$$P_t^{total} = P_t^{PP} + P_t^{SM} + P_t^{DR} \tag{13}$$

Where: P^{total} is the total power provided at time slice *t*

Based on the above equation, we get that the total energy provided is the sum of all the power at each time slice.

$$e^{total} = \frac{1}{4} \cdot \sum_t P_t^{PP} + P_t^{SM} + P_t^{DR} \tag{14}$$

Where: e^{total} is the total daily energy provided in MWh

The e^{total} is the sum of all the power provided during each time slice *t*, divided by four. Dividing by four is necessary in order to provide the energy volume in MWh. This happens because the model has a quarterly resolution, not an hourly.

Moreover, the objective of the model is the minimization of the total cost beared by the provider in order to meet the demand. Therefore, it is calculated through the following equation:

$$c^{total} = C^{PP} + C^{SM} + c_{ER}^{DR} \tag{15}$$

This cost is equal to the cost of providing the respective energye^{total}. As stated before, the model code is based on the code of "poutil", and all the required information and explanations of such modeling are included in [37]. There is no reason to represent and explain the entire model in the present research, but only the additional code and model capabilities that are developed. Therefore, the last modeling development was the integration of two additional constraints to the already existing ones. However, as stated before, the cost equation refers to the total, not to the quarterly curve. The quarterly cost distribution is created after the model solution, using spreadsheet software. The cost and power quarterly distribution were created in the present research and are presented and discussed in Results.

The first constraint refers to the DR program and is actually a transformation of the existing constraint in the original model. All three means, that are in the disposal of the provider to meet the demand, have upper constraints. In the original model, the powerplant can produce up to 300MW, and the power from the SM and DR can both have a maximum value equal to the maximum power demanded. As far as the DR is concerned, such an upper constraint means that the model can have a solution where in some quarters the entire demand would be curtailed. Such an assumption is not realistic and could as well provide unrealistic solutions. In addition, it is clear from the literature review in Demand Response, that a complete engagement of the consumers in DR programs is far from reality. Therefore, even if the scenario of a full curtailment of the entire demand for a specific time period was realistic, and not jeopardizing the systems goal, even then, it would be impossible to achieve. It is so, because that would require the entire demand side (consumers) to be participants in the DR program, translating to a 100% engagement. Therefore, the "Fully Integrated" model constrains the amount that can be curtailed to 150MW, when the maximum quarterly demand is around 500MW, or 33,3% maximum curtailment.

The second constrain refers to the Hourly products. These products belong to the SM, where the power from the SM in the original model has no upper constrains. The same logic was followed to the additional flexible PLCs. However, the hourly products are constrained to a maximum of 100MW. This constrain keeps the model generic, in cases that the Spot Price reaches zero, or very low prices. In such an occasion, the model would choose to meet the entire demand through the hourly product, which is again non realistic. An electricity provider cannot base its entire consumer portfolio in just one product, as it greatly increases the risk. The rest of the constraints can be found in the code of the "Fully Integrated" and the original "poutil".

Poutil: $P_t^{total} = P_t^{PP} + P_t^{SM} + P_t^{DR}, \quad c^{total} = C^{PP} + C^{SM} + c_{ER}^{DR}$	
Power from the powerplant	$P_t^{PP} = 0.1 \cdot (a_s + 2)P_{max}^{PP} \ , \ \forall t \ , \ a_s \in \{2,3,4,5,6,8\}$
Power from the Spot Market	$P_t^{SM} = \alpha + I_t^{12HPL} \cdot \beta$
Power from the Demand Response	P_t^{DR}
Cost of the powerplant	$C^{PP} = c^{pp} \cdot P_t^{PP}$
Cost of the Spot Market	$C^{SM} = C^{BL} \cdot \alpha + C^{12HPL}$
Cost the Demand Response	$c_{ER}^{DR} = \sum_{b=1}^{NB} (C_b^{DR} \cdot \mu_b + P_b^{DR} \cdot e_b^{DR})$
Flexible PLCs: $P_t^{total} = P_t^{PP} + P_t^{SM} + P_t^{DR}, \quad c^{total} = C^{PP} + C^{SM} + c_{ER}^{DR}$	
Power from the powerplant	$P_t^{PP} = 0.1 \cdot (a_s + 2)P_{max}^{PP} \ , \ \forall t \ , \ a_s \in \{2,3,4,5,6,8\}$
Power from the Spot Market	$P_t^{SM} = \alpha + I_t^{12HPL} \cdot \beta + I_{it}^{4HPL} \cdot \gamma_i + I_{jt}^{2HPL} \cdot \gamma_j$
Power from the Demand Response	P_t^{DR}
Cost of the powerplant	$C^{PP} = c^{pp} \cdot P_t^{PP}$
Cost of the Spot Market	$C^{SM} = C^{BL} \cdot \alpha + C^{12HPL} + \sum_t C_i^{4HPL} \cdot \gamma_i + \sum_t C_j^{2HPL} \cdot \gamma_j$
Cost the Demand Response	$c_{ER}^{DR} = \sum_{b=1}^{NB} (C_b^{DR} \cdot \mu_b + P_b^{DR} \cdot e_b^{DR})$
Fully Integrated: $P_t^{total} = P_t^{PP} + P_t^{SM} + P_t^{DR}, \quad c^{total} = C^{PP} + C^{SM} + c_{ER}^{DR}$	
Power from the powerplant	$P_t^{PP} = 0.1 \cdot (a_s + 2)P_{max}^{PP} \ , \ \forall t \ , \ a_s \in \{2,3,4,5,6,8\}$
Power from the Spot Market	$P_t^{SM} = \alpha + I_t^{12HPL} \cdot \beta + I_{it}^{4HPL} \cdot \gamma_i + I_{jt}^{2HPL} \cdot \gamma_j + I_k^H \cdot \gamma_t$
Power from the Demand Response	P_t^{DR}
Cost of the powerplant	$C^{PP} = c^{pp} \cdot P_t^{PP}$
Cost of the Spot Market	$C^{SM} = C^{BL} \cdot \alpha + C^{12HPL} + \sum_t C_i^{4HPL} \cdot \gamma_i + \sum_t C_j^{2HPL} \cdot \gamma_j + \sum_t C_k^H \cdot \gamma_t$
Cost the Demand Response	$c_{ER}^{DR} = \sum_{b=1}^{NB} (C_b^{DR} \cdot \mu_b + P_b^{DR} \cdot e_b^{DR})$
Additional Constrains	$\gamma_i \le 100MW \qquad P_t^{DR} \le 150MW$

Table 6 The three models and their main mathematical formulations

The above Table summarizes the three different models: “poutil”(original), “Flexible PLCs” and ‘Fully Integrated. All the equations have been already mentioned throughout Chapter 4. along with the explanation of each variable and symbol. Table 1 Abbreviations

Chapter 5: Results

In this section the numerical results of all three models are presented and compared. Starting with original model "poutil" we inserted the BLC and 12hour PLC prices and the required constraints mentioned above. Solving the model resulted in a total cost of

$$c_p = 289{,}092.3 \text{ €}$$

Solving the same problem with new models "Flexible PLCs" and "Fully Integrated" resulted in the below costs:

$$c_F = 272{,}092.0 \text{ €}\,,\ c_I = 263{,}871.3 \text{ €}$$

Where: c_p, c_F, c_I are the total costs for meeting the day ahead demand of the model "poutil", "Flexible PLCs" and "Fully Integrated" respectively

From the above it is observed that both of the new models did reduce significantly the daily cost of the energy provider. In fact, the precise cost optimization is presented below after the production results.

In order to properly compare the results of the three models, we start with a detailed analysis of the original model "poutil". The quarterly power contribution of the energy provider is presented in Figure 5.1.

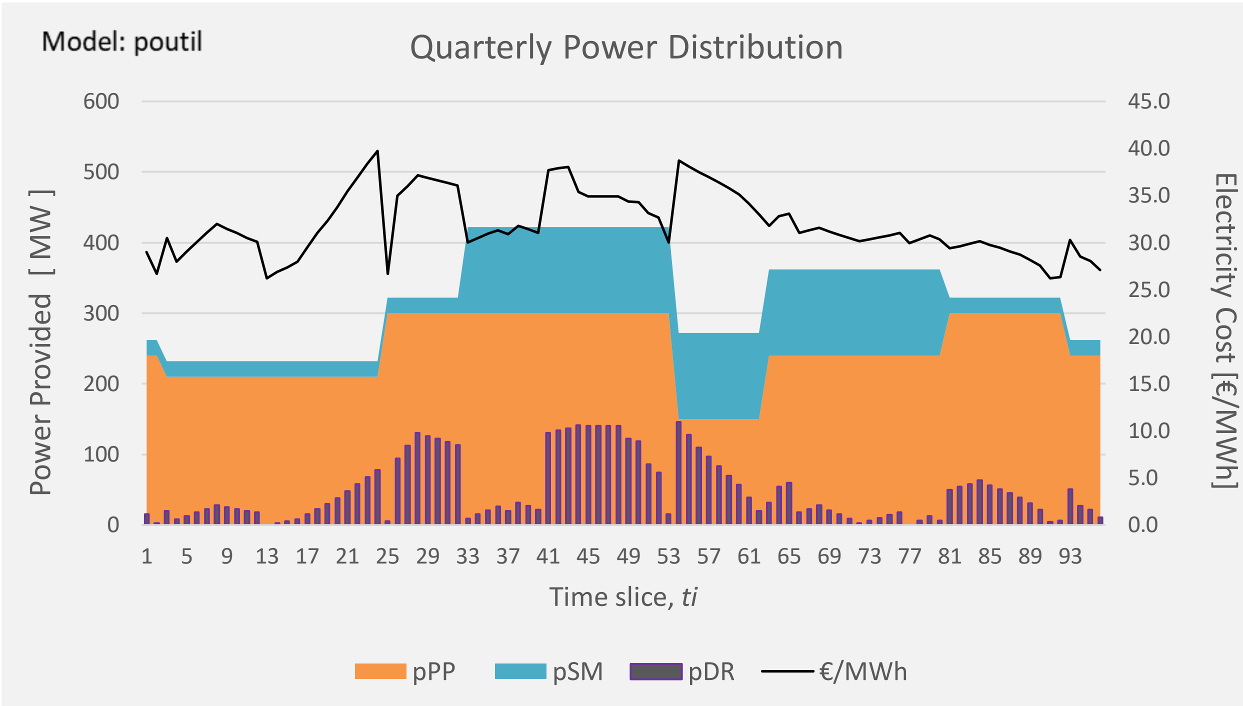

Figure 5.1 Quarterly power distribution, solved with "poutil"

The figure consists of four different elements $P_t^{PP}, P_t^{SM}, P_t^{DR}$ and electricity cost. The first three are not other than the three options, the provider has, in order to meet the demand and the line represents the electricity cost. In detail, the orange area represents the quarterly power production of the providers' natural gas fired powerplant. The cyan area represents the amount of power bought from the SM and the purple columns represent the DR through load curtailment. The figure visualizes optimal solution of "poutil". The quarterly resolution of the figure shows the extent to which the provider utilizes each of the three power options every quarter.

Reminding that, the model has a 100% demand satisfaction as a prerequisite, means that the aggregated quarterly power of all three options equals the quarterly demand. Having said that, it is observed that the demand is greater during peak hours, time slices [33, 80]. Thus, the power load of all options ($P_t^{PP}, P_t^{SM}, P_t^{DR}$) increase respectively. It should be pointed out that an increase in the curtailed power through DR leads to an increased cost, as it is the most expensive among all means of meeting the demand. This is observed at time slices [13, 24], when the increase of DR creates an equivalent increase at the quarterly cost.

After time slice *t25*, the increase of electricity cost is interrupted, as the production of the powerplant and the energy from SM increase too. This happens to control the amount of power coming from the expensive DR program. Generally, most of the expenses occur during the peak hours as the demand is greater that time, forcing the model to utilize more DR, while also balancing the purchased amount of BLCs and 12hour PLCs.

Noticeably, the demand during peak hours is not only higher but also significantly volatile, as it reaches a minimum volume of 262 MW and a maximum load of 563 MW, in less than five hours. At this point, the model has to optimize the amount of power among all options, while the powerplant is already at its maximum capacity of 300MW leaving the rest demand to be met by the SM and the DR. The SM, although cheaper in €/MWh compared to the DR, does have the drawback of smaller resolution, providing only twenty-four hour BLCs and 12-hour PLCs. Thus, the fluctuations of the demand cannot be covered from the SM. The original SM of 'poutil", will reserve each MW for minimum of twelve hours, when it is actually needed for two or less hours. This lack of greater resolution, in the SM products of the "poutil", leaves all these volatile demand to be met by the DR program.

The greater DR utilization the greater the cost, but this is unavoidable when facing volatile demand, as it is the only option with a quarterly resolution. Apart from the economic aspect of this situation, there also exists the realistic. The "poutil" model, that we solve, has an upper constraint regarding the power from DR, equal to 150MW. In the original research [37], the "poutil" model is solved with a DR constraint equal to the maximum energy demand. This means that if it is more economical, the model would solve the problem by meeting even the whole demand through DR. Such a scenario is not realistic, as it destroys the consumer's well fare ,as well as the operation of the system. That is why, as explained in 4.4 in the present research, the "poutil" model is solved with an upper constraint regarding the power from DR.

The upper constraint serves also the purpose of integrating the consumer engagement aspect. As already mentioned, the literature suggests that it is very difficult to achieve complete consumer engagement in DR programs.

The two models created in the present research, do share the same constraints and options with "poutil". The "Flexible PLCs" model presented in 4.4 has the below solution:

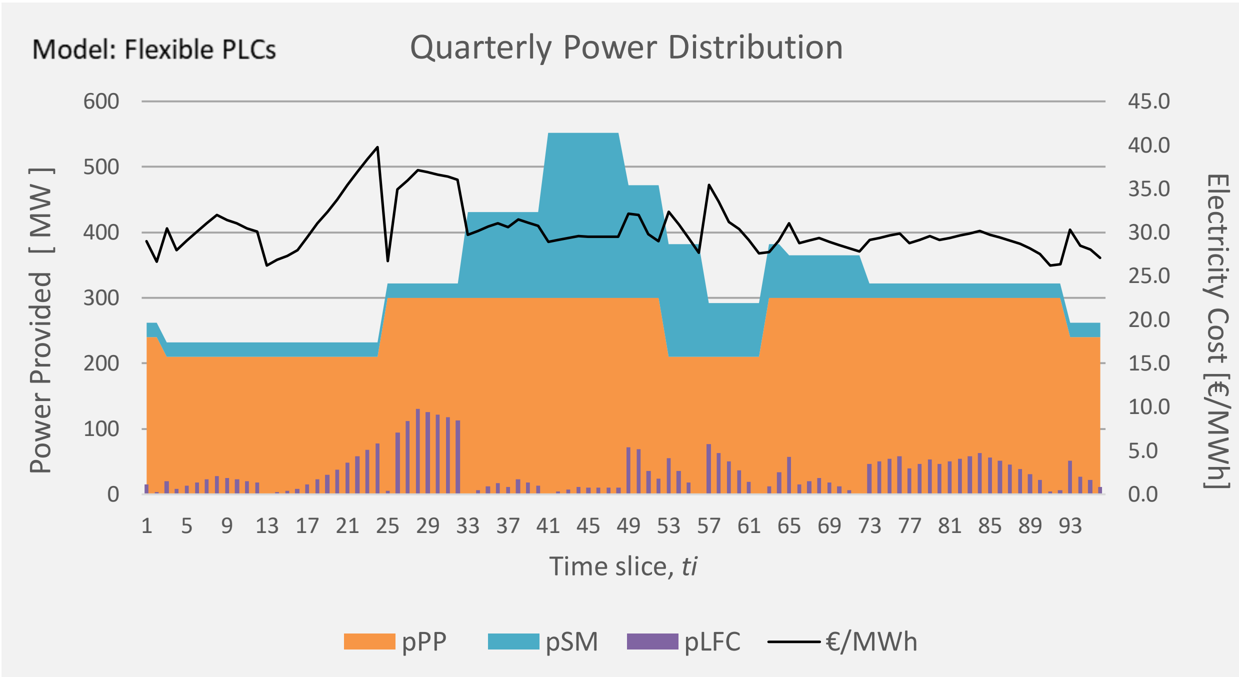

Figure 5.2 Quarterly power distribution, solved with "Flexible PLCs"

From the above figure, three things are of interest. Firstly, the power received from the SM increases, especially during the peak hours and it is more flexible having a higher resolution. This is the result of integrating the 4-hour and 2-hour PLCs into the model. Secondly, concerning the power plant generation, the unit's production reaches the maximum capacity for an extended period compared to that of model "poutil". Finally yet importantly, the power from DR is considerably reduced, especially during the first peak hours, where in model "poutil" was reaching its highest values.

These results underline the importance of the flexible PLCs, which manage to meet most of the demand initially met by DR. Thus, the flexibility of the products plays a pivotal role in optimizing the costs of the provider. However, the PLCs exist only during the peak hours, whereas the hourly products found in every energy market, refer to the whole day.

Moving to the second model developed in the present research, the "Fully Integrated" constitutes the optimum model integrating every option of the previous two models, adding also the hourly products of the SM. In the below figure, the model's quarterly power contribution is presented.

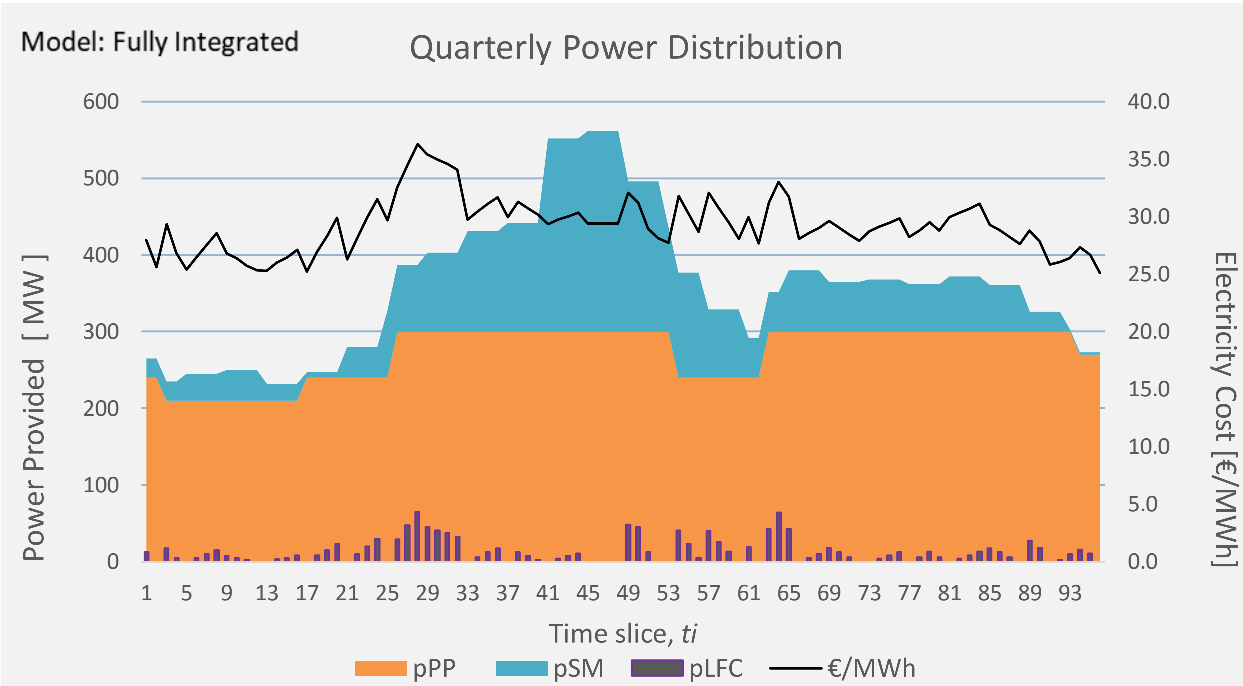

Figure 5.3 Quarterly power distribution, solved with "Fully Integrated"

The integration of hourly spot products is noticeably altering the amount of power received from each of the three options. The powerplant is operating even closer to it's maximum capacity than in the previous models, as well as the power from the SM is increased. Those two factors, along with the increased resolution of the hourly spot product of the SM, constitute an optimization model that utilizes the capabilities of DR, only for meeting the excess demand of quarter resolution. Therefore, the power from DR program is reduced to minimum.

In the above figures, the black curve represents the total quarterly cost in €/ MWh, that is shaped by the respective power from each of the three options. This way we can observe the effect of the power mixture has on the final cost of the provider.

Following the same logic, the below figures present the quarterly distribution of the cost of each of the three options. The orange area, the blue area and the purple columns, this time, represent the respective quarterly cost of the power production of the power plant, the power bought from the SM and the curtailed power through the DR respectively.

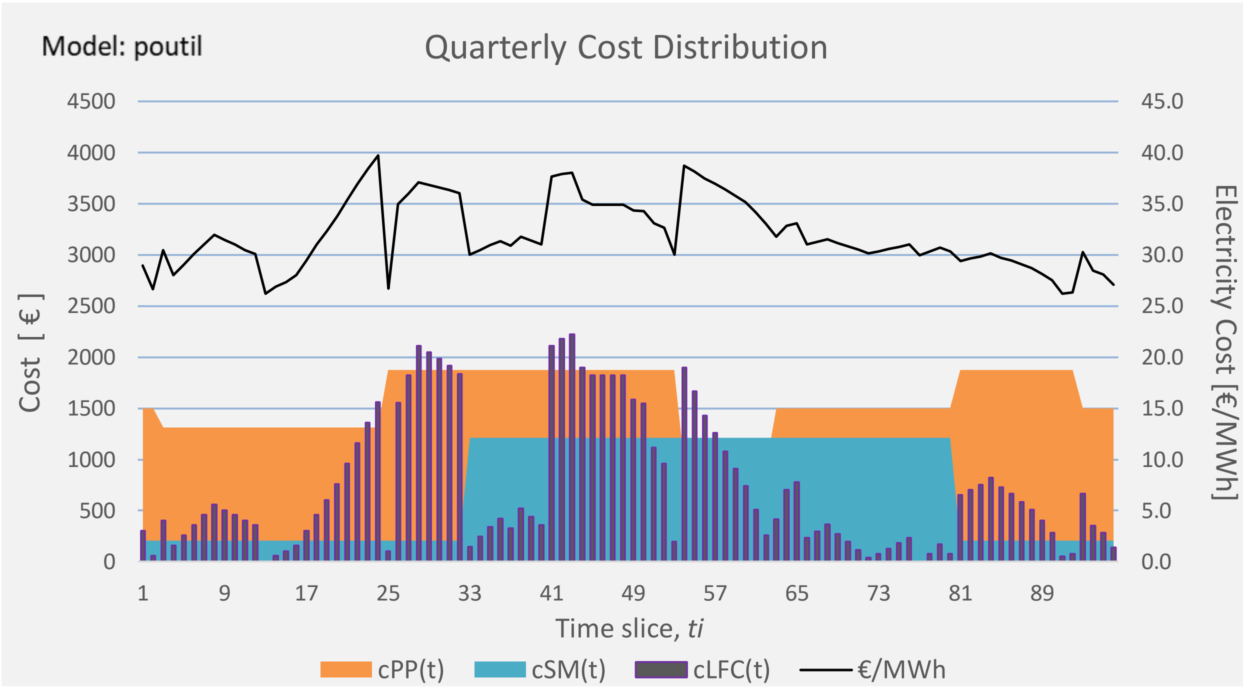

Figure 5.4 Quarterly cost distribution, solved with "poutil"

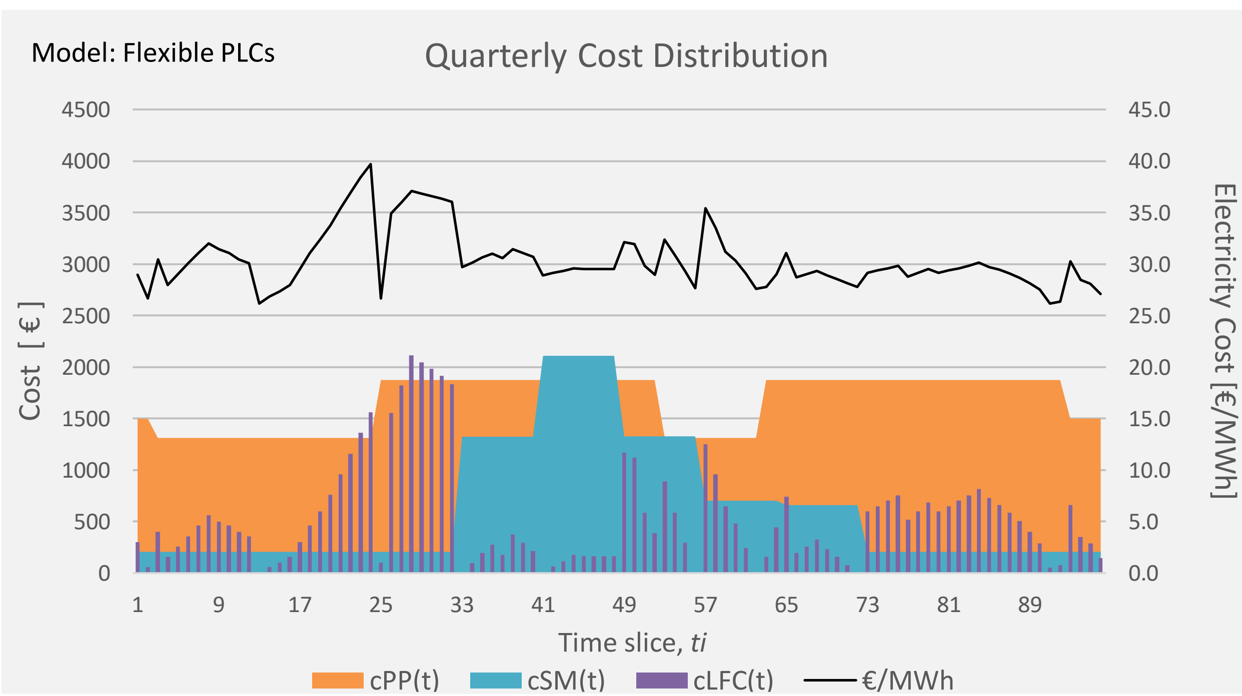

Figure 5.5 Quarterly cost distribution, solved with "Flexible PLCs"

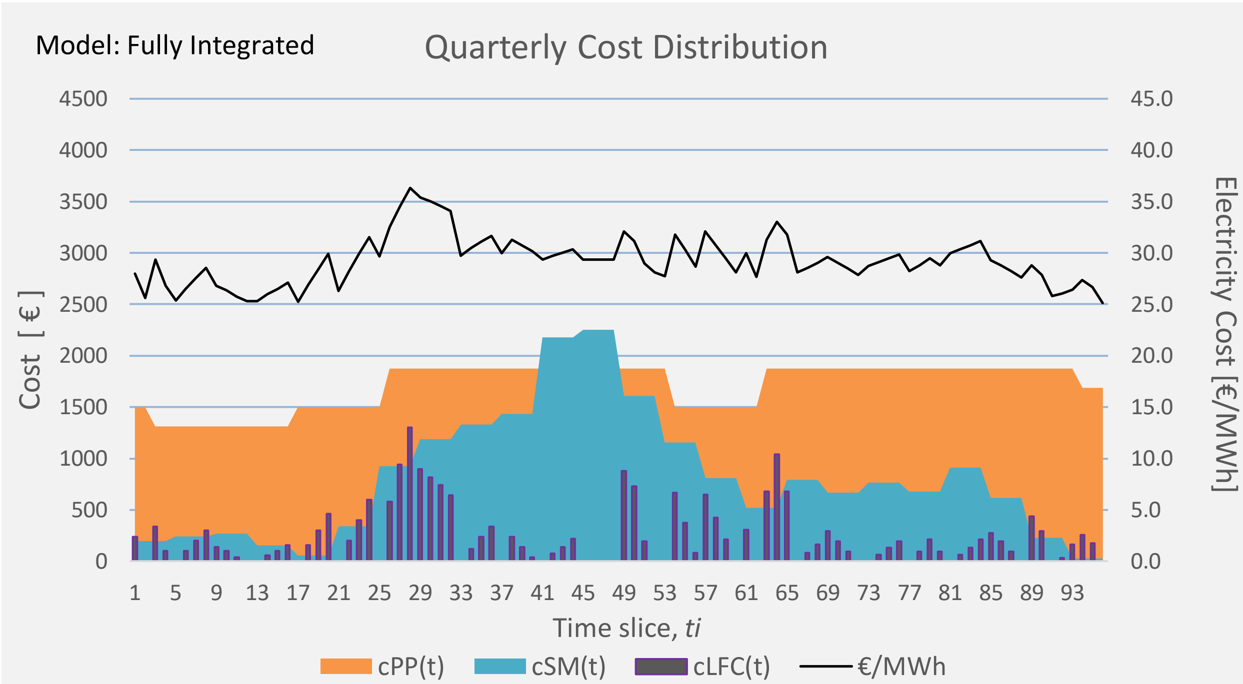

Figure 5.6 Quarterly cost distribution, solved with "Fully Integrated"

The above figures present in detail the solution of each model and its optimization decisions, for each quarter of the day. The optimal solution emerges from the "Fully Integrated" model that maximizes the power production from the powerplant. In addition "prefers" the utilization of power from the SM instead of the more expensive DR program. It does so until the point that the resolution of the SM products can meet the demand, leaving the rest of demand to be met by the DR. It is of importance to remind the constraint regarding the maximum curtailment of 150MW from the DR, that ensures customers well-fare. This constrain prevents also model from curtailing unrealistically big parts of the demand.

The below table compares the two new models to the original, revealing the key factors of reducing the cost of the energy provider.

Model	pPP	pSM	pDR	Total Energy MWh	cPP	cSM	cDR	Total Cost €	Avg. Power cost €/MWh
Fully Integrated	26250	8228	1238	35716	164062.5	77441.34	22367.5	**263,871.3**	**29.2**
2-4hour PLC	25560	6848	3308	35716	159750	60588	51754	**272,092.0**	**30.4**
poutil	24030	6912	4774	35716	150187.5	68092.8	70812	**289,092.3**	**32.0**

Table 7 The values of key variables in the optimal solution of each model

Observing the above three figures of the cost distribution, it is shown that reducing the amount of power covered through DR and satisfying it by the other two options, reduces the overall cost. This can be also properly visualized below, where we present the power mixture of every different model along with its total cost.

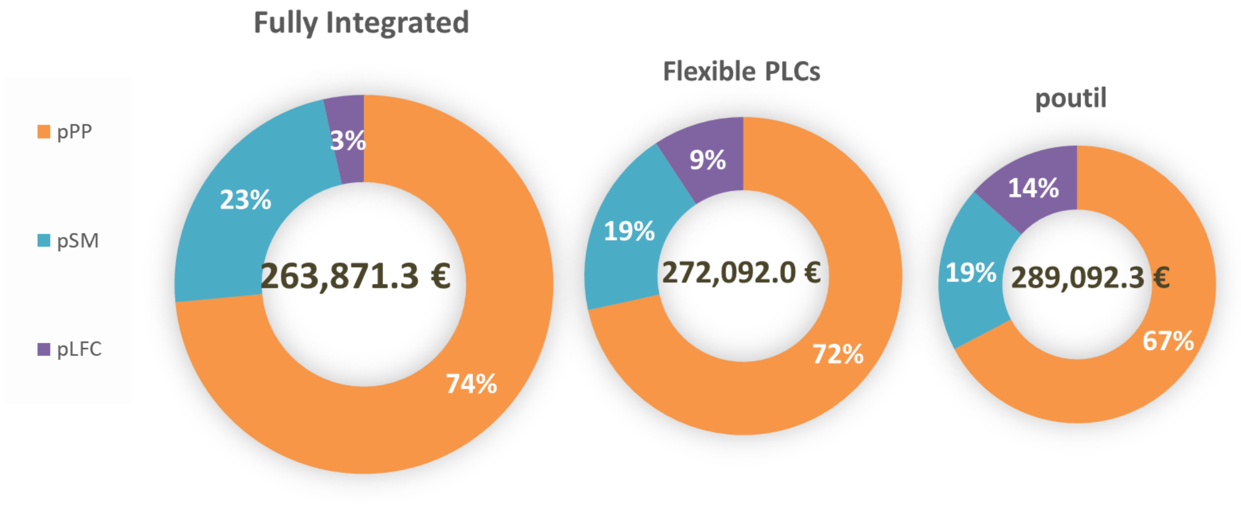

Figure 5.7The different power mixtures of the optimal solution of the three different models

Another significant comparison is that of the final quarterly cost per MWh, that the provider has to cover in order to meet the demand. The visual comparison of this curve, between the three different optimization models, follows in the below figure.

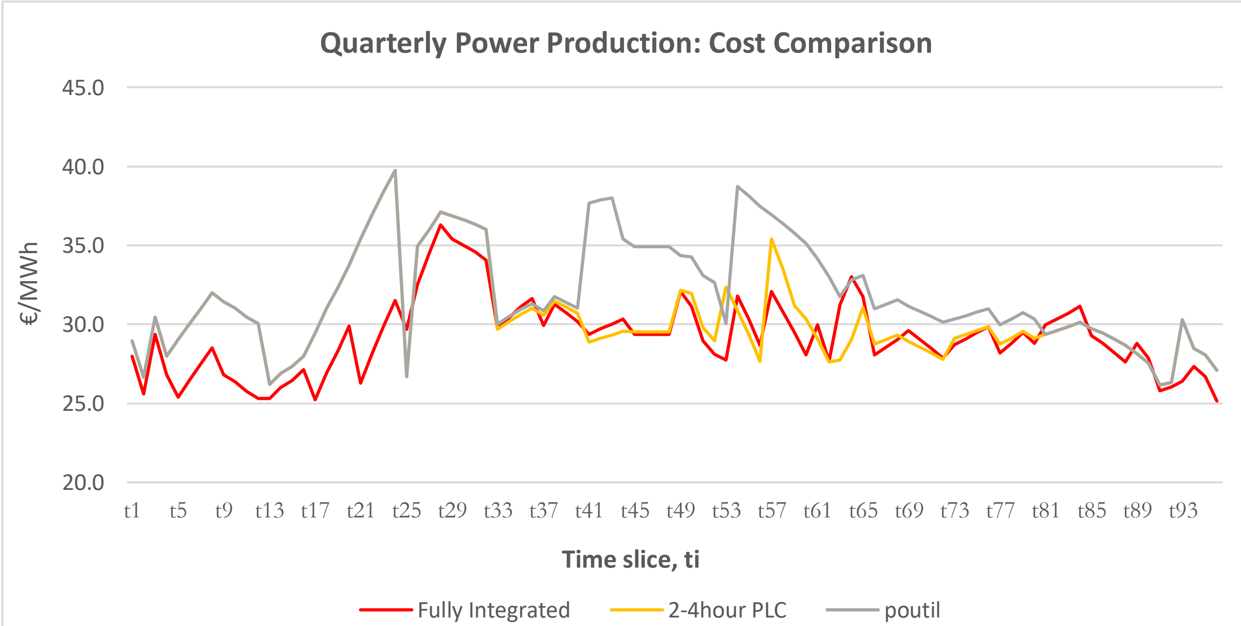

Figure 5.8 Comparing the optimal quarterly cost distributions of the three models

Chapter 6: Conclusions

The present chapter concludes our research and includes all the main points and results, as well as its conclusions. It also sets some guidelines for future research and development of the model.

In the present work, two new models were created, the “Flexible PLCs” and the “Fully Integrated”, with “Fully Integrated” being the final form of the proposed model. A significant reduction in the total cost of the electricity provider was achieved compared to the resolution of the original model. Specifically, the total cost for meeting the daily demand amounts to ***289,092.3 €*** based on the original model “poutil”, and ***263,871.3 €*** based on the “Fully Integrated”. This additional cost reduction equals to ***25,221.0 €*** or ***8,7%*** of the total daily cost.

This significant cost reduction is due to two factors. The first is the creation of new short-term products of the SM, during the volatile demand. The second is the hourly product of the day ahead SM. Both of these additions enabled the supplier to cope with more abrupt changes in demand, by purchasing these products, instead of curtailing the demand. This means that there will be a significant reduction in costs, as the DR is the most expensive option to meet the demand. It is clarified that the significant cost reduction achieved, is not due to the introduction of new lower prices in the market products of the new model, while retaining the old more expensive prices to the original model. Specifically, in the original model “poutil”, which as far as the SM products are concerned, has only BLC and 12-hour PLC, the costs of these two products were redefined based on the hourly prices integrated by the “Fully Integrated” model. The solution of “poutil” was calculated with the new prices and not with the original ones. That way the comparability between “poutil” and “Fully Integrated” is preserved.

Moreover, the new model integrates a significant constraint regarding the DR. This constraint puts an upper limit to the amount of power that can be curtailed quarterly. It is also very important because, as it is mentioned in the literature review, most of the research around DR does not take the consumers’ engagement into account. Therefore, the DR upper constraint takes into account the partial engagement of the consumer portfolio, to nearly one third of the total portfolio. This constraint serves also another purpose, as it restricts the optimal solution of curtailing the entire demand for a specific quarter or time period of the day. Those two changes make the model more realistic, considering not only the cost minimization, but also the consumers welfare and system’s reliability. The reason that DR is the most expensive among the three options that the provider has, is to avoid the extensive curtailment of demand. Finally, it is worth mentioning that this model is generic, therefore it considers any electricity demand or market prices. However, in order to present specific results, only one daily price distribution of demand and one of day ahead hourly prices was used. This means that, although in the present solution some of the PLCs were not utilized, or that the DR did not reach the upper constraint, this could easily occur in another scenario.

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