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ELASTICITY MODELING TO SUPPORT DEMAND RESPONSE PROGRAMS

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Abstract

This work aims to explain why elasticity parameter analysis will assume importance in future scenarios related to a Demand Response context. It is only in the last years indeed that a strong correlation between an updated elasticity value and a balanced electric grid has been defined. A new definition of this parameter is needed since external factors as consumers' habits and possibilities have evolved drastically during the last decade, but also because weather conditions strongly affect green energies productivity, which represent an increasing portion of the overall produced energy; at last, users' location were not usually considered in the calculations. Past papers that dealt with Demand Response (DR) and users' participation used in fact fixed values taken from literature: those values were defined basing on historic consumption data, which didn't differentiate between weekdays and weekends; moreover, only standard classes of users (basing on different voltage level) were considered. For this reason, author's goal is to provide new values based on more recent data, that can be used either from the Distribution Network Operator (DNO) and end-consumers in order to have a more precise value of the amount of power (and then money) exchanged.

A way to extrapolate elasticity from remuneration-power plots is described in this report, and a numeric confirmation of its reliability will be proved using real data as comparison. Moreover, it will be described the economic impact of this tool if used to make estimations of power/money traded.

A case of a consumer who is asked to switch electric contract will be also studied, taking into consideration economic benefits (both from his point of view and DNO's) and technical constraints. Tariffs and consumption data of the Portuguese context will be used: it shouldn't represent a constraint since the model itself can be applied to any user who can choose a double tariff contract and a triple one over a mono-tariff.

Keywords

Demand Response (DR), Distributed Generation (DG), Elasticity evaluation, Electric markets, Energy contracts

Riassunto esteso

Questo lavoro è finalizzato allo studio dell'elasticità delle utenze elettriche inserite in un contesto in cui viene applicato il Demand Response (DR). Tale programma ha come obiettivo quello di mantenere la rete elettrica stabile, evitando congestioni e relativi picchi dei prezzi dell'energia. Poiché il DR richiede interazioni in tempo reale tra gli operatori di rete e le utenze finali, esso può essere applicato solamente in presenza di *smart grids*, dove le utenze sono provviste di contatori smart in grado di gestire flussi bidirezionali di potenza e di ricevere costantemente aggiornamenti sullo stato della rete. Il continuo aumento delle fonti rinnovabili nel panorama energetico ha incrementato da un lato la generazione di energia *carbon-free* ma dall'altro le criticità legate a queste fonti alternative: fra queste, la loro natura aleatoria che ne impedisce una precisa programmazione e pianificazione a lungo termine. Per questo motivo risulta sempre più determinante il dialogo fra rete e utenze: così facendo infatti, si è in grado di sfruttare al meglio i momenti di alta produzione e di diminuire la richiesta di energia qualora essa non fosse disponibile in grandi quantità. Ciò implica che la curva di domanda dell'energia segua quella di produzione, dettata sempre di più, come menzionato sopra, dalle fonti rinnovabili. Al fine di adattare la curva del carico a quella della produzione, occorre incentivare i consumatori a variare le loro abitudini per quanto concerne l'utilizzo dell'energia elettrica: in questo elaborato si è adottata, come incentivo, una remunerazione di tipo economico. Nel passato già si è usato questo tipo di incentivo per spostare i consumi verso ore con maggiore produzione, adottando le cosiddette "fasce orarie": in questo studio si è voluto partire da questa base per creare un modello dove, oltre alle fasce orarie, entrano in gioco gli intervalli con alta produzione nei quali l'energia viene a costare meno (data la poca domanda e la grande offerta). Si è quindi supposto che a un utente venga proposto di passare da un contratto per la fornitura di energia elettrica di tipo mono-orario a uno di tipo bi/tri-orario in modo da avere più tariffe nell'arco della giornata in cui spostare i consumi di potenza; con un contratto di tipo bi-orario o tri-orario infatti, oltre ad essere l'utente finale a beneficiarne (in quanto si hanno più scaglioni di prezzo rispetto a un mono-orario che ne è privo), anche il gestore stesso della rete può trarne beneficio in quanto può localizzare nell'arco delle 24 ore il momento in cui conviene indirizzare i consumi degli utenti, garantendo così stabilità alla rete. La disponibilità di un utente ad anticipare o posticipare i suoi consumi in base a una ragionevole remunerazione definisce la sua *elasticità*, fattore che in ambito elettrico è stato definito a inizio anni '80 ma che solo ora sta assumendo grande importanza. L'elasticità infatti garantisce una stima della potenza che può essere ottenuta da una specifica tipologia di utenza (una piccola impresa, un'utenza domestica, un edificio scolastico…) qualora fosse necessario ridistribuire l'energia in rete verso carichi maggiori per brevi intervalli di tempo (senza ricorrere a sistemi di stoccaggio o acquisto di energia dall'estero). Inizialmente tale parametro non veniva sfruttato dagli operatori di rete in quanto non erano presenti utenze attive (cioè in grado di produrre energia a livello locale per autosostenersi o per venderla alla rete). L'avvento delle rinnovabili (e quindi delle utenze attive) e l'aumento dei consumi energetici hanno fatto sorgere la necessità di bilanciare i flussi di potenza in rete: uno dei mezzi disponibili più adatti e immediati da utilizzare è l'elasticità stessa. Poiché tale strumento non è mai stato sfruttato, i valori di elasticità definiti per le diverse classi di utenze sono relativi ai consumi di fine '900 e pertanto non sono adatti al contesto energetico attuale. In questo elaborato si è voluto pertanto partire dalla definizione di elasticità per poterla adattare al contesto attuale, aggiornando i valori per le diverse tipologie di utenza. Dopo aver presentato i vantaggi relativi a un valore sempre aggiornato dell'elasticità degli utenti, si è proposto sia un metodo in grado di ottenerla da dati più recenti, sia un modello in grado di stimarla. Il primo step consente di definire, seppur a posteriori, l'esatto valore che l'elasticità ha assunto nell'arco delle 24 ore precedenti (poiché sono noti i consumi e le tariffe in cui sono stati spostati): ciò permette di avere una stima piuttosto precisa di questo parametro adattabile a utenze simili dando così beneficio all'operatore di rete, ora in grado di stimare con più precisione i valori di potenza che circoleranno in rete. Il secondo step invece ha come risultato un modello in grado di prevedere con più precisione l'andamento dell'elasticità nell'arco delle 24 ore successive: l'evoluzione rispetto al punto precedente è data dal fatto che ora si sfruttano i dati storici solo per definire inizialmente i valori di elasticità; tali valori infatti vengono interpolati e la loro interpolazione consente di avere una legge adattabile a un'altra giornata/utenza senza dover ricorrere nuovamente ai dati storici. Poiché tale operazione richiede costi computazionali, si è fatto un confronto tra il primo e il secondo step calcolando gli errori introdotti i quali, in questo contesto, rappresentano un eccesso/difetto di potenza consumata e di conseguenza diversi valori di remunerazione, a scapito sia delle utenze finali che dei TSO (Transmission System Operator). Si è dimostrato che l'utilizzo del secondo metodo è nettamente migliore in quanto, oltre ai vantaggi già elencati, non comporta grandi costi computazionali e non introduce errori apprezzabili. Un altro motivo che ha spinto a dare una nuova definizione dell'elasticità è legato alla sua estrema variabilità dipendente dal giorno della settimana (feriale o festivo), dalla posizione dell'utenza (se è localizzata presso un nodo debole o forte del sistema elettrico) e dalle condizioni metereologiche che determinano la produttività degli impianti *green*: tutti questi fattori in passato sono sempre stati trascurati quando si stimavano i valori di elasticità delle utenze.

Lo studio è stato effettuato simulando degli scenari basati sui dati della rete portoghese: ciò non preclude la sua adattabilità ad altri sistemi elettrici, in quanto i modelli creati lavorano con qualsiasi dato di input e gli andamenti delle curve di carico sono simili in ogni Paese.

Il lavoro è diviso in sei capitoli: i primi due capitoli servono a introdurre il lavoro definendo il contesto in cui è inserito e le motivazioni che hanno portato alla sua stesura; il terzo capitolo presenta il concetto di elasticità e come si è arrivati alla necessità di valori aggiornati; il quarto capitolo indica la struttura del lavoro di simulazione presentata nel capitolo successivo, in modo da avere una guida da seguire nel caso si volessero ripetere e migliorare le simulazioni svolte; il quinto capitolo è la simulazione, eseguita basandosi su dati reali e ottenuta ipotizzando scenari in cui poter applicare il DR. Infine, il sesto capitolo presenta le conclusioni di questo elaborato.

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Acronyms

DR – Demand Response

DG – Distributed Generation

DNO – Distribution Network Operator

RES – Renewable Energy Sources

DSO – Distribution System Operator

PX – Power Exchange (market)

TSO – Transmission System Operator

RTP – Real Time Pricing

IDR – Incentive Based Demand Response

VPP – Virtual Power Player

1. INTRODUCTION

Elasticity of electric consumers has been assuming growing importance in the last times. Being defined as the will of a user to modify its power consumes (after a remuneration), it goes without saying that it can have strong impacts on future energy scenarios. Theoretically speaking, power production would be supposed to match constantly power consumption, giving benefits both to grid balance and price spikes. Elasticity is one parameter of the so-called Demand Response, a program that is supposed to manage in an optimal way power fluxes in the electric networks by rewarding end-users and, hypothetically, promoting green energy. In fact, climate change together with an increasing electricity demand by 80% within 2040 [1] makes DR with all its aspects a fundamental matter for the future of energy. Since DR doesn't present any structural requirement nor constraint, it can be applied to every type of electric system.

It is author's desire that this document can be used and improved by other students and researchers who care about technological development, economic optimization and also about environmental issues.

1.1 CONTEXT

In the last decades electric systems have been involved into lot of changes required by the evolution of both consumers' and producers' technologies and economic constraints. Engineering fields as informatic, telecommunications, control systems and computations (e.g. Internet of Things and Artificial Intelligence) have made available tools that can strongly benefit this sector [2], [3], i.e. the smart grids context. Moreover, most of electric markets have switched from monopolies to liberalized markets with the presence of more competitors, making consumers more active and influential also in the energy-buying process [4]. More powers to consumers, reliable and fast-communicating devices installed on grids and the increasing environmental issues, are all together reasons that make the actual world ready to host smart-grid technology.

1.2 OBJECTIVES

This work aims to study consumers' impact on power production in a future scenario, in particular with a well-defined elasticity parameter for every type of user.

In order to accomplish that goal, the following points have been examined:

- Study of methods available in literature to establish elasticity values;
- Study and implementation of different scenarios to evaluate effects of computed elasticities on remunerations;
- Development of a method able to follow real-time demand in order to define real-time elasticity;
- Adapt correlation methods to different types of consumers and evaluation of the economic impacts;
- Simulation of a contract change for a generic user to study how to promote double/triple tariffs contracts.

The reason that led the author to that choice is that currently elasticity parameters are the ones used more than 20 years ago: since users' habits, needs and possibilities are changed (e.g. with the incrementing penetration of electric vehicles), these parameters need to be updated. Not only: a well-defined value, constantly updated, would allow to minimize exceeding production and price spikes (in some cases easily from one-half to two-thirds [5]) by keeping the grid constantly balanced.

1.3 CALENDARIZATION

This work required about 7 months, from October 2018 to April 2019. While the first two months were used to gather information about the state of art of elasticity in the Demand Response context, the rest of the time was dedicated to develop scenarios and simulations.

1.4 WORK ORGANIZATION

After this introduction, four chapters are present and a final conclusion concludes this report. In the second chapter, an overview of electric systems and markets was done because Demand Response (DR) has a strong influence on them. In fact end-users' consumptions habits have been acquiring importance since they determine the amount of power to be generated. As already mentioned, new habits and possibilities of electric consumers represent both means and challenges to the DNOs all over the world to manage power fluxes into the grid, keeping it balanced.

Since power blocks are strictly connected to money exchanges, some markets structures are described briefly. They are supposed to complete the panorama of the DR/smart grids context.

In the third chapter, DR has been discussed as a mean adopted in some countries and as a subject of study for researchers all over the world. In particular, in the same research unit this report was written[1], researchers work on other aspects of DR such as clustering and aggregations: that's why these arguments are briefly described here. Gathering information and data will represent a hard challenge for next generations, since high-tech devices are going to be always more essential to people's lives and, in order to perform at best, they need to constantly give/receive data about everything. Models and algorithms that work in this field may also work in others, like the "big-data" and "artificial intelligence" one. The high feasibility of this argument is the reason why it has been selected and put into this report.

In the following chapters data and results of author's work are showed and discussed. The work can be divided in sections, all of them correlated by the same purpose: an optimization of the power-money system. Methods are explained step by step and the all equations used are fully described. Finally, a simulation of a possible scenario has been analyzed bringing to important conclusions and considerations, both from an engineering prospective and an economic one.

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[1] GECAD - Research Group on Intelligent Engineering and Computing for Advanced Innovation and Development.

2 Related Literature

In this chapter it is presented what has been found on literature about Demand Response and elasticity. If DR is a topic faced by lot of researchers[2] and electric companies, giving lot of papers and books as a result, one the other hand elasticity (in DR context) has been discussed intensively only in the last years, therefore less documentation is available. In addition to these topics, an overview of how an electric system is constituted and how electricity market is divided is here presented, since it's necessary to understand the context in which this work is placed.

2.1 DEMAND RESPONSE

As said in [6], DR programs are defined as alterations of load profiles according to incentives provided by network operator due to technical reasons or economic purposes. In a more detailed way, it can be described as a "tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized" [7]. Despite DR is not a recent phenomenon (it has been decades that congestions have occurred during demand-peaks periods [6]), only in the last decade technological development has allowed to manage power fluxes in a smart way: in the past consumers were informed about high demand periods only by

[2] According to [46], publications increased exponentially, from some issues per year in the 1990's to some thousands per year after 2010.

the different scheduled tariffs applied over the 24h. Nowadays instead it is possible to use users' flexibility: this would be the way to employ both buildings and energetic resources more efficiently.

According to data of the" Respond" project [8], "DR market is expected to grow to $9.7 billion by 2023" with a capacity (GW) that will grow exponentially. Fig.2.1 shows how installed capacity is expected to grow in the macro-areas of the world[3]. Nowadays USA has the "most developed DR market in the world" where commercial and industrial customers cover most part of it in terms of "incentives, flexibility and savings" despite they participate only of 10% of it.

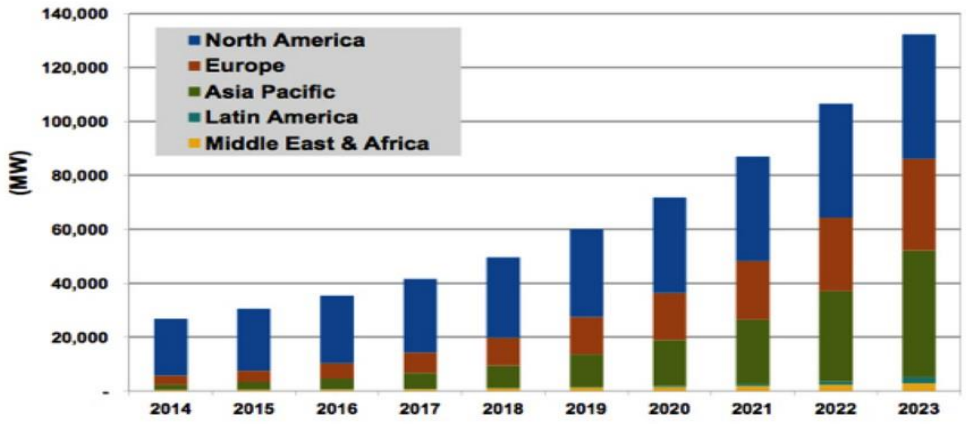

Figure 2-1: DR capacity trend for industrial and commercial customers [8]

Focusing on Europe, in 2014 the total DR resource capacity stood at 2 [GW] while a study conducted by Sia Partners in 2015 stated that the total DR potential in Europe amounts to 52.35 [GW], 42% of which coming from residential applications, 31% from industry and 27% from tertiary sector.
Nowadays the most promising European countries for DR program technologies are Switzerland, France, Belgium, Finland, Great Britain and Ireland.

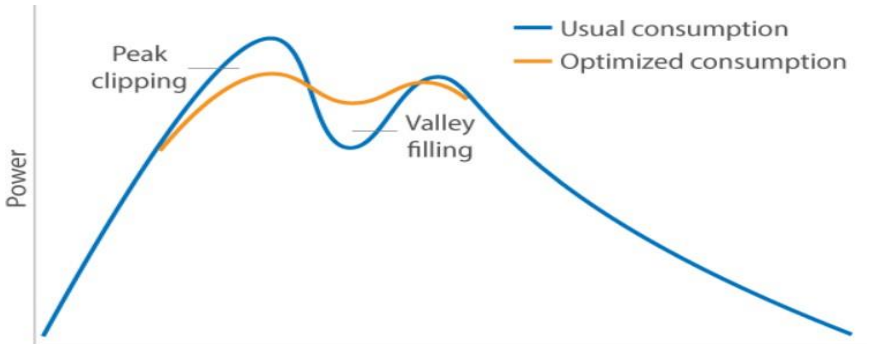

Figure 2-2: Power trend during the day and its optimization [3]

[3] Data taken from the *Federal Energy Regulatory Commission (FERC), National Assessment and Action Plan on Demand Response. 2009. A National Assessment of Demand Response Potential.*

The most evident advantages of DR, as it is explained in the next paragraphs, are a decreasing pollution level, a more stable electric network with "peak shaving/valley filling" (Fig.2.2[4]) and less price spikes occurrences. All these benefits are connected to the simple operation of moving consumptions into periods where "green" power is available, that is what DR aims to.

As a proof of environmental benefits, it worth to be cited the "Earth Hour environmental campaign"[5]. S. Gyamfi and S. Krumdieck reported in [9] a notable initiative that took place in New Zealand. On March 29, 2008, residents of Christchurch responded to a well-advertised and council supported call to reduce electricity demand for one hour as a symbolic action. The campaign focused on turning off lights for one hour to "make a difference" and to "show concern for climate change". The official measure of demand response between 7:00 pm and 8:00 pm was a 13% reduction. Demand Response (DR) then appears to be a useful tool both for end-consumers and network operators, since grids are always balanced minimizing all costs and taking care of environmental issues.

Among European countries, Italy too is researching for technologies able to optimize DR once they are inserted into a smart grid context. For example Enel[6], one of the most important Italian Network Operator (DNO), is investing in the "Research&Development" sector to insert DR into electric market and electric system in the best way possible. Enel presents DR as a sequence of steps, that are quite the same as any other electric market:

1. Network operator detect a congestion/fault in the electric system and informs the aggregator;
2. The aggregator receives the balancing message and manages power with optimization algorithms;
3. After the notification, consumers change his consumption/production;
4. Network operator is informed about the succeeded balancing operation;
5. Once the operation is ended, remuneration to clients occurs basing on contracted terms.

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[4] Image taken from the USA *Northwest Power and Conservation Council* website https://www.nwcouncil.org/energy/energy-topics/demand-response

[5] https://www.earthhour.org/

[6] https://www.enelx.com/it/it

Benefits of Demand Response

DR can be seen as a tool that allows the DNO to better match real time demand and supply curves: this guarantees more efficiency to the system since fluctuations are kept small. Thanks to the correlation between active power and frequency, small fluctuations of (active) power bring little oscillations of frequency as well, representing a big benefit of DR.

In the past a constant balance of the electric network was seen as a hard goal to get since problems as:

- generation units forced outages;
- transmission/distribution line outages;
- sudden load changes;

were able to change demand and production rapidly and unexpectedly [10]. In future scenarios instead, an optimal management of load and supply curves can be achieved thanks to DR, allowing to deal with problems like the ones mentioned above in the most efficient way, from a technical and an economic point of view. Participants indeed have the opportunity to help in reducing risk of outages [10] and operator will have more options and resources to maintain system reliability [11].

Demand Response seems to be an important solution to the increasing demand of power: it allows indeed to manage real time power avoiding increasing production or buying energy from other countries. Therefore advantages could be reached also in terms of environment pollution [12] and energy prices.

Focusing on this last benefit, in [10] three actions that can be adopted from a customer are listed:

- **Reduce electricity usage during tariff-peak periods:** this option involves a temporary loss of comfort (e.g. changing heathers/AC settings);

- **Move peak demand operations to off-peak periods:** customers will bear no loss and will incur no cost;

- **On-site generation usage:** if a consumer owns a source of power, his consumption trend may not follow high tariff schedule and experience no variations; however, for the DSO, demand will appear to be smaller.

Programs such as DR can bring benefits to every participant of the electric market: producers would always generate power (in fact lacks of demand are supposed to be constantly filled), end-consumers would not face anymore price-spikes and price volatility would be reduced in the spot market [10].

Another important benefit is that DR ”reduces the ability of main market players to exercise power in the market” [5]: during California electricity crisis of 2000-2001, a reduction of only 5% of demand could have resulted in a 50% price reduction [13]. Nowadays a large amount of carbon plants works as reserves in order to provide security to the power supply.

It happens especially in those power systems where a high penetration of non-predictable renewable generation is present [6]. Demand response represents an alternative solution to flexible generation resources, inter- connections between countries and electricity storage. An advantage of DR compared to these solutions is the lack of technological impediments since the required communications and monitoring technologies have been already developed [14].

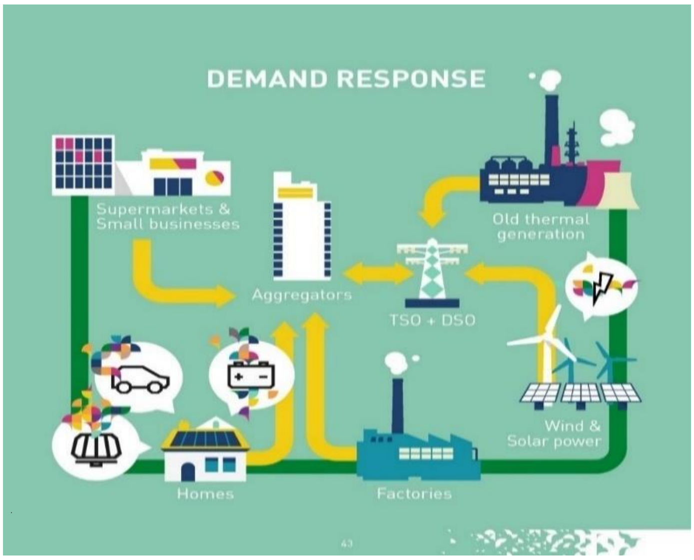

Figure 2-3 : Representation of power fluxes in a DR context [15]

DR brings a lot of benefits that can be enjoyed by every player of a smart grid based electric system (Fig.2.3). An example is given by a system with high wind generation where a big amount of reserve is required to keep the overall system balanced: instead of installing big capacity reserves, DR can curtail or shift loads both in geographical and time terms. In this way, power plants wouldn’t work at partial load (which is inefficient in terms of fuel consumption and it ruins the machines). It has also been demonstrated that by adjusting instantaneously lot of small loads a more effective ramping rate can be achieved compared to single larger generating plants [6]. Moreover, as acquiring and maintaining generating capacity represents a significant component of the total costs of a power system [16], DR represents a solution to reduce overall costs. Finally, it assumes importance the energetic independence that countries would have towards neighbouring states: an optimal utilization of the energy inside a region/country can avoid the need of buying it from other countries.

Application and programs

DR can be implemented as a total curtailment of the load or a partial reduction of it. This latter case introduces the definition of elasticity, a parameter that is presented and discussed in chapter 3. Price Elasticity of demand is the measure of the responsiveness of the demand to its price [17]. In other words, it represents how much a consumer is willing to change his power absorption considering a remuneration variation. Its expression is given by the (2.1):

$$e = \frac{\Delta Q/Q}{\Delta P/P} \tag{2.1}$$

where Q represents the initial demanded quantity, ΔQ its variation, P the initial price and ΔP its variation. Each consumer type may present its own elasticity value; moreover, it can change according to the day of the week or other factors as weather conditions, therefore a complete analysis is required.

Costs of Demand Response

New measurement tools and devices are needed in order to perform DR program in the best way. Their prices and their installation costs represent the first issue that is faced when operators/consumers decide to participate this program. For example, instruments' requirements such as "smart thermostats, peak loads controls, energy management systems, on-site generation units" [10][18] are mandatory, but expensive. Besides these advanced metering systems, other types of expenses must be considered:

- **less comfort:** users who join DR have to "sacrifice" their power absorption routine in order to be remunerated. This may result in a small change, as a different setting of a thermostat for a domestic user, or in a big one, as a complete rescheduling of an industrial process;

- **fuel for backup generating units:** whenever a costumer decides to always have a second power source, costs of fuel and maintenance have to be taken into account;

- **upgrading billing system:** power meters have to be upgraded in order read bi-directional power fluxes and receive constantly information about electricity price;

- **educational costs:** investments are necessary to inform people about DR programs, how they work and why everyone should join them. In fact it may look only as a loss of comfort for the end-user and not as an opportunity to have discounts on bills and use energy in a green way.

Price-based DR and Incentive-based DR

Methods of engaging customers in DR can be divided in two wide groups, namely "*price-based* DR" and "*incentive-based* DR" [7].

Price-based DR is related to the changes in energy consumption by costumers in response to the variations in their purchase prices, since tariffs fluctuate following the real time cost of electricity [10]. The purpose of this kind of DR is to flatten demand curve by offering a high price peak periods and lower prices during off-peak periods. This group includes the following programs, that for now are all voluntary:

- time of use (TOU);
- critical-peak pricing (CPP);
- real time pricing (RTP);

Time of use includes different prices for usage during different spans of time, usually defined in a period of 24h. This rate follows the average cost of generating and distributing power during the day. It is supposed to incentivize "night-valley filling" by shifting loads from day to night hours. The simplest TOU rate has 2-time blocks: peak and off-peak.

Critical-peak pricing is slightly different from the TOU program because peak prices are defined according to specific conditions of the grid. It's supposed to be for larger commercial and industrial consumers [6]. CPP prices are supposed to be used during grid congestions or high wholesale electricity prices for a limited number of days/hours per year [19].

Real time pricing defines prices of electricity for short periods of time, like 1 hour, reflecting the price changes in the electricity market. Customers are charged hourly with these fluctuating prices.

Incentive-based DR includes programs that give the customers fixed or time varying incentives in addition to their electricity rates according to their consumption reduction. Some of these programs penalize customers that fail the contractual response when events are declared. The incentive-based group includes the following 6 programs [20]:

- *Direct Load Control*: it considers a remote shut down or cycle of a customer's electrical equipment (e.g. AC or water heaters) by the program operator. It's addressed especially to residential or small commercial customers and usually is executed on a short notice.

- *Interruptible/Curtailable Service*: it is based on curtailments option integrated into retail tariffs that provide a rate discount or bill credit by agreeing to reduce load in critic moments for the grid. Generally this program is offered to larger industrial customers.

- In *Demand Bidding/Buyback* programs costumers offer curtailment capacity bids.

- *Emergency DR* can be expressed as a mix of Direct load control program and Curtailable Service. It's used when reserve becomes insufficient.

- In *Capacity Market* programs customers offer load curtailment as system capacity to replace conventional generation or delivery resources.

- *Ancillary Services Market* is similar to Demand Bidding/Buyback program, but now offer is just made for ancillary services market.

According to [10], the first two programs (DLC and I/C service) belong to the so-called "classical IB program"(IBP) since participating customers are given remuneration as bill credit or discount rate. The last 4 programs instead belong to the "marked-based IB program" since customers are rewarded with money for their performance according to their load reduction during critical conditions. Participants in classical IBP are entitled to receive incentive payments for their participation, while market-based IBP customers will receive payments according to their performance.

Amongst price-based DR, in particular RTP, and incentive-based DR, the most promising one is RTP: a long-run study of RTP efficiency conducted in [21] demonstrated that efficiency gains from RTP are significant even where elasticity of demand is very low. Moreover, TOU tariff provides very small efficiency gains compared to RTP.

2.2 DISTRIBUTED GENERATION

With "distributed generation" (DG) it is denoted the placement of medium-small electrical power generation units close to the end user or connected at a medium/low voltage level to an aggregator (whose role is presented in the next paragraph) that interfaces the grid. Most of the times DG is related to renewable energy sources: wind, water, sun, biomass (Fig.2.4).

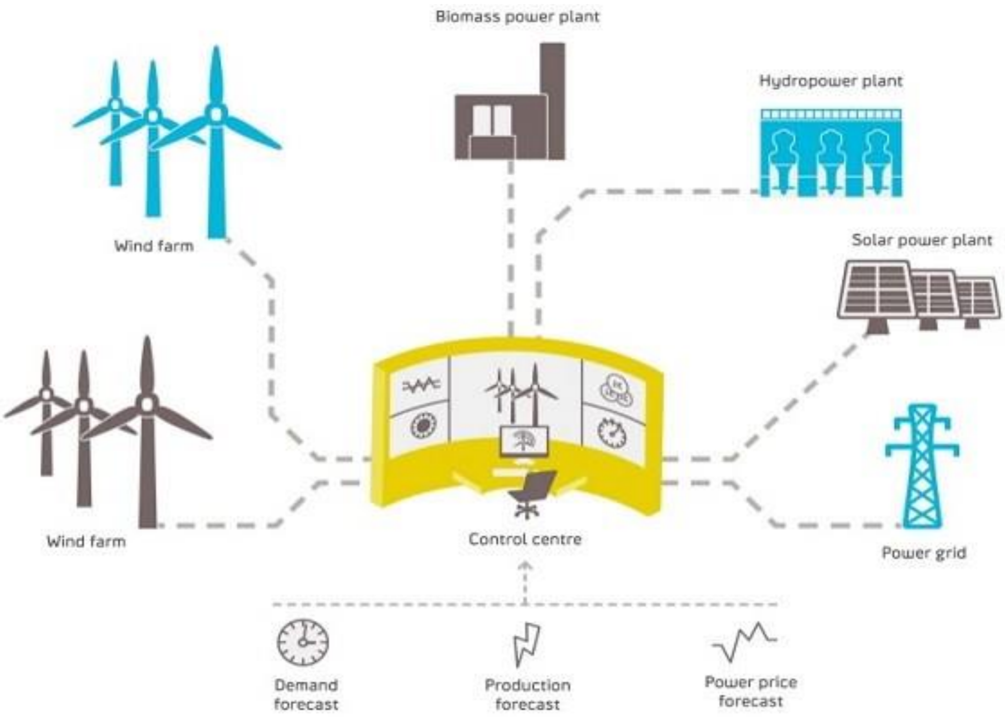

Figure 2-4: Representation of Distributed Generation sources in the grid [22]

Distributed Generation growth is related to the increasing utilization of renewable energies by small users thanks to their affordable prices of installation. Moreover, DG presents many benefits, including:

- Reducing of electricity bills (remuneration is proportional to energy contribution [8]);
- Increasing the reliability of electric power;
- Improving the payback of required generation systems;
- Making power marketable to sell to utilities;
- Generating green energy;

- Congestions relief;
- Loss reduction;
- Peak shaving;
- Possibility to use co-generation on existing industrial plants;
- Taking benefits from urban solid waste material;
- Opportunity to generate power close to loads, having benefits in terms of power factor and voltage stability without installing new lines [9];

As described by Dilek[7] and Broadwater[8] in the book [23], an important feature of DG is that can be operated to control voltages [24] and power flows within the distribution system. They also state that more improvements in distribution system reliability and overall power system efficiency can be realized. In particular, for load growth with short-lived peaks that occur during extreme weather conditions, future DGs may provide lower-cost solutions than other approaches to system capacity upgrades. DG indeed provides means for increasing capacity of existing distribution facilities being an alternative to new substation addition and replacing existing equipment with larger ones. It has been demonstrated also that line losses can be reduced [25].

A DG installed at the distribution level releases capacity throughout the system, from transmission through distribution. Transmission system losses are eliminated, and distribution system losses are reduced. Some customer facilities have DGs that are installed for back-up power. These DGs are employed during grid-power outages or periods of high- cost grid power. They are operated for only a small fraction of time over the year. Moreover, back-up DGs are usually oversized, which means that they can provide more power than their facility loads need. These DGs can be equipped with a set of devices that will enable them to seamless interconnect to the grid and be dispatched if needed. The available capacity from such DGs can then be used for utility purposes.

[7] *Electrical Distribution Design, Inc.* Blacksburg, Virginia
[8] Department of Electrical Engineering Virginia Polytechnic Institute and State University. Blacksburg, Virginia

Distributed generation systems can operate connected to the grid or “standing-alone”. In the first case they rely on the electric grid to establish operating voltage and frequency while in the latter generators can operate independently of electric grid parameters. This last case is also known as *islanding*.

Whenever both of them need to connect to the grid, important conditions have to be assured as for example the same phase for voltage and current phasors. For this reason many types of protections are installed in these generators plants, for example:

- Maximum/minimum current/voltage protections;
- Maximum frequency range protection;
- Maximum reactive power flow protection;
- Phase shift of voltage phasor protection . . .

Obviously a DG system can be asked to work on island during critical periods, even if it’s regularly connected to the grid; this lets the DSO focusing only on consumers without DG during high power demand periods. Besides all the safety constraints to consider when connecting to the grid, it must be said that DR can be divided in passive and active generation. Passive generation is relative to technologies that can’t control neither the generated power and the output one (as photo- voltaic and wind power): indeed they rely on the available amount of light and wind. For this reason passive generation cannot be dispatched, i.e. the output power can’t be regulated to better match the demand curve. Active generation instead presents control over input fuel and output power, such as fuel cells or micro-turbines. For this reason they can be used for dispatching.

Insertion of DG into the existing electric grids implies an update of the network itself and its devices (mostly supposed to operate with only passive users) in order to have fast, economic and reliable instruments. Moreover, new laws able to deal with new power exchanges scenarios will be needed, as much as a trustworthy institution whose work will be protect users and operator guaranteeing fair remunerations and energy prices. Some studies focused on the technical issues of DG. A particular one concerns the relation between losses and power factor: in this case, a high pf (power factor) doesn’t imply low losses [26] and [27].

It leads to the conclusion that DG, as other new technologies facing old equipment, needs to be studied with accurate simulations and analyses even when intuition suggests no further calculations are needed. It is the case demonstrated in [28]: it was discussed how an apparently useless measure as over-compensation of power factor brings to the injection of huge reactive power fluxes into the grid during the night.

As a conclusion, all people involved into the DG field will have to deal with technical, juridical, environmental, economic issues in order to make the future grid work in the most efficient way.

2.3 AGGREGATORS

Distributed generation and demand response combined are helpful tools to improve business models, i.e. they allow to remunerate both active and passive end-users in the smart grids context. This is possible, for example, making them buy energy at its real-time price. Since this operation brings financial risks that end-users don't want to be exposed to, a new figure able to shield users is required. A solution is represented by the "aggregator" figure. That figure, who can be identified also as a "virtual power player" (VPP), is supposed to cluster small users' DR programs and interface with the DSO to communicate users' schedules: in fact, a VPP can aggregate Distributed Generation and DR small size resources in order to use them as a large scale resource in the electricity market [29]. As said in [30], a VPP could be able to transact energy to the main grid, both absorbing it during high demand periods and injecting it when generation exceeds consumption. At the end of the operation, VPP has to remunerate units according to their contributions.

VPPs represent a safe choice for small end-users, in fact these consumers [31]:

- should constantly monitor the market;
- should be always kept updated with all markets information
- don't have proper infrastructures (e.g. smart metering systems at the endpoints);
- have the possibility to run fewer financial risks.

In [31] REPs (retail electricity providers) are mentioned instead of aggregators but their roles are quite the same. REPs in fact can be seen as load aggregators or electricity suppliers able to connect end-users to the wholesale market. For that reason, it must essential for them to be economically covered with contracts both with the supply side (in the pool market) and the demand side (in retail market). A combination of approaches can be done in order to better manage financial risks and remunerate end-users. One remuneration method consists in paying the maximum tariff of each group in which users were previously divided: for this reason the overall system is not economically optimized, there- fore other ways have to be studied.

Several remuneration approaches have been presented in the literature [32] as the proportionality method, the equal percentage method and the factor G method: for all these methods a completely knowledge of information about every part involved is required. Lastly, another problem is represented by how groups are defined, i.e. the clustering operation.

2.3.1 CLUSTERING

Cluster computation can be based on one of the following methods [32]: the first one uses a *hierarchical algorithm*, showed in Fig.2.5 while the other one uses the *fuzzy C-means* method.

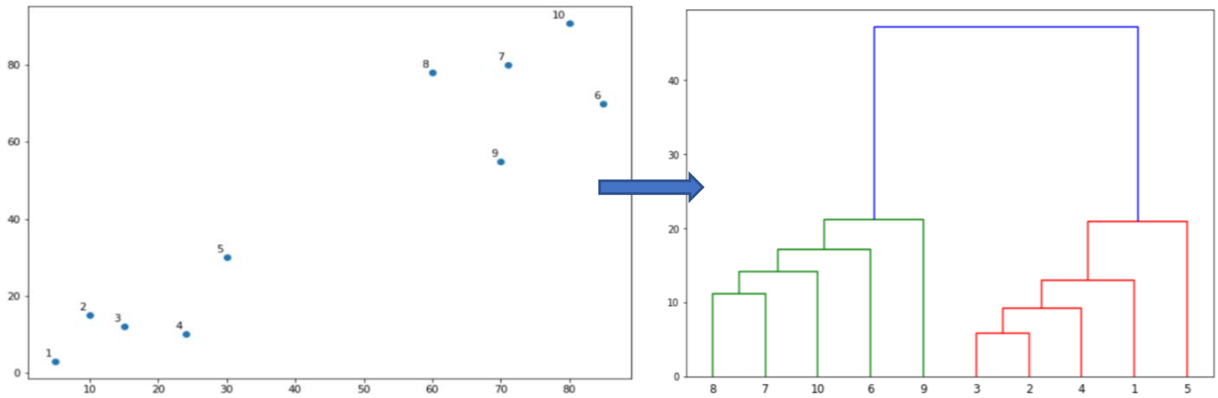

Figure 2-5: Example of how a clustering method works [33]

Hierarchical algorithm aims to obtain a hierarchy of clusters. A sequence of partitions is made in which each partition is nested into the next one in the sequence. Clusters are then formed in the form of a tree or hierarchy [34]. Starting for example from a set on N items, the most similar/closest pair is merged into a single cluster in order to get N-1 items totally. This iterative process is repeated until the imposed maximum number of clusters are computed. A computational tool commonly used the *cluster* function in MATLAB.

The *fuzzy C-means* can be implemented too in MATLAB (*fcm* function). It is simpler than the previous one since it only needs a data matrix and the desired number of groups as input.

Actually another method of clustering exists, known as *K-means* (Fig.2.6). The first step consists in setting a number k of clusters. The main idea is to define k centroids, one for every cluster; and at each iteration distances between objects and all the centroids (that are randomly set) are computed. Every object is then associated to the nearest centroid, forming groups. Once it is done, new centroids have to be computed according to the distances among the objects inside that group. The iteration process stops when centroids don't move anymore.

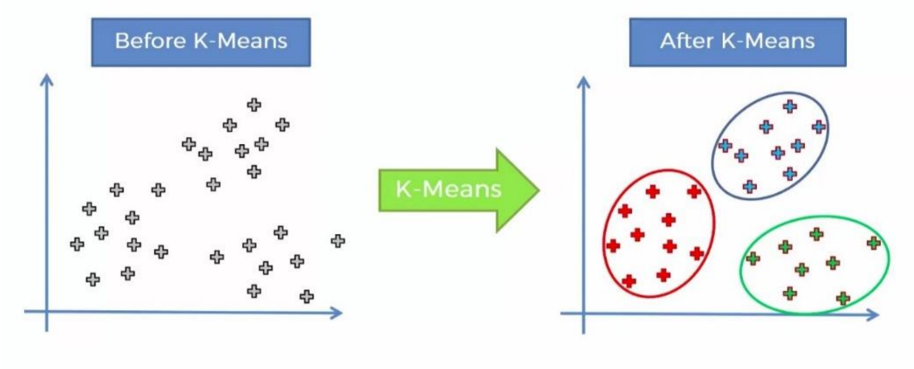

Figure 2-6: Example of k-means clustering method [35]

2.3.2 REMUNERATIONS

Choosing how to remunerate users who participate DR programs is one of the biggest challenges for a Virtual Power Player (VPP). Lot of ways are possible, but it must be kept in mind that VPP's aim is to minimize overall operation costs. Results reported in [32] show total remuneration is less expensive for VPP when considering it by type of resource: obviously, if creating separate groups of sources implies huge computational costs, this approach has to be avoided. One of the easiest ways to remunerate sources is the "maximum price per group" remuneration, as it is used in [36]: it's not the most economic but it doesn't imply high computational costs.

Another possibility is represented by the "proportional remuneration" that despite sounds the fairest one it requires lot of computational costs since each source's contribution has to be computed. At last, the "Pareto optimal solution" can be used as a remuneration method: in this case consumer's surplus is at its maximum value and no one can improve his welfare without damaging others'.

2.4 ELECTRIC SYSTEM

The electric system is defined as the whole of machines, devices and transmission lines able to produce, transform and transmit electrical energy from power sources to consumers (Fig.2.7).

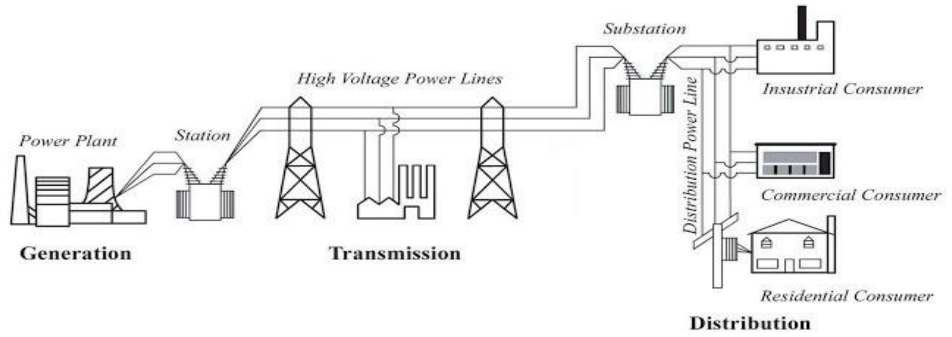

Figure 2-7: Traditional scheme of an electric system

Since electricity doesn't exist as a natural resource, it's necessary to produce it. This process can take place in localized power plants or in distributed generation stations that use renewable sources. This latter option is quite recent and started to have influence on the electric system and market only in the last decades. Before that time electric system didn't face important technological improvements such as smart grids: that is the reason why this new resource is proving people who work in this field with new challenges that deal with technical, juridical and economical constraints.

There are different reasons for introducing new types of power sources into the electric system. For example, enabling the insertion of new electricity sources is one of the main reasons that brought to electricity market deregulation: the presence of more market players increases competition and, together with an increased production capacity, it results in prices reduction. Anyway, price of electricity produced by large conventional installations as fossil fuels and nuclear power plants is still too low for small units to be competitive [37].

Another reason for introducing new types of power generation is related to environmental issues: most of the conventional types of power plants emit carbon dioxide and other pollution gasses that dangerously increase global warming. Despite not all the conventional power stations produce carbon dioxide, environment and people's health can be still exposed to that risks being pollution not localized only where power plants stand. For example, radioactive waste even from old nuclear power stations still represents a serious issue and large hydro-power's reservoirs impact environment in an irreversible way.

A third reason for supporting small size “green” producers[9] is represented by the power gap that every day occurs between consumption and production: a better match between the two curves can be reached thanks to the more precision available avoiding to waste money in large investments that only deliver huge blocks of power and take 10 or more years to be completed. Despite green sources total costs may be higher, investments would be spread over many owners resulting in a doable way of financing this kind of technologies [37].

Until now it has been said that green power sources (the so called “RES”, Renewable Energy Sources) can be competitive against fossil fuels plants, despite more in the long terms rather than in short ones. Focusing now on the transmission part, namely once energy is produced, it is fundamental to talk about new power lines construction. Installing new power lines that connect generator to users is often cheaper than building new power stations, that’s why it can be a very attractive solution. Since in most of the countries there’s not anymore a single entity in charge to control electricity production, transmission and distribution, that solution is very welcomed. Obviously, it is not only a matter of technical constraints. Also political, legal, financial and social aspects have to be taken into account (some studies focused on the impact of electro- magnetic waves produced by power transmission lines on human body [38], [39]).

During the last two decades it has appeared of very high importance to develop a new system of grids able to take advantage of both electronic and telecommunication benefits. A transmission system able to connect users with grid operators and let them communicate their load conditions in order to better optimize power fluxes. That’s what a smart grid is supposed to be; in this scenario a player called “aggregator” will have the role of collecting small users’ information and dialogue with the Distribution System Operator (DSO). As a consequence, a high technological environment is needed, also because energy markets operate in real time and a fast and secure way to transmit information is essential. Fortunately, most of that required technologies are already under development since they’re used in other fields as communication and monitoring/control [6].

[9] In literature small hydro power refers to units varying from 10kW to about 30MW. Sometimes they are classified as micro hydro (10–100 kW), mini hydro (100–500 kW), and small hydro (500 kW–30 MW) [37].

2.5 ELECTRICITY MARKET

Countries that don't present a monopoly in energetic sector are characterized by an electricity market where players are involved and act in a competitive environment: this is supposed to be the way to increase power efficiency and reduce prices of the overall electric system.

As presented in [20], electric energy is a commodity for which balance between demand and offer must be assured in any moment. That mandatory constraint makes inefficient the usual rules used with commodities markets; moreover, the impossibility to store energy in proper quantities makes the electric market very active. Price of electrical energy indeed is given by the intersection point of demand and offer curves and can vary lot of times during the day.

Demand Response appears as a promising tool to keep power flows balanced without high operational costs as will be discussed in the next paragraphs.

Energy costs consider several parameters, both concerning the production phase and the transmission one (construction or preservation of lines among others). Focusing on production costs, it must be reminded that they're composed of a fixed component and a variable one. The first one comprehends all factors that don't depend on the amount of sold energy: salaries, loans, leasing, return on investments are some of them. The variable component instead is proportional to production, as fuel's and materials' costs. The sum of both of them gives the minimum price an industrial activity has to present to the market in order to get a rent. According to this price a bid is made by the generator: the best producers' prices are selected by the market and they have to produce the offered power.

This operation is called *despatching*. Besides the maximum power that a generating plant is able to offer, other constraints have to be considered such as lines losses (due to Joule effect) and lines' congestions (that determine the maximum power that can flow in a specific line).

There are two models of electricity market: Power Exchange and Pool.

The *Power Exchange (PX)* model presents several markets that work on different time segments: all of them take place before the day T for which the power is being sold. This market model presents two trading modalities: the first one is constituted by a platform where blocks of power are traded for specific hours of the day/week, while the second one is the balancing market, necessary to maintain demand and supply always matched. Focusing on the balancing market, it must be said that both generators and demand units can participate by varying generated power or by reducing loads. That allows to keep the grid stable and to cap energy prices. In this field, an important role is played by aggregators as they are supposed to converge power coming from numerous small generators: these generators in fact deal with the DSO (Distribution System Operator) through the aggregator, who remunerate them according to the exchanged power or loads curtailments. Since the aggregator figure will play an important role in future electricity markets, a deeper description will be done in the next paragraphs. As mentioned before, in the PX market both blocks of power and real time power are exchanged. Blocks are traded through the mean of bilateral contracts that allow to cover most of the forecast demand curve; anyway, in order to perfectly match demand and offer at any instant, real time power has to be traded too.

Pool market model is a compulsory exchange where all generators can produce only if grid operator tells them so. Electricity price is set by crossing demand and supply curves, therefore is always changing during the day. Since this represents economic instability, some tools to avoid excessive risks have been implemented: in pool market the "contract for differences" is one of them. It consists in having a "spot price" taken as reference and considering the actual price of the energy: if the actual price is higher than the spot price then the producer is selling at a bigger price than the one settled and the difference will go to the purchaser. Vice versa, if purchaser buys energy at a lower price than the spot one, he is supposed to give the difference back to the producer.

Also, power exchange market presents a tool that guarantees protection for both consumers and generators, i.e. the bilateral contract. By signing it, a capacity is committed for a given time: the purchaser indeed is expected to buy an amount of capacity for a settled quantity and price from the producer.

Markets in Power Exchange

As previously said, PX market is composed by further markets that take place in different moments before and during the day T for which the capacity is being sold. Here some electric markets will be listed as they work in the Italian context, since the structure is quite similar to most of the non-vertically integrated markets.

The *day ahead market* has to select the operating power plants for the following day. It receives bids and offers from operators and list them according to a merit order (i.e. generators with lowest production costs will be operated in preference to others). It also receives consumers offers in order to better foresee the load curve of the day after. Generally this market it's scheduled for each hour of the following day, therefore a producer can make up to 24 bids. It's named after the closing day, that happens to be the day before the T day. It's open well ahead the T day, even one week earlier. A specific commercial institution manages it and tells the TSO (Transmission System Operator) which power stations are going to be operative.

The *adjustment market* presents the same structure as the day ahead market, but it opens after its closure. It's supposed to be used to adjust generation profiles in order to better match the demand curve.

The *infra-daily market* opens once the previous two are closed. It's aimed at adjusting again the power that's going to be produced/requested until few hours earlier of the power exchange moment. It's composed by sessions (up to 24) as the day ahead market. Sessions are organized as implicit auctions with different closing time and in sequence.

The *balancing market* collects the prices that producers and consumers intend to get since they are going to change their power profiles. TSO then put them in a merit order and will call them according to the real time needs: traded capacity is known only afterwards then.

The *ancillary services market* can be supplied or through long term contracts or in the daily market. Ancillary services are related to load balancing, the three types of reserve (primary, secondary and tertiary), losses, reactive power regulation and black start service (for black-out events). A power station can operate only in this type of market since the remuneration can be as the same level as the other markets. This market starts when the others are closed.

Market for capacity represents an alternative way for the generators to be paid. In fact they are paid according to the capacity made available, that is not necessarily used.

2.6 CONCLUSIONS

In this chapter it has been presented an overview of the state of the art about Demand Response and the context in which it can flourish (Distributed Generation). Some types of remunerations have been presented, showing that every scenario has its own way to apply remuneration (according to user voltage, load type, how much loss of comfort is possible for the consumer are some conditions). Since big amounts of data and information about power exchanges are going to be analysed in this high-developed field, figures able to gather and manage them will assume lot of importance. That's why some clustering methods and, more in general, aggregators, have been presented. Finally, electricity market structure has been discussed, showing some market types since DR can be a tool that fits all of them.

3 Elasticity

As already explained in the introduction, this chapter is dedicated to elasticity parameter definition. Its mathematical expression is given and explained; moreover some conceptual variations made by experts in the past (especially in the economy field) are reported because they may inspire a new work similar to this one.

3.1 DEFINITION

As already introduced, elasticity is defined by the formula 3.1

$$e = \frac{\Delta Q/Q}{\Delta P/P} \quad (3.1)$$

where Q represents the initial demanded quantity, ΔQ its variation, P the initial price and ΔP its variation. Elasticity is then computed as the relative change in quantity over the relative change in price, representing the availability of a user to vary its power absorption after a remuneration.

Two types of price elasticity are defined in literature: *own-price* elasticity and *substitution* (or *cross*) elasticity. The first one can reveal how customers adjust their consumptions after increases in prices of electricity: it might result useful to evaluate long-term adjustments to changes in electricity prices. The second one instead focuses on how consumers substitute one good for another or how they switch periods of consumptions after price variations.

By analyzing own-price elasticity curves, two different kinds have been defined: if demanded quantity responds to price changes in a greater than proportional manner the curve is said to be *elastic* (e>1). Otherwise, an *inelastic* demand curve represents a situation in which a percentage variation in price will causes a smaller percentage change in quantity demanded (e<1) [40]. For a commodity the range of inelasticity is usually between 0 and 1 while the elastic range begins with values greater than 1.

Elasticity value depends on the type of consumer and other factors as climate, day of the week and load's conditions and localization [32]. Anyway, that value may be not constant in time. For this reason the *short-run* elasticity and *long-run* elasticity terms have been introduced[10]:

- *short-run* elasticity describes the price-response from the system with its current infrastructure and equipment [41];

- *long-run* elasticity considers those investments that can be made in response to higher prices [41].

Their values can be very different as lot of factors influence the long-run one: industrial sector in particular is very price-sensitive due to its high electricity consumptions. Burke and Abayasekara [42] found that in the US short-run elasticity presents values around -0.1 for any type of user (residential, commercial, industrial); long-run elasticity instead appears to be much larger, around -1.0, specially for the industrial sector[11].

Elasticity estimation represents a challenge for everyone who wants to study scenarios that involve Demand Response: basing on that estimations it is possible to predict how every category of user is going to change its power absorption in the short/long time. By knowing that profiles, the entire electric system can benefit shifting loads from periods where the generation availability is lacking to others when it is abundant. As a result, all the available power is used in each moment of the day maintaining the system balanced. Other aspects have to be considered. First of all, the socio-economic impact, as people can change their habits following social models or trends. Political choices contribute too to make people variate energy consumptions, in order to better achieve environmental goals or energy efficiency in general.

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[10] Despite these terms were introduced into the economy field, they can be applied in this context too.
[11] In this report only absolute values are considered in order to do better comparisons. Positive values are given indeed by a consumer point of view remuneration. Vice versa, negative are from a DNO's.

3.2 ELASTICITY EVALUATION

A good elasticity evaluation allows to better match power production and demand curves in every moment along the 24 hours. Elasticity is indeed a parameter strictly related to each type of consumer, his habits, weather forecasts, time and location [32]. Until now only fixed or estimated values have been used [43]: moreover, these values cover ranges that can be very wide. Hyndman and Fan [44] collected data from past studies that dealt with elasticity definition. Their conclusion is that all data from different sources "are not very consistent" since for short-term elasticity numbers range from -0.2 to -0.4 while for long-term elasticity from - 0.5 to -0.7 (Table 3.1[12]).

Because of that, it may be interesting to define precise values able to follow users' conditions day by day. It has been proved that important advantages would derive from that:

- optimal use of available power in the grid avoiding congestions;
- reduced volatility of nodal spot price [11];
- reduce exceeding power production saving fuel and avoiding machine damages;
- diminish power production from carbon plants with environmental benefits;
- power exchanges with neighbor markets are reduced giving more political and economic independence to each region/country;

[12] All data are taken from studies made before 2007. Since DR programs and Renewable Energies started to strongly influence market/politics especially in the last decade (after 2010), these values can be very different from the actual context.

Table 3-1: Summary of the literature on price elasticity end-users

Researcher	Year	Region	Sector	Elasticity
Bohi & Zimmerman	1984	U.S.	Residential, industrial and commercial	For residential only short-run: -0.2 long-run: -0.7
Filippini	1999	Swiss (40 cities)	Aggregation	-0.3
Beenstock et al.	1999	Israel	Residential and industrial	Residential: from -0.21 to -0.58 Industrial: from -0.002 to -0.44
NIER (National Inst. of Economic and Industrial Research)	2007	Australia	Residential, industrial and commercial	Residential: 0.25 Industrial:0.38 Commercial: 0.35
King & Shatrawka	1997	England	Residential and industrial	From 0.1 to 0.2
Patrick & Wolak	1997	England and Wales	Industrial and commercial	Water supply industry: from -0.142 to -0.27
King & Chatterjee	2003	California	Residential and commercial	From -0.1 to -0.4
Reiss	2005	California	Residential	-0.39
Faruqui & Georg e	2005	California	Residential, industrial and commercial	Reducing consumptions in peak-periods following RTP: 0.09
Taylor et al.	2005	U.K.	Industrial	From -0.05 to -0.26

3.3 CONCLUSIONS

Elasticity evaluation importance has been justified after showing its definition. At the end, in section 3.2, it has been explained why new values are needed, especially values that follow power demand trend and are able to update continuously along the day. All values showed are indeed taken from papers before 2010: new green politics, new consumers' habits and new possibilities have been influenced energy world from that year (e.g. the incrementing penetration of electric vehicles, smart meters, roadmaps that aims at diminishing pollution…), therefore those values need to be updated.

4 Developed Methods

In this chapter it is discussed the method adopted to obtain elasticity from graphs and how that value can be used to make demand curve more predictable.

Data relative to Portuguese power production and consumption of different users divided on their voltage level[13] have been analyzed. Three main sections divide the final work:

1. Proof that elasticity can be obtained from ΔP-ΔQ plots;
2. Consequences of elasticity estimation errors;
3. Elasticity change from weekday to weekends.

Section 1: Getting elasticity from plots

Price and power absorption variations are considered because elasticity is defined as the ratio of their relative variations before and after DR. As said in [6], response of consumers to price variations should not be assumed as totally flexible since constraints as maximum load reduction, price caps, load and generation balance are present; these constraints will not be considered because for now the only goal is to explain how to obtain elasticity from graphs. A plot that represents a ΔP/P trend over ΔQ/Q is characterized by an angular coefficient that is

[13] MAT, AT, MT, BTE, BTN-2, BTN- 1.

the reciprocal of elasticity. It can be seen comparing equation 4.1 with 4.2.

$$e = \frac{\Delta Q/Q}{\Delta P/P} \tag{4.1}$$

$$slope = \frac{\Delta P/P}{\Delta Q/Q} = \frac{1}{e} \tag{4.2}$$

Sometimes in literature positive signs for elasticity are reported, sometimes negative ones. This is because signs of slopes are related to ΔP definition[14]. Negative elasticity sign indicates that consumption reduces after an increase in price and positive signs indicates the reverse case [17].

Elasticity was found by making up scenarios of DR. In particular, an increasing power limit cap was used: 10-15-20-25% of load reduction was indeed imposed. In every case the exceeding power is supposed to be paid at the medium tariff instead of the most expensive one in order to get the ΔP and ΔQ required for the calculation. To compute elasticity (4.3) has been used.

$$e = \frac{\Delta Q/Q}{\Delta P/P} \tag{4.3}$$

Obviously, the reverse thinking can be done, i.e. obtaining ΔP/P values starting from ΔQ/Q. It would be a different case from what presented previously since in this last case different scenarios relative to the overall Portuguese power are considered and not each different user type. The last quantity to be defined is Q_{fin}, given by equation 4.4, obtained adjusting 4.3:

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \tag{4.4}$$

Focusing on plot construction, it is known that *e* constitutes the slope of lines: this factor, together with 2 points which the line passes through, gives the plot for each DR scenario. Using regressions equations, relative price variations ΔP/P can be used as input to compute relative power variations ΔQ/Q (since Q_{in} would be a known parameter too, it's easy to get Q_{fin}).

This first step demonstrated that elasticity value can be derived from real data. As already said, most of the times values from non-updated tables are used to classify end-users: obtaining elasticity from actual consumption data instead allows to deal with more precise values.

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[14] ΔP is given by the difference of final price P_{fin} (after DR) minus initial price P_{in} (before DR); if price decreases, ΔP assumes negative sign.

Section 2: Impacts of wrong estimations of elasticity

Having an elasticity value for each user type allows the DNO to estimate how much power is available thanks to DR program during a specific event. Unfortunately, inaccurate estimations can occur: consequences both on ΔP and ΔQ evaluations are then to be considered. In the first case users could expect to be remunerated with another value of ΔP while in the second case the actual available power for the DNO would be different from the predicted one.

The following procedure has been adopted, represented in Fig.4.1.

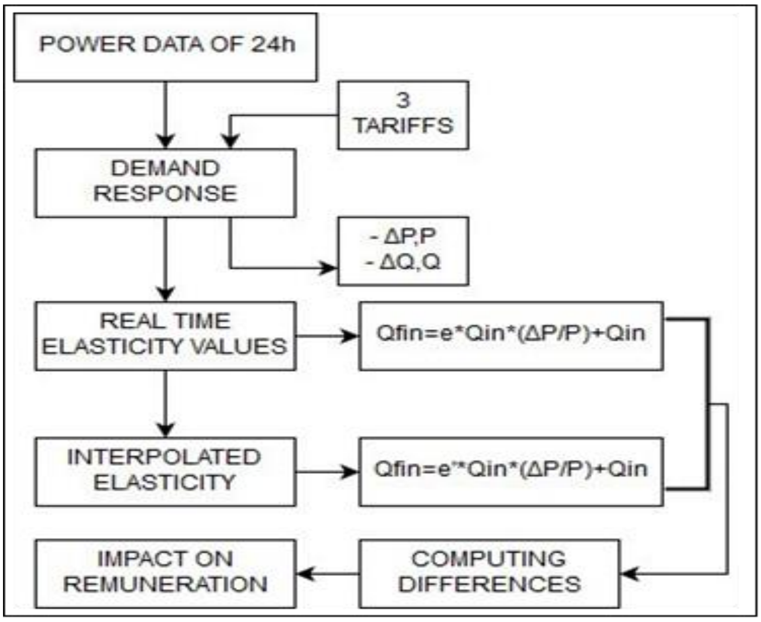

Figure 4-1: Scheme of algorithm used to evaluate error on remuneration

The three tariffs scheduled over the day (according to the triple tariff contract) are plotted together with power consumption trend. In this way it is possible to define specific DR programs able to focus on different parts of the day where high consumptions coincide with peak tariff. More than one scenario are possible, depending on how energy needs to be moved into "valley energy" hours and how to remunerate consumers. Figure 4.2 at the end of this section shows all possible choices considered by the author. Only initial conditions would differ between scenarios since after imposing them, elasticity computation and saving calculations algorithms would be the same.

In particular, "scenario A" consists in applying a power cap to consumptions: if they exceed that limit, DR program starts and power reduction is imposed. In this case power cap is chosen to be 115% of the average power absorbed during the day, in order to have a value proportionate to every user. At this point, as for all other scenarios, it has to be decided whether moving energy to a less expensive period or simply reduce consumption. This last choice represents a more drastic change to consumers' habits but allows them to save more money.

Once obtained ΔP[15] and ΔQ[16] is possible to evaluate elasticity. That value is computed every 15 minutes since consumptions are measured by that time. This allows to have more elasticity values following power trend and not a single value for all day. Once elasticity is found, it can be used to evaluate Q_{fin}.

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \tag{4.5}$$

Since this work aims to define a way to predict consumptions starting from given elasticities, a model is needed. That is why elasticity values have been modeled by mean of interpolating functions: the equation that has been found is supposed to be used by DNOs to predict their consumers' behavior. In order to see the reliability of the interpolation, MAPE value is computed taking as input "real" elasticities values and interpolated ones.

$$MAPE = \frac{100\%}{n} * \sum_{i=1}^{n} \left| \frac{Ai - Fi}{Ai} \right| \tag{4.6}$$

In order to have a feedback from an economic perspective, Q_{fin} is found by mean of 4.6 with the new elasticity values and the overall costs are computed basing on these new power values.

New Q_{fin} values are used to compute ΔQ, since Q_{in} is the same as before. ΔQ is then used as input in ΔP-ΔQ plots taken from literature in order to find ΔP.

The con of this method ("scenario A") is that it's based on historic estimations, needed to evaluate the average power used as cap. They may be different from real-time consumptions, so the model can be inaccurate.

Scenario B and C need to be mentioned, as they can be applied in real cases too. The first one imposes a power cap during peak tariff period. That power cap is 15-20-25% of the contracted power, therefore no historic data are needed. Also in this case energy can be shifted to other periods, so consumers wouldn't lose too much comfort having the same amount of energy

[15] Given by the highest tariff minus the one used to remunerate the consumer.
[16] Given by the load reduction.

during the day. This solution is more expensive as one could have expected. According to scenario C instead, power consumption is increased during low tariff periods in order to reduce consumption during high ones. Again, total energy can be conserved over the 24h.

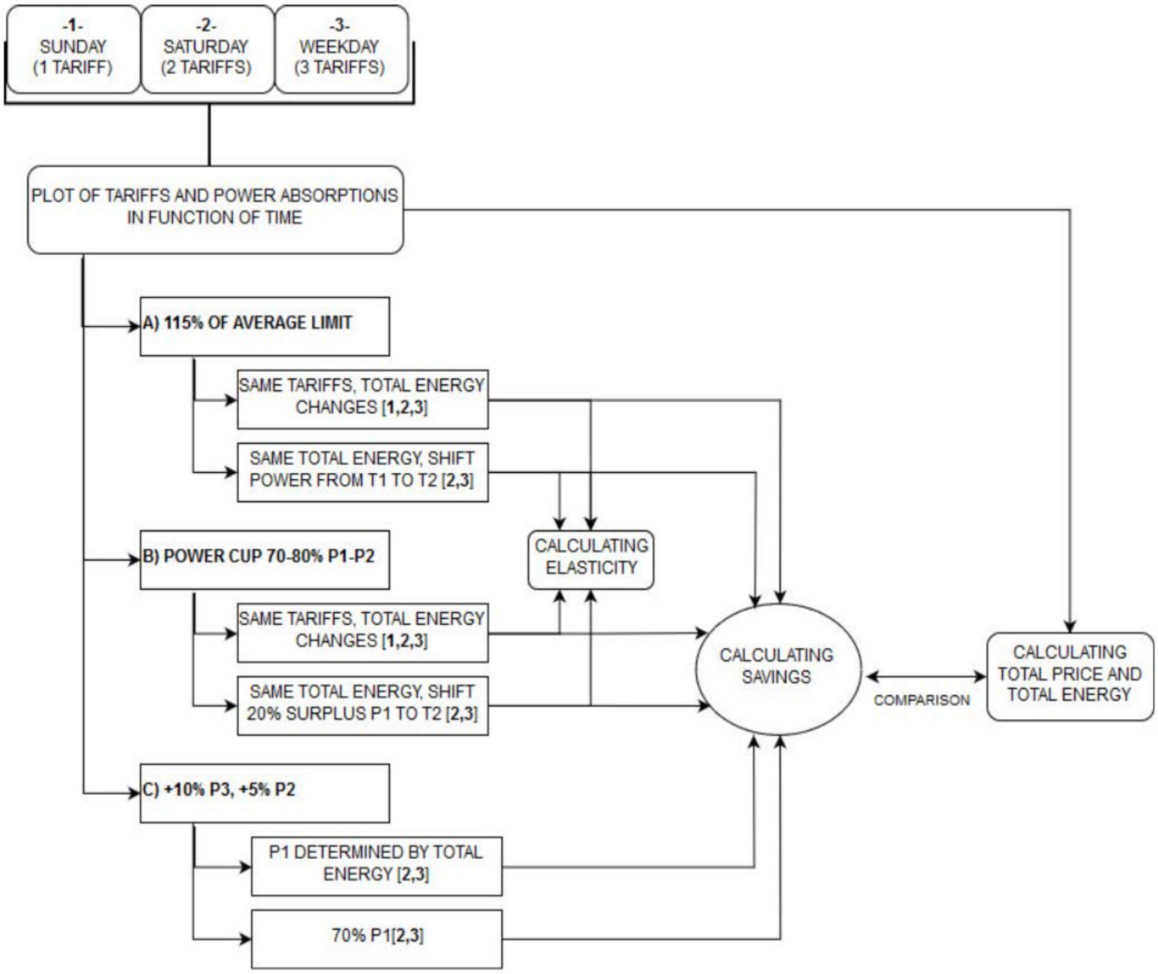

Figure 4-2: Representation of application of possible scenarios

Section 3: Elasticity on weekdays and weekends

Considerations about elasticity evolution through the week have been done. During the week it was stated that in particular time frames elasticity evolves according to load reduction and remunerations values. During weekends instead, elasticity is not easily definable since not always multiple tariffs are present (on Sundays only one is present) and on Saturday only two tariffs blocks divide the day: one for the day and the other for the night. Consumers simply diminish power absorptions if they want to save money, not because they are asked to. Therefore it is not properly correct to talk about DR, also because ΔP is not as big as during the week.

4.1 CONCLUSIONS

This chapter is supposed to be used as a reference for whoever is interested in developing scenarios/methods similar to the ones used in this work. This chapter presented the study in general terms, explaining what is going to be discussed in the following chapter (where real data are used). Different sections are shown separately in order to better understand each tool's applications. It has been chosen to present the work as a succession of steps in order to better guide who wants to follow a detailed procedure in this kind of study.

5 Numerical Analysis

In this chapter results obtained working on Portuguese grid data are presented. The algorithms used have been already explained in previous section but some descriptions are given again in order to better comprehend numeric results.

5.1 APPLICATION OF DR PROGRAM TO GET ELASTICITY

Section 1: Getting elasticity from plots

It has been already showed that elasticity is the reciprocal of slope in ΔP/P-ΔQ/Q plots. Figure 5.1 represents points taken from real data, for each user type, and their interpolations. Six classifications between users are present, but only 5 interpolating lines are showed: this is because BTE and BTN-2 users' consumptions are equal, so their respective lines are overlying. BTN-2 consumptions alter elasticity estimation too, as can be seen in Table 5.1. It lists lines' slopes, elasticity obtained from them and "original" values[17] to be used as comparison. Since there's not sensible difference between computed values and the given ones (last 2 columns), the reliability of the analytical method is demonstrated.

In Tab.5.1 absolute values of elasticities are reported in order to do an easier comparison with the input data (reported in the last column).

[17] Used by Portuguese grid operator.

Table 5-1: Values of slope and elasticity

User type	*slope*	|*e*|	*Original e value*
MAT	-1.887	0.52999788	0.53
AT	-2.222	0.45000450	0.45
MT	-2.439	0.41000410	0.41
BTE	-2.703	0.37000037	0.37
BTN-2	-2.703	0.30000009	0.37
BTN-1	-3.704	0.27000027	0.27

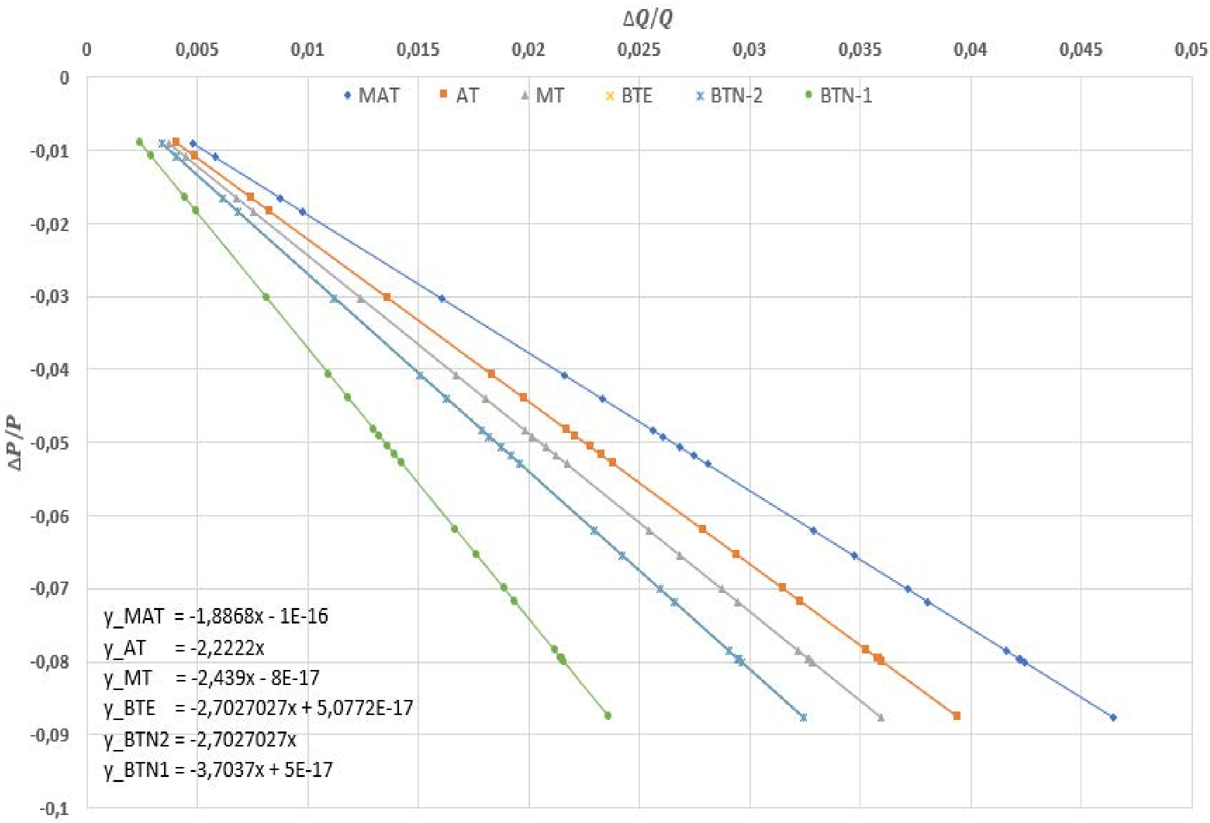

Figure 5-1: ΔP/P over ΔQ/Q plot for each type of user

Figure 5.1 shows ΔP/P as function of ΔQ/Q, that is used as input in that case. Elasticity was then found by computing lines' slopes. What if the DNO wanted to know how much power is going to be available after a specific remuneration ΔP? Remuneration ΔP would now represent the input value and ΔQ the output one. In this case, elasticity, ΔP and Q_{in} are needed in order to plot lines from which evaluate ΔQ (as shown in Figure 5.2). Elasticity was found by making up a DR scenario: an increasing power limit cap to load profile by 10%, 15%, 20% and 25 was imposed (that also allows to compute Q_{fin} and ΔQ since Q_{in} is already given). In each case the exceeding power is supposed to be paid at the medium tariff instead of the most expensive one, therefore also ΔP was defined, that is needed for the calculation.

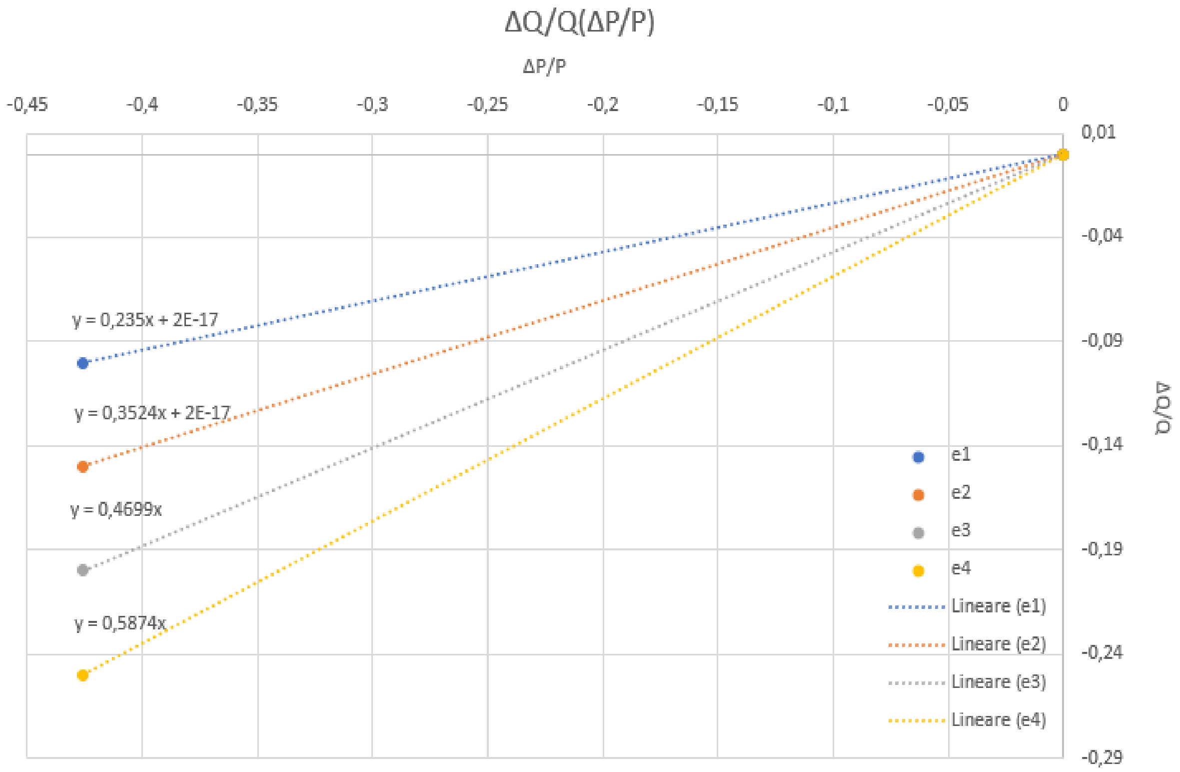

Figure 5-2: ΔQ/Q over ΔP/P plot for each scenario

To compute elasticity, the traditional formula has been used (5.1), that is here reported:

$$e = \frac{\Delta Q/Q}{\Delta P/P} \tag{5.1}$$

and the following values have been found for each case (Tab.5.2):

Table 5-2: Elasticity values for different DR programs

Power cut	10%	15%	20%	25%
Elasticity values	0.2349656	0.3524485	0.4699313	0.5874141

As it was expected, the more power cut (ΔQ), the more elastic the user results (keeping same ΔP[18]). It worth to be noticed that 20% would be an affordable load cut for some users and that would result in an elasticity value way higher than the usual (that is around 0.35).

The last quantity to be defined is Q_{fin}, given by the equation (5.2):

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \tag{5.2}$$

[18] ΔP value was constant and given by P_{fin}(=0.1571)-P_{in}(=0.2735) = -0.1164 [€/kWh].

ΔP/P is a fixed value (being the switching always from the most expensive tariff to the medium one) and is -0.42559415 [€/kWh]. The chosen Q_{in} is 4717.488421 [MW] (the number itself is a less important parameter since the final relation is the object of this section). These values together with elasticities give the following ΔQ/Q[19]: -0.10, -0.15, -0.20, -0.25.

Table 5-3: Coordinates to plot ΔQ/Q over ΔP/P

Power cut	**0**	**10%**	**15%**	**20%**	**25%**
Elasticity	**0**	**0.2349656**	**0.3524485**	**0.4699313**	**0.5874141**
ΔP/P (x)	0	-0.4255942	-0.4255942	-0.4255942	-0.4255942
ΔQ/Q (y)	0	-0.1	-0.15	-0.20	-0.25

Microsoft Excel's tools allowed to obtain regression lines' equations (showed in figure 5.2). Two of them present a constant term due to "machine accuracy": lines are indeed supposed to pass through axes origin (0;0). In any case, these constant terms are very small (magnitude around 10^{-17}) therefore they don't affect results.

Using regression equations, relative price variations can be used as input to compute relative power variations (since Q_{in} would be a known parameter too, these equations allow to find Q_{fin}).

[19] Since there's a linear relation between ΔP, ΔQ and *e*, it makes sense to obtain these values.

Section 2: Effects of wrong elasticity estimations on ΔP and ΔQ

This part of the work presents how elasticity was found starting from data consumption. Data from Portuguese grid were used. The adopted DR program was made up by the author. During the weekdays, 3 different tariffs are applied along the 24h; their values are shown in Table 5.4

Table 5-4: Classification of different tariff values

Tariffs classification	T1 - *Expensive*	T2 - *Medium*	T3 - *Cheap*
Prices [€/kWh]	0.2253	0.1765	0.1016

At the end of this chapter a table that summarizes tariff distribution over the day is presented. Now a graph (Fig. 5.3) shows tariff evolution over the 24h of a random week-day (from Monday to Friday) according to a Portuguese DNO (EDP).

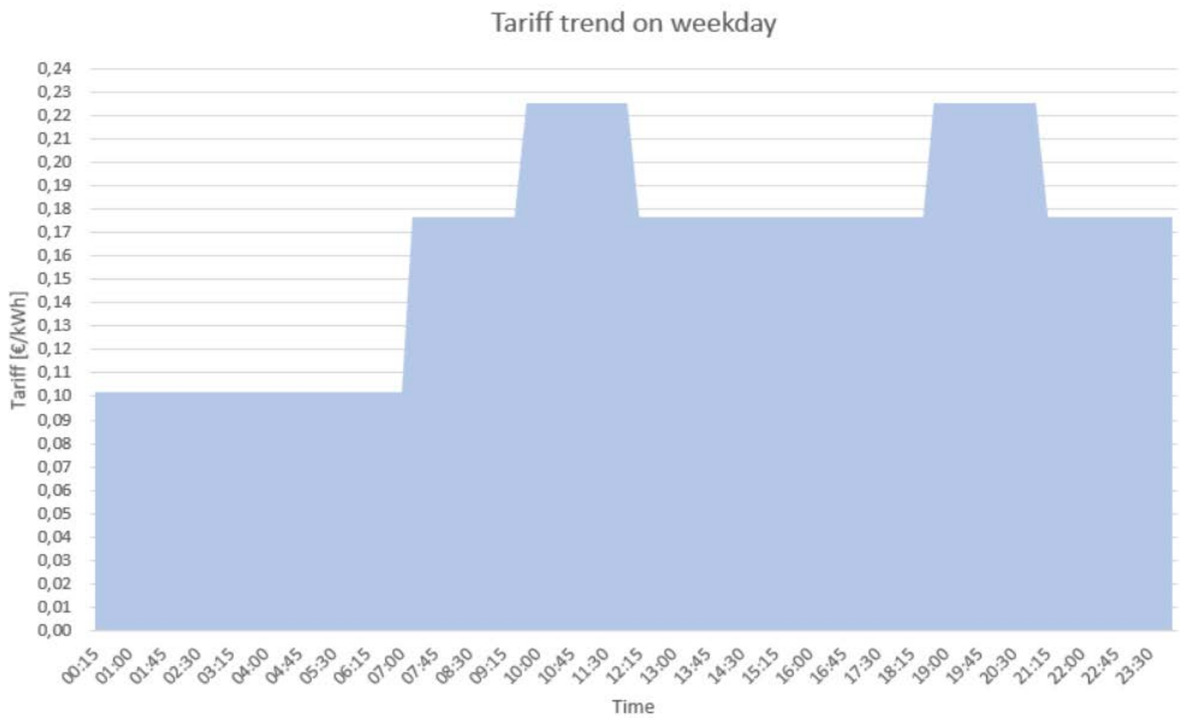

Figure 5-3: Graph of tariff trend along the day

Tariffs follow power demand trend, in fact they are supposed to incentivize energy consumption when it's available in high quantity. Figure 5.4 shows power consumption trend (orange line): some improvements can be done, especially from 18:45 to 22:15 where high consumptions coincide with tariff peak for most of the time.

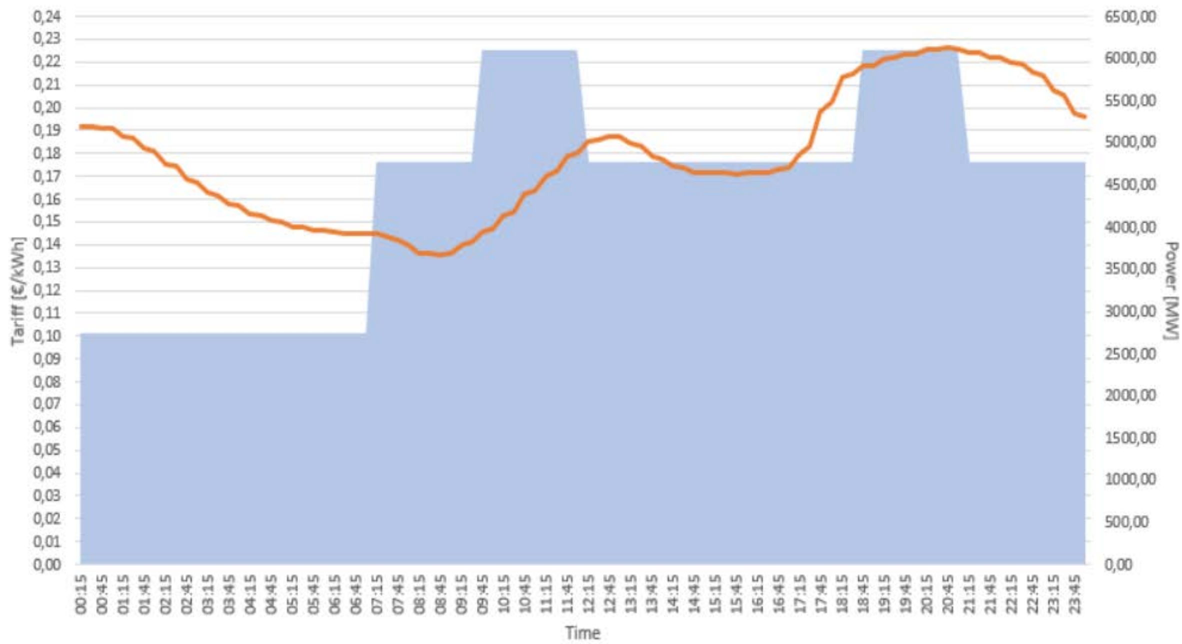

Figure 5-4: Graph of power trend along the day (Monday)

The following DR scenario was supposed by the author[20]: during high consumption periods, users' power has been cut. Power-cap limit was imposed to be the 115% of the power value averaged along the 24h of the day. It is supposed to be acceptable by most of the population since power reduction occurs only if high demand periods coincide with high tariff (so only a limit period of time). Moreover, calculations showed that not more than 12% of consumption has to be reduced.

Unfortunately there's one significant disadvantage of this method: average power (red line in Fig.5.5) is an estimation obtained from historic data. In fact all the measurements over the 24h are needed to compute the average power (and also its 115% value): the same day of the previous week can be considered, or the same day of the previous year, or simply the day before. All these possibilities present uncertainty related especially to weather conditions that can vary significantly from one day to another.

A potential improvement of this method is to impose a "minimum power cap" too in order to maintain absorbed power within a certain gap, e.g. ±15% of the average power. This would guarantee more balance from a grid point of view, allowing power plants to be more constant in electricity production (with benefits both in terms of costs and machine use). In that case end-users should be taught these benefits since they are not intuitive, in fact consumption during

[20] Previously presented as "Scenario A".

night hours would actually increase.

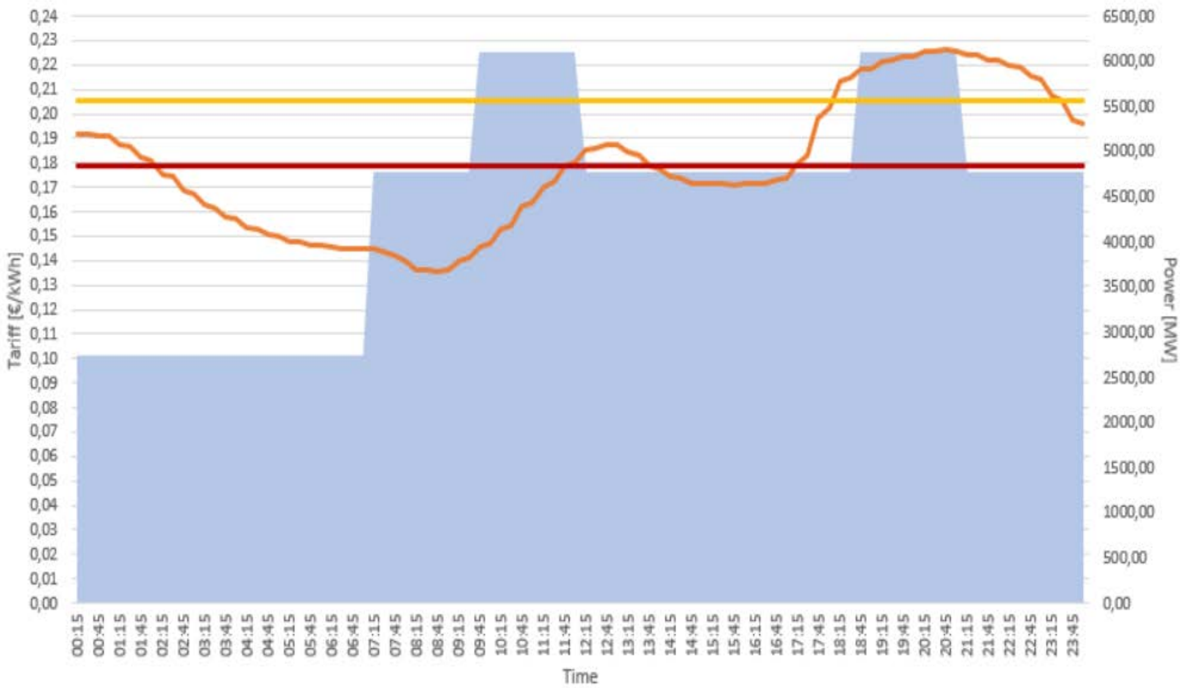

Figure 5-5: A Monday power trend, its average (red) and its 115% (yellow)

By applying this scenario, graph of Fig.5.6 is obtained. Yellow line represents the 115% of the average power and it is used as power cap: green line (power absorption in this case) is then limited when it would exceed that limit. That explains the flat section in the evening hours. In Appendix A instead, all consumption data are reported: every 15 minutes its relative tariff, power before DR and power after DR has been computed[21].

Power-cut is going to be the numerator of elasticity formula (5.1). For what concerns the denominator ΔP/P, an important consideration has to be said. P_{fin} is the price of the T2 tariff, while P_{in} is the most expensive one, T1. Therefore ΔP is given by 0,2253-0,1765=0,0488 [€/kWh]. This means that when consumption is above power cap (green flat part in Fig.5.6), T2 tariff is applied to limited power (instead of T1 to the actual consumption). Having ΔQ and ΔP allows to evaluate elasticity: obviously, it can be defined only during the DR period, namely the flat section. It has been chosen to pay the reduced power at T2 instead of T3 tariff because it could represent a money loss way too big for distribution operators: costs optimization in fact involves electric system as a whole, considering both consumers' and producers' interests.

[21] DR lasts from 18:15 to 23:30 as can be seen in the A Appendix (yellow cells on the right).

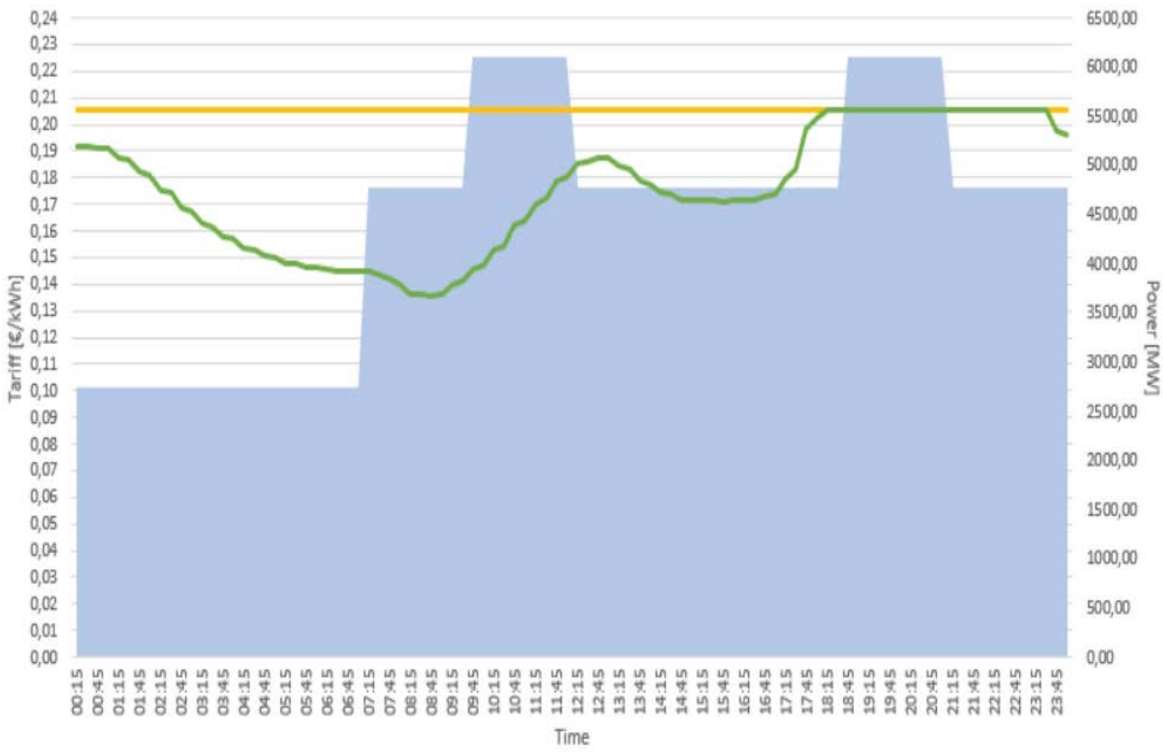

Figure 5-6: Power trend imposing the 115% cap

Proceeding with elasticity evaluation, computations brought these results (left column of Tab.5.5). They have been plotted (Fig.5.7) and the interpolating equation has been reported on the graph: it was used to compute interpolation points (right column of Table 5.5).

Table 5-5: Elasticity values during DR and their interpolations

Elasticity during DR	Interpolated elasticity values
0.272643	0.263143
0.278420	0.295166
0.332867	0.323482
0.343586	0.348092
0.373156	0.368995
0.374898	0.386192
0.406371	0.399682
0.412945	0.409465
0.422696	0.415542
0.410091	0.417913

A model has been created then. It is supposed to be used by the DNO to estimate how much power end-users are going to reduce during DR program.

In this work it has been evaluated how much an error in this estimation can influence in terms of ΔQ. In particular, Q_{fin} has been computed with interpolated values of elasticity and then compared with the "original" ones. Q_{fin} is given by equation 5.3, obtained from elasticity definition; original values and computed ones (during DR) are reported in Table 5.6.

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \tag{5.3}$$

There's not big difference between real Q_{fin} values and computed ones, proving that the found interpolation is quite precise.

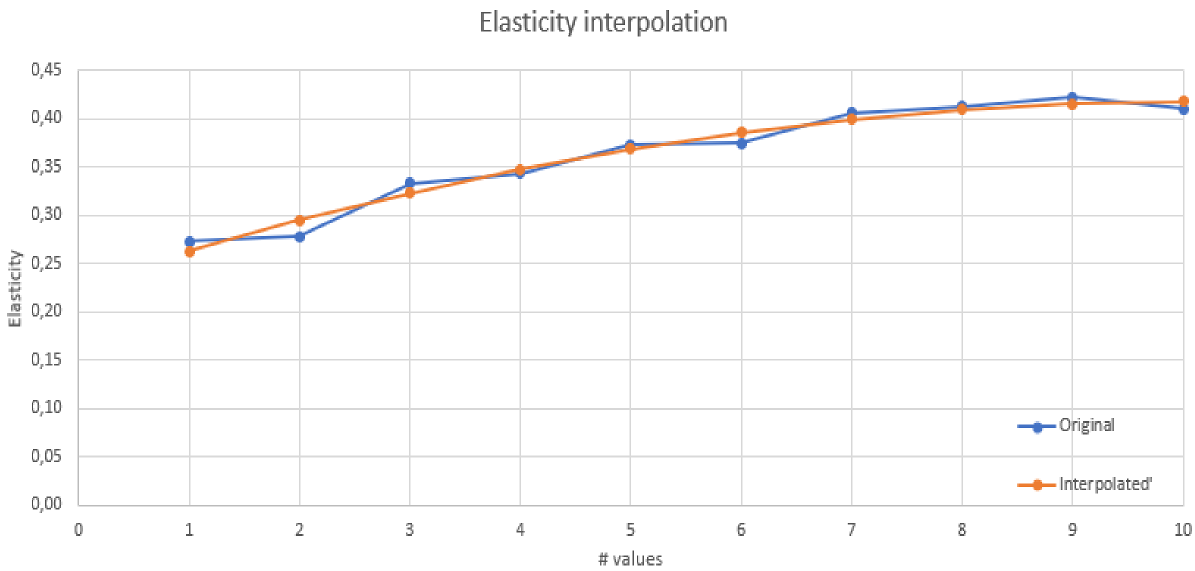

Figure 5-7: Elasticity values interpolation

Table 5-6: Qfin values in [MW] with real and interpolated elasticity

Real Q_{fin}	**Computed Q_{fin}**	**Difference: Real-Computed**
5565.2329	5577.4033	12.1704
5565.2329	5543.7511	-21.4818
5565.2329	5577.4248	12.1919
5565.2329	5559.3648	-5.8681
5565.2329	5570.6899	5.4571
5565.2329	5550.4154	-14.8175
5565.2329	5574.0748	8.8419
5565.2329	5569.8387	4.6058
5565.2329	5574.7247	9.4918
5565.2329	5554.8849	-10.3479
Total [MW]	**Total [MW]**	**Total [MW]**
55652.3291	55652.5726	0.2435

Another way to demonstrate the accuracy of the method is given by the measurement of its MAPE (Mean Absolute Percentage Error), expressed by equation 5.4. According to [45], measures under 10 of MAPE are to be considered of highly accurate forecasting. In this case

MAPE=2.3846 meaning that this method is reliable.

$$MAPE = \frac{100\%}{n} * \sum_{i=1}^{n} \left| \frac{Ai - Fi}{Ai} \right| \tag{5.4}$$

In equation 5.4, n stands for the number of elements, A_i stands for the "Actual i-th value" and F_i the interpolated one. Once new Q_{fin} are defined, let's see how they impact on remuneration.

First of all, it's important to obtain a relation between ΔP and ΔQ. Working on data from Portuguese grid, some graphs have been plotted. All of them showed that points follow an almost-linear behaviour.

In the following chapter it is discussed how these graphs can be interpolated with a linear regression, a quadratic, a cubic or logarithmic interpolation. Since it will be demonstrated that all of them (except the logarithmic one) present MAPE<10, for now only the linear one will be used for some ΔP considerations.

At this point, interpolated Q_{fin} (and their differences from real Q_{fin} values) have been obtained. It assumes importance to study the economic impact of new Q_{fin} values: for that purpose, plots as the one represented in Fig.5.8 will be used. Thanks to interpolation equation it's possible to compute ΔP for each ΔQ given as input. The MAT user has been chosen as default user, since DR programs will involve very likely high voltage levels in the first steps. Any other possible voltage user could have been studied: author's choice doesn't compromise studies of other consumer types.

Plot 5.8 shows original values of ΔP over ΔQ (blue points). Interpolated points (orange) are instead found thanks to Microsoft Excel tools, as well as the interpolation line equation (see equation 5.5).

$$y = -1.447*10^{-04}\,x + 6.425*10^{-06} \tag{5.5}$$

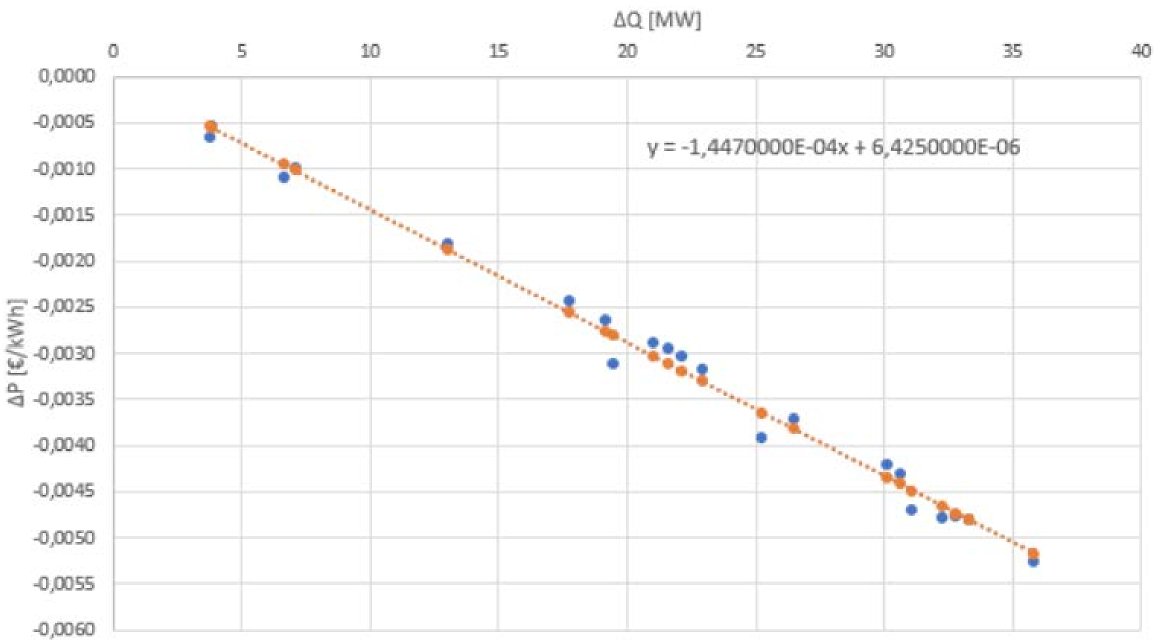

Figure 5-8: Plot of ΔP over ΔQ (MAT user)

Right column values of Table 5.6 have been used as input in equation 5.5 and the remuneration values showed in Tab.5.7 have been obtained.

Table 5-7: ΔP values from computed ΔQ

ΔQ [MW]	ΔP [€/kWh]
12.1704	-0.00175462316
-21.482	0.00311483762
12.1919	-0.00175774186
-5.8681	0.00085554625
5.45714	-0.00078321440
-14.818	0.00215051835
8.84193	-0.00127299928
4.60581	-0.00066003365
9.49182	-0.00136704222
-10.348	0.00150376823
Total [MW]	**Total [€/kWh]**
0.2435	-0.00002880913

From Table 5.7 it can be seen that a gap of ΔQ from the actual values impacts on ΔP for no more than ~0.003 [€/kWh] during DR. Economically speaking, in the worst case scenario from a DNO point of view (meaning that he has to pay more than expected due to more available power), the amount of money that would have been wasted would be ~50€. In order to compute that, the following hypothesis was made: all ΔQ have been taken with positive sign, as to say that all the production was exceeding and it had to be remunerated.

The following steps have been followed:

1. Take absolute values of ΔQ (left column of Table 5.8);

2. Apply to each ΔQ its ΔP[22] (right column in Table 5.8)

3. Multiply all results by 0.25 because each measure is relative to 15 minutes[23];

4. Sum all the results in order to get overall money.

Table 5-8: Values used to compute worst case scenario

$\lvert\Delta Q\rvert$	ΔP	$\lvert\Delta Q\rvert \cdot \Delta P \cdot 0.25 \cdot 1000$
12.170	0.00175462316	5.3386
21.482	0.00311483762	16.728
12.192	0.00175774186	5.3576
5.8681	0.00085554625	1.2551
5.4571	0.00078321440	1.0685
14.818	0.00215051835	7.9663
8.8419	0.00127299928	2.8139
4.6058	0.00066003365	0.7599
9.4918	0.00136704222	3.2439
10.348	0.00150376823	3.8902
Total [MW]	**Total [€/kWh]**	**Total [€]**
105.27	0.01522032502	48.422243

An error of ~48.5€ represents more or less 0,0231% of the money volume that has been shifted from T1 tariff to T2. It can be considered an acceptable amount compared to benefits brought by DR.

Elasticity interpolation can be used by DNO in order to compute how much power will be available the day after thanks to DR programs. In the past, where every user type was classified by a specific constant elasticity value, available power was calculated by mean of the already presented (5.6):

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \tag{5.6}$$

[22] Since ΔP is expressed in [€/kWh] and power in [MW], a multiplication of ΔQ by a factor 1000 is needed to convert MW into kW.

[23] 25 is indeed the decimal expression of 15 minutes.

that gave a unique value supposed to work the entire day/week/year. For instance, let's consider e = -0.38 (as indicated for Industrial consumers in Tab.3.1): given the initial power (Q_{in}) and ΔP = 0.0488 [€/kWh], Q_{fin} is then calculated. In order to better compare Q_{fin} with different elasticity values, in Tab.5.9 all Q_{fin} are reported for each case. An average value of Q_{fin} for "literature elasticity" case and "interpolated" one was computed: successively, a comparison between them and the "real elasticity" case was done to see how much power is being wasted due to a non-accurate elasticity definition. Looking at Tab.5.9, the average value of Q_{fin} of the upper table is Q_{fin}=6537.907699 [MW]; the one of the middle table is 6516.18476 [MW] while the last one is 6516.16041 [MW]. The difference between the first 2 values is -21.7229 [MW], whilst the difference between 2nd and 3rd table is 0.02435 [MW]. That shows how an elasticity interpolation brings an average error, in terms of excess unexpected power, of only 24 [kW] while the fixed value gives a lack of almost 22 [MW].

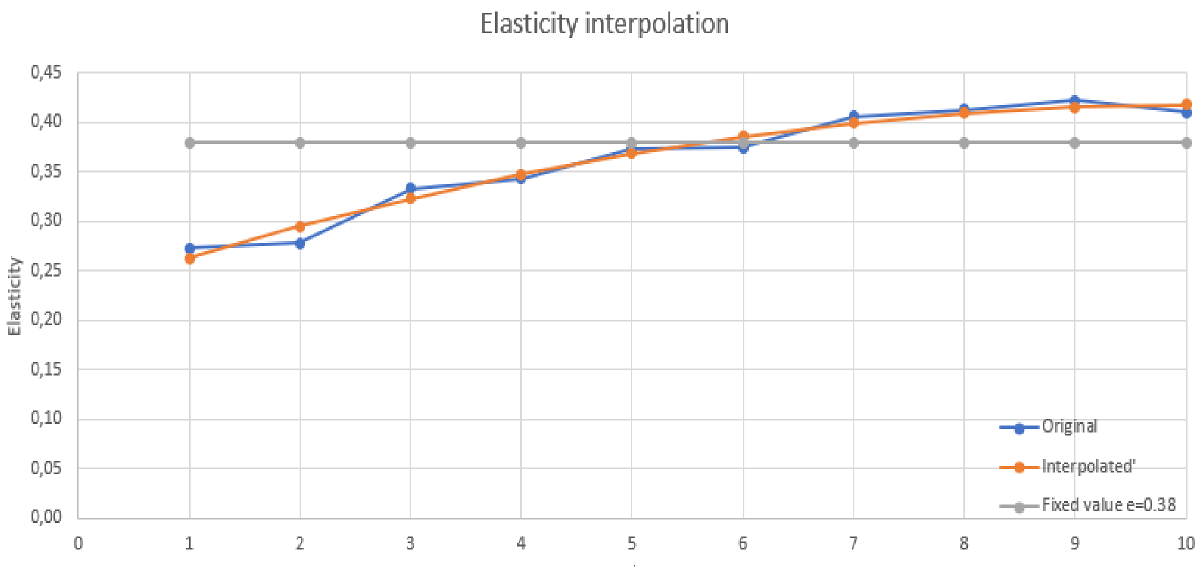

Figure 5-9: Plot of trend of 3 elasticities cases: fixed, real, interpolated one

In plot 5.9 a comparison of trends of 3 elasticities values is represented: the fixed value e=0.38, the real value (extrapolated from real data) and the interpolated one.

Table 5-9: Effects of different elasticities on Qfin given ∆P=0.0488 [€/kWh]

Literature Elasticity	Q in [MW]	Q fin [MW]
0.38	5914.51146	6401.323265
0.38	5922.38693	6409.846952
0.38	5997.65854	6491.314022
0.38	6012.70323	6507.597008
0.38	6054.60039	6552.942642
0.38	6057.08581	6555.632636
0.38	6102.36342	6604.636952
0.38	6111.90505	6614.963933
0.38	6126.11484	6630.343307
0.38	6107.75867	6610.476271

Real Elasticity	Q in [MW]	Q fin [MW]
0.272643036	5914.511457	6263.790008
0.278419814	5922.386929	6279.540953
0.332867248	5997.658541	6430.084176
0.343586299	6012.703228	6460.173550
0.373156486	6054.600389	6543.967873
0.374897794	6057.085812	6548.938720
0.406371391	6102.363418	6639.493931
0.412944526	6111.905046	6658.577187
0.422695562	6126.114842	6686.996775
0.410090648	6107.758665	6650.284425

Interpolated Elasticity	Q in [MW]	Q fin [MW]
0.263143001	5914.511457	6251.619668
0.295165955	5922.386929	6301.022727
0.323482324	5997.658541	6417.892283
0.348092108	6012.703228	6466.041699
0.368995309	6054.600389	6538.510793
0.386191925	6057.085812	6563.756227
0.399681958	6102.363418	6630.652022
0.409465406	6111.905046	6653.971391
0.415542269	6126.114840	6677.504949
0.417912549	6107.758665	6660.632339

Section 3: Change of elasticity value during weekends

Being elasticity strictly correlated to ΔP and ΔQ, it can be defined only if a consumer is participating DR program. Data used until now suggest that on Sunday it is not necessary for the consumer to cut his power, since only a small amount of it is requested by the entire grid (comparing to the weekdays) and no congestions occur. That's why elasticity is usually not defined for this particular day. In fact double/triple tariffs contracts present only one tariff on Sundays and moving loads into different periods would result only in a useless loss of comfort for the consumer.

As already mentioned, other reasons influence elasticity value, as the weather, user's particular habits and routines or even unexpected events (fault in the domestic electric system for example). Previously in this work it was showed also that these reasons are responsible for different values of elasticity even along the same day when participating DR programs.

Now then, a comparison between elasticity during a Monday and a Saturday day will be done. Only daily average values will be considered, since the goal of this section is to demonstrate the difference between a given elasticity value for a weekday and for a weekend day.

Second and third tables of Tab.5.9 are considered, whose average values are 0.3627672804 and 0.3627672803 respectively. Therefore 0.363 (their average) will be used for this section. In order to compare elasticity in 2 different days, the same DR program has to be applied. Therefore even for Saturday it will be imposed a power cap of 15% of the average power: if there will be exceeding power during the highest tariff, it will be paid at the cheapest one[24].

Calculations brought user to participate to DR from 18:45 to 22:00, where there was high consumption during the most expensive tariff. The average value of elasticity (in absolute terms) found out for that period is 0.185, almost half of the value during the week.

As a conclusion, it can be stated that during the week a consumer is more willing to participate DR due to highest ΔP and then remunerations. A social aspect has to be considered too: during weekends people may need more electric energy for leisure activities or other types of needs.

[24] It may be helpful to remember that on Saturday only 2 tariffs are scheduled: "*Vazio*"- 0.1016 [€/kWh] and "*Cheias*"- 0.1765 [€/kWh]

Table 5-10: Tariffs along the 24h: colours help to understand their trend

Hour	Tariff	Value		Hour	Tariff	Value		Hour	Tariff	Value
00:15	T3	0.1016		08:15	T2	0.1765		16:15	T2	0.1765
00:30	T3	0.1016		08:30	T2	0.1765		16:30	T2	0.1765
00:45	T3	0.1016		08:45	T2	0.1765		16:45	T2	0.1765
01:00	T3	0.1016		09:00	T2	0.1765		17:00	T2	0.1765
01:15	T3	0.1016		09:15	T2	0.1765		17:15	T2	0.1765
01:30	T3	0.1016		09:30	T2	0.1765		17:30	T2	0.1765
01:45	T3	0.1016		09:45	T1	0.2253		17:45	T2	0.1765
02:00	T3	0.1016		10:00	T1	0.2253		18:00	T2	0.1765
02:15	T3	0.1016		10:15	T1	0.2253		18:15	T2	0.1765
02:30	T3	0.1016		10:30	T1	0.2253		18:30	T2	0.1765
02:45	T3	0.1016		10:45	T1	0.2253		18:45	T1	0.2253
03:00	T3	0.1016		11:00	T1	0.2253		19:00	T1	0.2253
03:15	T3	0.1016		11:15	T1	0.2253		19:15	T1	0.2253
03:30	T3	0.1016		11:30	T1	0.2253		19:30	T1	0.2253
03:45	T3	0.1016		11:45	T1	0.2253		19:45	T1	0.2253
04:00	T3	0.1016		12:00	T1	0.2253		20:00	T1	0.2253
04:15	T3	0.1016		12:15	T2	0.1765		20:15	T1	0.2253
04:30	T3	0.1016		12:30	T2	0.1765		20:30	T1	0.2253
04:45	T3	0.1016		12:45	T2	0.1765		20:45	T1	0.2253
05:00	T3	0.1016		13:00	T2	0.1765		21:00	T1	0.2253
05:15	T3	0.1016		13:15	T2	0.1765		21:15	T2	0.1765
05:30	T3	0.1016		13:30	T2	0.1765		21:30	T2	0.1765
05:45	T3	0.1016		13:45	T2	0.1765		21:45	T2	0.1765
06:00	T3	0.1016		14:00	T2	0.1765		22:00	T2	0.1765
06:15	T3	0.1016		14:15	T2	0.1765		22:15	T2	0.1765
06:30	T3	0.1016		14:30	T2	0.1765		22:30	T2	0.1765
06:45	T3	0.1016		14:45	T2	0.1765		22:45	T2	0.1765
07:00	T3	0.1016		15:00	T2	0.1765		23:00	T2	0.1765
07:15	T2	0.1765		15:15	T2	0.1765		23:15	T2	0.1765
07:30	T2	0.1765		15:30	T2	0.1765		23:30	T2	0.1765
07:45	T2	0.1765		15:45	T2	0.1765		23:45	T2	0.1765
08:00	T2	0.1765		16:00	T2	0.1765		24:00	T2	0.1765

5.2 SIMULATION OF A CONTRACT CHANGE

In this chapter it will be analyzed a possible double/triple-tariffs contract that an end-user could sign abandoning his mono tariff one. Tariffs' values and schedules are taken from "EDP[25]" and Portuguese Regulator of energetic systems "ERSE"[26] respectively.

Table 5-11: Mono-tariff, bi-tariff, three tariff contracts

Monotariff [€/kWh]	Bi-tariff [e/kWh]	Three-tariff [€/kWh]
0.1544 *"Vazio"*	0.187 *"Fora Vazio"*	0.2735 *"Ponta"*
	0.110 *"Vazio"*	0.1571 *"Cheias"*
		0.1038 *"Vazio"*

Table 5-12: Schedule for a three-tariff contract (Summertime)

Monday-Friday	Saturday	Sunday
"Vazio"	*"Vazio"*	*"Vazio"*
00.00-07.00h	00.00-09.30h / 13.00-18.30h / 22.00-24.00h	*All day for 24h*
"Cheias"	*"Cheias"*	
07.00-09.30h / 12.00-18.30h / 21.00-24.00h	09.30-13.00h / 18.30-22.00h	
"Ponta"		
09.30-12.00h / 18.30-21.00h		

Table 5-13: Schedule for a double tariff contract (Summer schedule)

Monday-Friday	Saturday	Sunday
"Vazio"	*"Vazio"*	*"Vazio"*
00.00-07.00h	00.00-09.30h / 13.00-18.30h / 22.00-24.00h	*All day for 24h*
"Fora de vazio"	*"Fora de vazio"*	
07.00-24.00h	09.30-13.00h / 18.30-22.00h	

It's not necessary to show the schedule of the 1T contract since the same price is applied all over the 24h for each day of the week: there are not distinctions between peak and valley hours then. That's why an obsolete mono-tariff contract type that doesn't allow end-users to drive consumptions into more economic periods is not advantageous for the user and, at the same

[25]Portuguese Energy Producer: https://www.edp.pt/particulares/energia/tarifarios/

[26](Entitade Reguladora Dos Servicos Energeticos) http://www.erse.pt/pt/electricidade/tarifaseprecos/periodoshorarios/Paginas/CiclodiariofornecBTEBTNPt.aspx

time, represents a serious challenge for the DNO to manage peak-power consumptions.

Now the used method will be explained (Fig.5.11 sums the algorithm adopted).

EDP				
kVA	20,7	17,25	6,9	Period
From	Simples	Simples	Simples	
	0,158	0,1571	0,1544	Normal
To	Bi-horario	Bi-horario	Bi-horario	
	0,188	0,1877	0,187	Fora vazio
	0,1108	0,1107	0,11	Vazio
To	Tri-horario	Tri-horario	Tri-horario	
	0,273	0,2727	0,2735	Ponta
	0,1568	0,1566	0,1571	Cheias
	0,1036	0,1035	0,1038	Vazio

Figure 5-10: EDP tariffs for 3 users depending on the signed contract

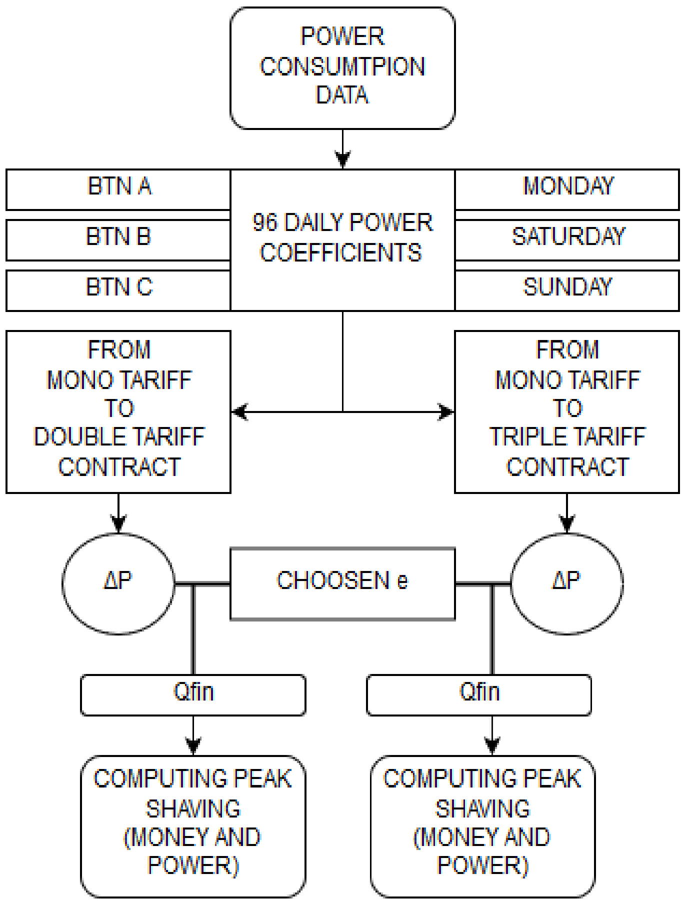

Figure 5-11: Scheme to evaluate Qfin and costs of the peak shaving

First step: Users classification

The data the author used are relative to power absorption of the Portuguese grid all over the 365 days of the year, divided in 96 values per each day (one every 15 minutes along the 24h). Moreover, since EDP differentiates users according to their contracted power, 3 cases have been explored: 20.7 [kVA], 17.25 [kVA] and 6.9 [kVA] that have been classified as BTN-A, BTN-B and BTN-C user type respectively.

In order to determine the exact amount of power absorbed by each consumer, 96 coefficients are given: they are supposed to be applied to every power measurement (i.e. every 15 minutes) all over the all year. Since the overall power is a few Gigawatt as order of magnitude, these coefficients range between 0.02 to 0.05, more or less. They change every 15 minutes and from user to user because their role is to adapt the overall consumption curve to its specific consumer. Tab. 5.14 shows the amount of money that every operator has to pay every 15 minutes: it is given by the tariff (of the mono-tariff contract type in this case) multiplied by the absorbed power and by 0.25 (it represents 15 minutes in the decimal unit system as it will be better explained later).

The same procedure will be adopted for the double-tariff case and the triple one, since only the input values change.

Second step: Days distinction

Three days have been considered and each one has been analyzed by every user's point of view. The selected days are Monday, Saturday and Sunday of the first week of July. Monday has been chosen as a representation of a typical weekday in which triple tariff schedule can be applied; Saturday and Sunday were instead mandatory since they have their own tariffs schedule.

Third step: Tariffs definition

The "triple tariff" schedule has been already presented in Tab.5.12 (pag.51): it can be noticed that from Monday to Friday 3 different prices along the 24h are scheduled, whilst on Saturday and Sunday only 2 and 1 prices, respectively. Their values are shown in Fig. 5.10 (pag.52), where contracted powers are written in place of BTN-A, BTN-B, BTN-C.

Table 5-14: Night mono-tariff table with imports for each user every 15 minutes

Tariffs				BTN A, BTE e MT, (EDP: 20.7); Mono→Bi/Tri	BTN B (EDP: 17.25); Mono→Bi/Tri	BTN C (EDP:6.9); Mono→Bi/Tri
BTN A	*BTN B*	*BTN C*	*Time*			
0,158	0,1571	0,1544	00:15	4,550682329	6,235666203	7,692676189
0,158	0,1571	0,1544	00:30	4,433096083	6,054316433	7,476990269
0,158	0,1571	0,1544	00:45	4,32947389	5,887197632	7,227257769
0,158	0,1571	0,1544	01:00	4,242443719	5,73517598	6,958406633
0,158	0,1571	0,1544	01:15	4,101840242	5,507534142	6,598751141
0,158	0,1571	0,1544	01:30	3,996959487	5,347412699	6,316488282
0,158	0,1571	0,1544	01:45	3,840895838	5,134643682	5,957565356
0,158	0,1571	0,1544	02:00	3,740128829	4,985024155	5,682105368
0,158	0,1571	0,1544	02:15	3,555390518	4,725078932	5,299602529
0,158	0,1571	0,1544	02:30	3,464337974	4,598760521	5,065906862
0,158	0,1571	0,1544	02:45	3,297573517	4,380601339	4,738930924
0,158	0,1571	0,1544	03:00	3,23166426	4,260196792	4,535549621
0,158	0,1571	0,1544	03:15	3,123564621	4,055304652	4,271374723
0,158	0,1571	0,1544	03:30	3,092970308	3,9418605	4,117400843
0,158	0,1571	0,1544	03:45	3,004747794	3,784327793	3,92522419
0,158	0,1571	0,1544	04:00	2,970360343	3,709883933	3,825780191
0,158	0,1571	0,1544	04:15	2,895930441	3,603948482	3,682969448
0,158	0,1571	0,1544	04:30	2,872010705	3,566250918	3,599155078
0,158	0,1571	0,1544	04:45	2,826537308	3,50862912	3,491434878
0,158	0,1571	0,1544	05:00	2,816096985	3,480584889	3,419629786
0,158	0,1571	0,1544	05:15	2,78923735	3,420817408	3,334184601
0,158	0,1571	0,1544	05:30	2,786246657	3,38631022	3,287535004
0,158	0,1571	0,1544	05:45	2,766230518	3,332192961	3,230940826
0,158	0,1571	0,1544	06:00	2,767834685	3,293871653	3,198018903
0,158	0,1571	0,1544	06:15	2,770404882	3,265840691	3,190395463
0,158	0,1571	0,1544	06:30	2,782884287	3,252321316	3,198790062

Fourth step: Tariffs application

Prices have been applied over the 3 different days for all consumers. Study took into consideration one day at a time, therefore the mono-double-triple tariffs have been applied to the three users on Monday, Saturday and Sunday. Tables 5.16, 5.17 and 5.18 represent this step.

Fifth step: Definition of Qfin for each case

Since the goal of the study is to determine whether a new contract allows to save money managing consumptions over the day, it's mandatory to evaluate Q_{fin}. As previously written, and here reported, Q_{fin} is given by the equation 5.7.

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \quad (5.7)$$

Its evaluation, computed for each user every 15 minutes, is necessary to determine how elasticity affects consumptions during the day. In fact, three scenarios have been considered:

- Participate to DR program over the hole day (moving energy from “peaks” to “valleys”);
- Participate to DR program only in peak hours (only reducing loads during “peaks”);
- Switching to a 2T/3T contract without participating DR (just to make a comparison);

Elasticity was selected to be a parameter in order to see the effects of its variation. ΔP is given by P_{fin}-P_{in}, where P_{fin} is the tariff of the double/triple contract in that specific 15 minutes and P_{in} the tariff of the single tariff contract. Initial power Q_{in} is the power before participate DR program.

Sixth step: Comparison with mono-tariff case

In order to check how much elasticity worked[27], a comparison with situation before DR has to be done. That allows to check how much power has been moved from peak hours to valley hours, calculating the total cost of the operation.

Seventh step: Evaluating of the expenses for each case

Costs of the hole day are then computed, simply applying the tariff to the corresponding power value. Expenses are compared considering every one of the three scenarios presented above.

Finally, conclusions are made.

[27] Since $e<0$, during positive ΔP a power cut will occur (i.e. in the peak hours), while during negative ΔP periods an increment of production is expected to happen (”valley hours”).

APPLICATION ON MONDAY

Here it will be presented a study case that consider Monday as example day since all three tariffs of a triple-tariff contract can be applied during it.

Firstly, the mono-tariff contract has been applied in order to be able to compare whether a mono-tariff contract is more convenient than a double/triple tariff one. The three users classification has been adopted for every day in every contract, as previously mentioned. In table 5.19, 3 tariffs are reported (one per consumer: each one remains constant along the 24h since it's a mono-tariff contract). Expenses are shown too, evaluated multiplying the tariff by the corresponding power consumption (3 columns on the right).

It might be helpful to remind that tariff is expressed as [€/kWh] while power consumption as [MW], therefore a conversion into energy units is required: that is satisfied by using a 0.25 factor (since it expresses 15 minutes into decimal units) into the "tariff x power" multiplication.

Here are now reported the overall prices related to consumes calculated with mono, double and triple tariff contract. In these last 2 cases, DR is not applied yet therefore consumptions are not moved from high tariff periods to low tariffs. Tables 5.16, 5.17 and 5.18 report money values.

Table 5-16: Total money paid over the day - mono tariff

BTN-A user	BTN-B user	BTN-C user
423,602.2915 €	547,889.727 €	675,578.651 €

Table 5-17:Total money paid over the day - double tariff (no DR)

BTN-A user	BTN-B user	BTN-C user
458,749.5776 €	596,285.1746 €	753,520.1255 €

Table 5-18: Total money paid over the day - triple tariff (no DR)

BTN-A user	BTN-B user	BTN-C user
468,236.5816 €	608,195.1568 €	782,638.5917 €

Firstly, the double tariff contract ("2T") will be presented. In table 5.19 the two tariffs along the day are separated by different colors (blue for *"Vazio"* and pink for *"Fora de Vazio"* periods). Please note that 2 different tariffs are present for each kind of consumer but they're not the same (as can be seen in the grey stripe of Fig.5.10, in page 52). The overall expense is reported in Table 5.17: values are bigger than 1T case since DR program is not applied yet.

The same consideration can be done about Tab.5.20, where a triple tariff contract ("3T") schedule is shown. The three tariffs periods are distinguishable thanks to the colors: blue for "Vazio" (not reported in this template), pink for "Cheias", orange for "Ponta". Even now tariffs schedule over the 24h is common to all users while the amounts are different. Moreover, total expense is reported in Tab.5.18 and again values are bigger than 1T case since DR program is not applied yet.

Table 5-19: First 8 hours of double tariff schedule for each user every 15 minutes (afternoon and night hours have been not reported since they are constant from 07:15 on)

Tariffs				BTN A, BTE e MT, (EDP: 20.7); Mono→Bi/Tri	BTN B (EDP: 17.25); Mono→Bi/Tri	BTN C (EDP:6.9); Mono→Bi/Tri
BTN A	*BTN B*	*BTN C*	*Time*			
0,1108	0,1107	0,11	00:15	3,191237988	4,393941748	5,480533554
0,1108	0,1107	0,11	00:30	3,108778772	4,266154227	5,326871305
0,1108	0,1107	0,11	00:45	3,036112069	4,148394512	5,148953074
0,1108	0,1107	0,11	01:00	2,975080785	4,041272954	4,957414052
0,1108	0,1107	0,11	01:15	2,876480372	3,880865879	4,701182808
0,1108	0,1107	0,11	01:30	2,802931083	3,768036828	4,500088802
0,1108	0,1107	0,11	01:45	2,69348898	3,618109838	4,244379463
0,1108	0,1107	0,11	02:00	2,62282452	3,512680929	4,048132063
0,1108	0,1107	0,11	02:15	2,493273857	3,32951138	3,775623564
0,1108	0,1107	0,11	02:30	2,42942182	3,240501526	3,609130536
0,1108	0,1107	0,11	02:45	2,312475606	3,086776373	3,376181358
0,1108	0,1107	0,11	03:00	2,266255696	3,001933704	3,231285352
0,1108	0,1107	0,11	03:15	2,190449114	2,857557129	3,043077847
0,1108	0,1107	0,11	03:30	2,168994368	2,77761908	2,93338143
0,1108	0,1107	0,11	03:45	2,107126934	2,666614174	2,796468011
0,1108	0,1107	0,11	04:00	2,08301219	2,614157552	2,725620602
0,1108	0,1107	0,11	04:15	2,030817043	2,539510483	2,623877197
0,1108	0,1107	0,11	04:30	2,01404295	2,512947019	2,564164887
0,1108	0,1107	0,11	04:45	1,982154011	2,472344008	2,487421221
0,1108	0,1107	0,11	05:00	1,974832569	2,452582732	2,436264744
0,1108	0,1107	0,11	05:15	1,955996825	2,410467773	2,375390584
0,1108	0,1107	0,11	05:30	1,953899555	2,386152396	2,342155767
0,1108	0,1107	0,11	05:45	1,93986292	2,348018847	2,301836081
0,1108	0,1107	0,11	06:00	1,940987868	2,321015862	2,278381343
0,1108	0,1107	0,11	06:15	1,942790259	2,301263937	2,272950136
0,1108	0,1107	0,11	06:30	1,95154164	2,291737554	2,278930743
0,1108	0,1107	0,11	06:45	1,961312894	2,292034498	2,280405605
0,1108	0,1107	0,11	07:00	1,986239356	2,316188945	2,288657691
0,1880	0,1877	0,1870	07:15	3,432597055	4,011236271	3,937424258
0,1880	0,1877	0,1870	07:30	3,464898701	4,075485202	3,992166851
0,1880	0,1877	0,1870	07:45	3,467396707	4,085809603	4,00665853

Table 5-20: Last 8 hours of triple tariff schedule every 15 minutes (morning and afternoon hours have been not reported)

0,1568	0,1566	0,1571	16:15	4,362483945	5,626276456	6,705629957
0,1568	0,1566	0,1571	16:30	4,341803198	5,644573738	6,756832199
0,1568	0,1566	0,1571	16:45	4,371466383	5,720406791	6,870534048
0,1568	0,1566	0,1571	17:00	4,417703611	5,778767883	7,040620852
0,1568	0,1566	0,1571	17:15	4,609771818	6,016743704	7,482203103
0,1568	0,1566	0,1571	17:30	4,783833169	6,206085873	7,933238153
0,1568	0,1566	0,1571	17:45	5,297289028	6,827531172	8,961076558
0,1568	0,1566	0,1571	18:00	5,522472514	7,126649408	9,572906538
0,1568	0,1566	0,1571	18:15	5,913279062	7,698095318	10,48597278
0,1568	0,1566	0,1571	18:30	5,999797557	7,882446559	10,86833403
0,2730	0,2727	0,2735	18:45	10,70102791	14,09173177	19,62086608
0,2730	0,2727	0,2735	19:00	10,77559293	14,20956243	20,02838438
0,2730	0,2727	0,2735	19:15	10,95432626	14,49764985	20,635643
0,2730	0,2727	0,2735	19:30	10,99895737	14,65331379	20,97540879
0,2730	0,2727	0,2735	19:45	11,07774422	14,80969992	21,28589737
0,2730	0,2727	0,2735	20:00	11,01978649	14,82553195	21,52176036
0,2730	0,2727	0,2735	20:15	11,03733797	14,9530491	21,87682631
0,2730	0,2727	0,2735	20:30	10,99850087	14,98477215	21,97335926
0,2730	0,2727	0,2735	20:45	10,98693175	15,04428634	21,86046985
0,2730	0,2727	0,2735	21:00	10,87683542	14,96327888	21,63155751
0,1568	0,1566	0,1571	21:15	6,151868687	8,539729136	12,2523921
0,1568	0,1566	0,1571	21:30	6,069616299	8,467742877	12,0993213
0,1568	0,1566	0,1571	21:45	5,944925616	8,332814079	11,82172877
0,1568	0,1566	0,1571	22:00	5,828318136	8,240139224	11,60595421
0,1568	0,1566	0,1571	22:15	5,676376724	8,111080829	11,31133277
0,1568	0,1566	0,1571	22:30	5,563198267	8,019365578	11,06646984
0,1568	0,1566	0,1571	22:45	5,394358232	7,776821045	10,63181335
0,1568	0,1566	0,1571	23:00	5,247348912	7,59173378	10,19801096
0,1568	0,1566	0,1571	23:15	4,969785508	7,233268546	9,492203052
0,1568	0,1566	0,1571	23:30	4,784820344	7,003947219	8,97203758
0,1568	0,1566	0,1571	23:45	4,52524525	6,582529757	8,24814406
0,1568	0,1566	0,1571	24:00	4,427856155	6,349581783	7,786002688

Trends of expenses along the 24h are displayed in graphs 5.12 and 5.13. They only show values relative to the BTN-A user type; since trends are equal to the other consumers', only graphs related to this user will be considered. Both graphs present two y-axes: on the left y-axis the overall money are meant to be read while on the right one the 3 different tariffs over the 24h

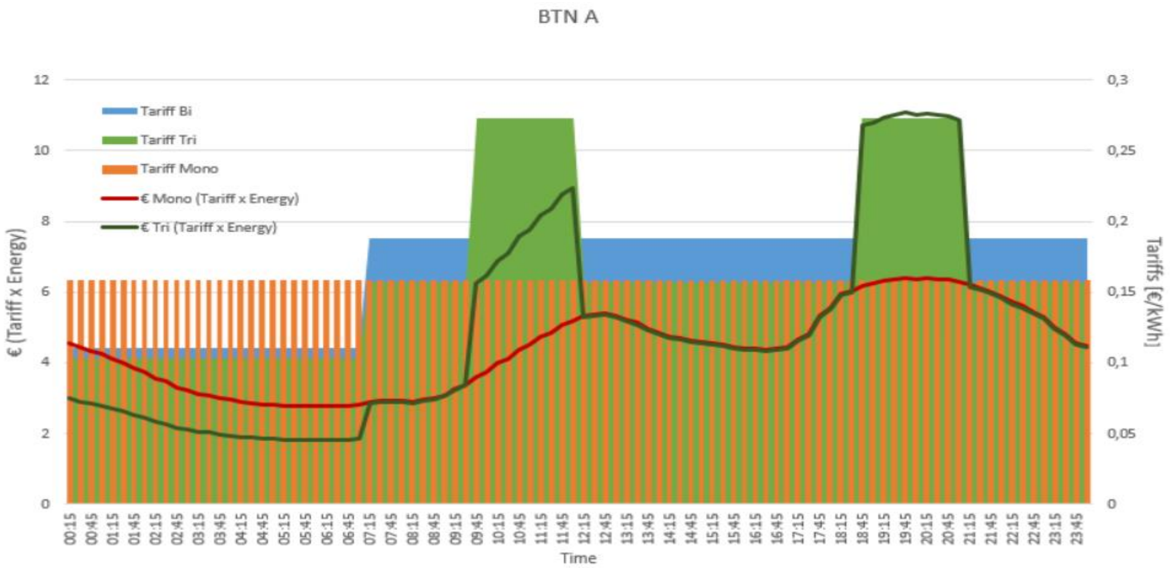

Figure 5-12: Monday expense trend of mono and bi tariff contracts

(0.2730 €/kWh, 0.1658 €/kWh and 0.1036 €/kWh). In order to avoid confusion, "areas" were chosen for tariffs while "lines" for trends. Therefore orange, blue and green areas represent mono, double and triple tariffs respectively while red, blue and green curves represent expense for mono, double and triple tariff contracts.

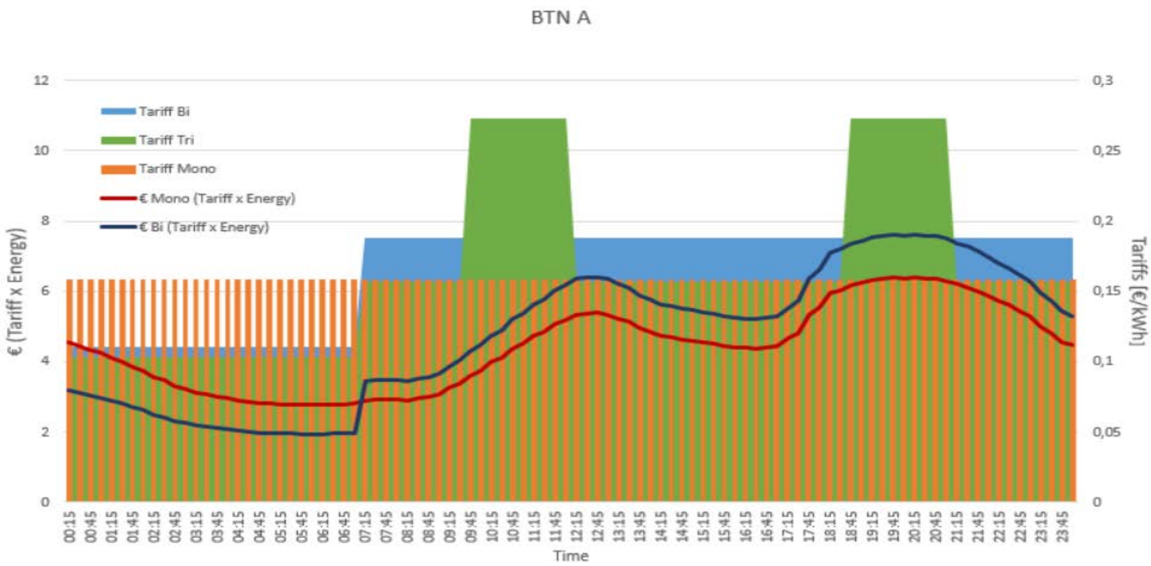

Figure 5-13: Monday expense trend of mono and tri-tariff contracts

In Tab.5.23 Q_{fin} evaluations are reported. All the "ΔP" are calculated, considering a switching from a mono to a double tariff contract and from a mono to a triple tariff contract, for every user (Tab.5.22 shows ΔP values for both cases differentiating hours of the day). These values have been inserted into the equation 5.7 to evaluate every Q_{fin}, reported in Tab.5.23, where the grey back-ground is used to distinguish "peak hours" from other periods according to the 3T contract (triple-tariff).

Table 5-22: Evolution of ΔP [€/kWh] over the 24h for every consumer.

ΔP: From a Mono-tariff to a Bi-tariff contract						
User	**00:00-07:00**	**07:15-09:30**	**09:45-12:00**	**12:15-18:30**	**18:45-21:00**	**21:15-24:00**
BTN-A	-0.0472	0.03	0.03	0.03	0.03	0.03
BTN-B	-0.0464	0.0306	0.0306	0.0306	0.0306	0.0306
BTN-C	-0.0444	0.0326	0.0326	0.0326	0.0326	0.0326

ΔP: From a Mono-tariff to a Tri-tariff contract						
User	**00:00-07:00**	**07:15-09:30**	**09:45-12:00**	**12:15-18:30**	**18:45-21:00**	**21:15-24:00**
BTN-A	-0.0544	-0.0012	0.115	-0.0012	0.115	-0.0012
BTN-B	-0.0536	-0.0005	0.1156	-0.0005	0.1156	-0.005
BTN-C	-0.0506	0.0027	0.1191	0.0027	0.1191	0.0027

Table 5-23: Qfin evaluation every 15 minutes for every consumer (afternoon hours are not reported)

	e=-0,35	*OUTPUT POWER Qfin*					
		BTN A		BTN B		BTN C	
Time	*-0,35*	*Mono → Bi*	*Mono → Tri*	*Mono → Bi*	*Mono → Tri*	*Mono → Bi*	*Mono → Tri*
00:15		127,2528569	129,090338	175,1819163	177,7286939	219,3504174	222,1513495
00:30		123,9647378	125,7547397	170,0871599	172,5598704	213,2003084	215,9227085
00:45		121,0671019	122,8152632	165,3922018	167,7966574	206,0793889	208,7108605
01:00		118,6334366	120,3464567	161,1213759	163,4637428	198,413317	200,9468988
01:15		114,7016759	116,3579228	154,7261116	156,9755047	188,1580326	190,5606625
01:30		111,7688463	113,3827444	150,227734	152,4117301	180,1095363	182,4093932
01:45		107,4047655	108,955648	144,2502999	146,3473966	169,8751404	172,0443122
02:00		104,5869706	106,0971652	140,0469582	142,0829472	162,0206224	164,0894982
02:15		99,42104681	100,8566475	132,7441776	134,6739995	151,1138644	153,0434695
02:30		96,87490198	98,27373738	129,1954467	131,0736775	144,4502222	146,2947378
02:45		92,21158952	93,54308852	123,0665838	124,8557137	135,1267687	136,8522312
03:00		90,36853816	91,67342423	119,6839942	121,4239484	129,3275159	130,9789265
03:15		87,34569742	88,60693486	113,9278494	115,5841213	121,7947832	123,3500066
03:30		86,49017435	87,73905837	110,740802	112,3507409	117,404343	118,903504
03:45		84,02316696	85,23642836	106,3151511	107,8607504	111,9245817	113,3537705
04:00		83,06157459	84,26095098	104,2237598	105,7389546	109,0890167	110,4819976
04:15		80,98025646	82,14957944	101,2476583	102,7195869	105,0168843	106,3578673
04:30		80,3113777	81,47104233	100,1886005	101,6451326	102,6269856	103,9374514
04:45		79,03978383	80,18108715	98,56980037	100,0027985	99,55543154	100,826676
05:00		78,7478362	79,88492392	97,78193873	99,20348301	97,50796763	98,75306761
05:15		77,99674768	79,12298997	96,10285883	97,49999281	95,07156754	96,2855566
05:30		77,91311755	79,03815225	95,13342989	96,51647041	93,74139216	94,93839593
05:45		77,3533969	78,47034945	93,6130847	94,97402259	92,12765511	93,30405273
06:00		77,39825496	78,51585525	92,53650361	93,88179027	91,18891318	92,35332381
06:15		77,47012658	78,58876467	91,74901476	93,08285298	90,97153698	92,13317189
06:30		77,81909403	78,94277107	91,36920772	92,69752435	91,21090215	92,37559356
06:45		78,20872966	79,33803289	91,38104657	92,7095353	91,26993136	92,43537652
07:00		79,20268987	80,34634549	92,3440594	93,68654832	91,60020914	92,76987169
07:15		68,18045592	73,22812086	79,65429317	85,57708148	77,99898792	83,70749487
07:30		68,82205204	73,91721684	80,93013502	86,94779005	79,08341941	84,87129258
07:45		68,87166903	73,97050718	81,13515483	87,16805435	79,37049448	85,17937779
08:00		68,85451749	73,95208584	80,48540702	86,46999377	79,61917964	85,44626346
16:15		103,8921438	111,5836842	133,9135513	143,8708503	158,118163	169,6903469
16:30		103,3996338	111,0547117	134,3490532	144,3387345	159,3255074	170,9860531
16:45		104,1060597	111,8134372	136,15399	146,2778795	162,0065869	173,8633527
17:00		105,2071949	112,9960937	137,5430688	147,7702448	166,0172188	178,1675104
17:15		109,7812812	117,9088174	143,2072389	153,855581	176,4296893	189,3420377
17:30		113,9265358	122,3609614	147,7138576	158,6972945	187,065056	200,7557743
17:45		126,1544387	135,4941436	162,5051583	174,5884198	211,301395	226,7658967
18:00		131,5171622	141,2538904	169,6246067	182,2372431	225,7282919	242,248654
18:15		140,8241833	151,2499466	183,2258494	196,8498221	247,2583135	265,3543919
18:30		142,8846131	153,462918	187,6136767	201,5639114	256,274358	275,0302931
18:45		146,3719217	116,8494493	192,6080557	153,4654254	265,7536294	209,4861202
19:00		147,3918448	117,6636591	194,218584	154,7486552	271,2732362	213,8370713
19:15		149,8366137	119,6153306	198,1562092	157,8860595	279,4982138	220,32059
19:30		150,4470915	120,1026782	200,283849	159,5813112	284,1001509	223,9481678
19:45		151,5247622	120,9629881	202,4213598	161,284428	288,3055446	227,2631615
20:00		150,7319986	120,3301209	202,6377544	161,456846	291,5001766	229,7814001
20:15		150,9720731	120,5217736	204,3806794	162,8455663	296,3093458	233,5723331
20:30		150,4408475	120,0976935	204,8142751	163,1910448	297,6168304	234,6029865
20:45		150,2826015	119,9713649	205,6277247	163,8391817	296,0878066	233,3977
21:00		148,7766703	118,7691724	204,5205017	162,9569733	292,9873174	230,9536714
21:15		146,5061727	157,3525958	203,2579566	218,3714402	288,9103251	310,0547866
21:30		144,5473398	155,2487429	201,5445791	216,5306625	285,3009293	306,1812302
21:45		141,577843	152,0594026	198,3330778	213,0803662	278,7553217	299,1565697
22:00		138,8008468	149,0768146	196,1272816	210,7105555	273,6673768	293,6962536
22:15		135,1823765	145,1904548	193,0555044	207,4103726	266,7202291	286,2406654
22:30		132,4870422	142,2955744	190,8725482	205,0651002	260,9463829	280,0442492
22:45		128,4661326	137,9769812	185,099636	198,8629364	250,6972211	269,0449826
23:00		124,9651196	134,2167745	180,6942903	194,130026	240,4681991	258,0673299
23:15		118,3549733	127,1172533	172,1622971	184,9636264	223,8253108	240,2063996
23:30		113,9500453	122,3862114	166,7041164	179,0995963	211,5598549	227,0432725
23:45		107,7682889	115,7467955	156,6737687	168,3234304	194,4905095	208,724674
24:00		105,4489768	113,2557756	151,1292686	162,3666625	183,5932567	197,0298847

Tab.5.23 shows Q_{fin} values for the three users, considering for each one of them a contract evolution from mono to double tariff and from mono to triple tariffs. Grey background is used to detect “peak hours” according to the 3T contract: as explained earlier, this schedule has been applied also to the 2T contract since power peaks occurred in the same periods.

At this point two ways of participating DR are possible: the first one is to move the saved energy during peaks into valleys (i.e. participating DR keeping constant daily energy constant); the second one instead is to reduce load during peak hours without using that energy in the night.

DR applied over the 24h

Table 5.25 shows the difference of energy saved during peaks minus the energy used during valleys considering different elasticity values: negative values mean that night consumption (that correspond to valley energy time) overcompensates energy saved during the day. Being the tariffs very different in these two periods, it can be seen as a reasonable choice. Positive prices instead are a consequence of the fact that saved power in “peaks” is more than the used power in the nights. A consideration has to be done: 2T schedule doesn’t present the same “peaks-periods” as the 3T since it has only 2 tariffs (daily and nocturnal one). Despite that, peaks periods of 3T contract have been applied to the 2T because data showed an increment of consumption, therefore it was necessary to move energy from that specific interval into another.

Two important conclusions can be drawn:

- Participating DR in a 2T contract allows to compensate almost totally the consumption decrease with its increase: a few MWh may be “over saved” or “overproduced”, that is a small percentage over the 5-6 GWh used along the day. On the other side, with 3T contract the amount of energy saved is much more than the one used in the night, resulting in a consistent money saving for the consumer.

- As last row of Tab.5.25 shows, a small elasticity results in a more balanced management of energy: that is because small values of *e* make the user cut less power during the day, therefore there’s less amount of energy to shift into night period. This is particularly true for the 2T contract, while it’s not so for 3T one. The reason is given by the (5.8): huge ΔPs compensate the effect that *e* has on Q_{fin}.

Table 5-25: ΔEnergy for every new contract for each user

	BTN-A [MWh]		*BTN-B [MWh]*		*BTN-C [MWh]*	
e	**1T→2T**	**1T→3T**	**1T→2T**	**1T→3T**	**1T→2T**	**1T→3T**
-0.35	-4.499	102.236	-2.5128	136.413	23.468	228.413
-0.36	-4.628	105.565	-2.5846	140.311	24.138	234.939
-0.40	-5.142	117.294	-2.8717	155.901	26.821	261.044
-0.50	-6.428	146.618	-3.5897	194.876	33.525	326.305
-0.20	-2.571	58.647	-1.4359	77.950	13.411	130.522

$$Qfin = e * Qin * \frac{Pfin - Pin}{Pin} + Qin \tag{5.8}$$

Tables 5.16, 5.17 and 5.18 showed the expenses paid by each user in every contract type.

DR only in high tariff periods

Whether a consumer has as priority money savings, an option can be represented by cutting his load during the high-tariffs periods without moving energy into nighttime. This results in a "loss of comfort" [10] since less energy is used in the all day.

This scenario has been computed by evaluating the difference of power absorption caused by new remunerations, resulting in the following expenses values[28]:

Table 5-26: Expenses for every new contract for each user type

	BTN-A [k€]		***BTN-B [k€]***		***BTN-C [k€]***	
DR nature	1T→2T	1T→3T	1T→2T	1T→3T	1T→2T	1T→3T
Only load cut	432.582	420.921	561.351	546.329	707.546	691.565
Energy shift	439.378	428.833	570.018	556.014	716.908	701.569
No DR at all	458.749	468.237	596.285	608.195	753.520	782.639
Compared to 1T contract	1T	1T	1T	1T	1T	1T
No DR at all	423.602	423.602	547.889	547.889	675.579	675.579

Table 5.26 presents a summary of the amount of money for each study case: the less expensive, as expected, is the scenario with only power cut that result advantageous only by switching to a 3T contract (as can be seen comparing values with the last row, that is the starting contract situation used as reference). Moreover, that scenario is the only one for which is better to switch from a 1T contract to a 3T one: for all other cases the mono-tariff contract remains the best

[28] The "Energy shift" scenario (4th row) is the one previously explained. It has been reported in order to do an easier comparison.

choice from a consumer point of view. That leads to an important clarification: Demand Response programs are defined from DNO operators in order *for them* to avoid lines congestions. Tariffs schedule are an incentive that make consumers move production away from peak demand hours. Remuneration and other aspects are consequences that consumer (or the overall electric system) can benefit from, but it’s not the priority of a grid operator.

5.3 CONCLUSIONS

This chapter presented the study conducted in 5 months of work.

First, some analytical ways described how to get elasticity from power-remunerations plots. Since those graphs are available and easy to get, it represents a useful and easy-to-apply tool.

Then, a DR scenario invented by the author has been presented and applied on real data, in order to have a reliable comparison. Besides real-time elasticity values, a model based on their interpolation has been studied. In fact, the goal was to get an equation that allows the DNO to predict with very good precision how much power is going to be actually delivered on a specific day, since this amount could change from the contracted one due to particular conditions, weather *in primis*. Its reliability had been proved thanks to MAPE index, with good results. In fact, money waste due to wrong estimations has been computed, bringing encouraging results (only a little percentage of the total money would have been wasted). Then, a small comparison with a fixed elasticity value has been done in terms of power, showing that a more recent and flexible one is way more reliable.

In the third step, a little observation about DR on weekends has been done: if on Saturday it doesn't make a lot of sense moving huge blocks of power from days to nights (and it would bother the consumers since on weekends they may have different needs than during the week), on Sundays it's not possible to apply DR at all giving the actual contracts, because only one tariff is scheduled and no ΔP are then possible to compute.

In the next section it was done a simulation of a contract change. It may be mandatory indeed, both for a DNO and for a user, to be able to switch consumptions from specific hours (peak tariff hours) into others, resulting in less grid congestions, more stability, and less prices for the consumer to pay. For that reason 2 types of contracts have been discussed, a double and a triple tariff one. Only in this last case and under particular circumstances (no "energy moving", i.e. consuming less energy over the 24h without keeping it constant), it is convenient for a consumer to switch to a 3T contract. This brought to a final conclusion relative to DR: it is a program used by DNO to better manage power fluxes and, only as a secondary purpose, it can be used by final users to pay less bills.

6 Conclusions

This work started with the introduction to Demand Response, presenting it as a future mean to manage energy fluxes in a smart grid context. Since it requires efforts and knowledge from different fields (engineering, economic, juridical, environmental, social), lot of researchers have been involved in this particular program and lot of developments are still needed. Demand Response represents a tool that can be applied in any kind of context all over the world: that's why researchers from India, China, USA, Europe and other important zones are financially supported to find out new smart and efficient ways to introduce it into their electric system, whatever it is. In fact, it doesn't matter whether energy is produced by traditional power plants with a small penetration of RES, or if RES influence is very strong: power management will be always considered as an opportunity to optimize production, transmission and utilization costs. Obviously environmental issues have to be considered too, and fortunately target as "2020 climate and energy package" and long-term goal such as the "2050 Energy Roadmap" are driving technological progress into that direction.

Unfortunately economic benefits are often considered stronger motivations than environmental/technical ones, therefore a quick overview about different type of electric markets has been made. Focusing on this point, it must be reminded that DR is not supposed to be a way to earn money easily: its priority is indeed to move blocks of energy into different periods of the day to maintain grids constantly balanced. A contract switch was simulated to monitor these power fluxes changes due to tariff schedules. Analysis of economic consequences for 3 consumers types have been reported, showing that changing from a mono-tariff contract to a double/triple one is indeed never convenient. Participants of this program are in fact being paid, according to their actual contribution or on decided terms, but usually these amount of money results in a small-medium discount on the final bill. It's important to remember indeed that the goal is an economic optimization of the overall system, not only for consumers' point of view, in fact also production and transmission costs are included in the objective function to minimize. Economic impacts of different possible scenarios were presented for this reason, in fact the only grid stability is not the only criteria to choose a method over the others.

Consumers will bring to another topic that has been quickly mentioned: social knowledge and acceptance. Two options are indeed possible in order to move huge blocks of energy: a small number of big consumers or a big amount of little ones. Informing people about how DR works, how obtain benefits in terms of pollution and grid balance must be seen as a strong challenge since population may be reluctant towards a technology that (apparently) doesn't improve lives and is not so economically valid. In order to make it socially applicable, this work considered DR scenarios with constraints that may be accepted by the population: load cut only if consumptions exceed high power caps in particular periods and keeping the same amount of energy in the 24h are some of them. These constraints are chosen by the author and they are freely adjustable: for example parameters as elasticity, when it was used as an input value, was selected within a reasonable range.

In this particular case, i.e. when elasticity was used as an input value, literature and papers have been consulted in order to fix a proper range from which select a reasonable elasticity value. As already mentioned, most of them were referring to study cases before 2010, so that values may have changed considerably during the last years: this is the reason why new methods to get updated and more accurate values have been analyzed.

This report brought to a result that can have practical applications, that is the estimation of elasticity considering his change during the day and the weekends. Not only, also a way to obtain it from specific graphs was demonstrated. It is author's hope that these results will give some help in defining new updated elasticity values differentiating it for users classes.

Resulting papers

Working on this report has given the chance to write some papers signed by the author himself and his supervisors, prof. Zita Vale and prof. Pedro Faria of "ISEP – Instituto Superior de Engenharia do Porto". Those papers are going to be presented in conferences involving Demand Response topic.

Pierfrancesco Corsi, Pedro Faria, Zita Vale. *" Elasticity Parameter Definition and Analysis for Real-Time Pricing Remuneration Basing on Different Users Cases"* [Published in SEST 2019 conference and available on IEEE Xplore Digital Library]

Pierfrancesco Corsi, João Spínola, Pedro Faria, Zita Vale. *" Study case of price elasticity's predictability for BTE user type"* [Published in DREAM GO 2019 conference]

Pierfrancesco Corsi, Pedro Faria, Zita Vale. *"Effects of elasticity parameter definition for real-time pricing remuneration considering different user types"* [Published in ICEER 2019 conference and in press for the "Energy Reports Journal"]

Pierfrancesco Corsi, Pedro Faria, Zita Vale. *"Online Estimation and Use of Price Elasticity of Demand for Shifting Loads Through Real-Time Pricing"* [Submitted for PSCC 2020 – Power System Computation Conference]

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Attached Documentation

Table: 24h power values: tariffs are in [€/kWh], real power is in [MW], "cap power" stands for power after DR.

Hour		Value	*[MW]*	*Cap Power*	Hour		Value	*[MW]*	*Cap Power*
00:15	T3	0.1016	*5202.58606*	*5202.58606*	12:15	T2	0.1765	*5009.06685*	*5009.06685*
00:30	T3	0.1016	*5193.60081*	*5193.60081*	12:30	T2	0.1765	*5029.58376*	*5029.58376*
00:45	T3	0.1016	*5180.70770*	*5180.70770*	12:45	T2	0.1765	*5081.82233*	*5081.82233*
01:00	T3	0.1016	*5166.13504*	*5166.13504*	13:00	T2	0.1765	*5068.42056*	*5068.42056*
01:15	T3	0.1016	*5082.65782*	*5082.65782*	13:15	T2	0.1765	*4994.83332*	*4994.83332*
01:30	T3	0.1016	*5048.00384*	*5048.00384*	13:30	T2	0.1765	*4955.84441*	*4955.84441*
01:45	T3	0.1016	*4945.79368*	*4945.79368*	13:45	T2	0.1765	*4836.66468*	*4836.66468*
02:00	T3	0.1016	*4908.93272*	*4908.93272*	14:00	T2	0.1765	*4802.71828*	*4802.71828*
02:15	T3	0.1016	*4752.54123*	*4752.54123*	14:15	T2	0.1765	*4717.48842*	*4717.48842*
02:30	T3	0.1016	*4716.78384*	*4716.78384*	14:30	T2	0.1765	*4703.69406*	*4703.69406*
02:45	T3	0.1016	*4572.30371*	*4572.30371*	14:45	T2	0.1765	*4652.34444*	*4652.34444*
03:00	T3	0.1016	*4534.61148*	*4534.61148*	15:00	T2	0.1765	*4648.07156*	*4648.07156*
03:15	T3	0.1016	*4410.04946*	*4410.04946*	15:15	T2	0.1765	*4653.91729*	*4653.91729*
03:30	T3	0.1016	*4378.47006*	*4378.47006*	15:30	T2	0.1765	*4647.44505*	*4647.44505*
03:45	T3	0.1016	*4274.19825*	*4274.19825*	15:45	T2	0.1765	*4635.15869*	*4635.15869*
04:00	T3	0.1016	*4247.74090*	*4247.74090*	16:00	T2	0.1765	*4638.14150*	*4638.14150*
04:15	T3	0.1016	*4156.34987*	*4156.34987*	16:15	T2	0.1765	*4647.47854*	*4647.47854*
04:30	T3	0.1016	*4136.11115*	*4136.11115*	16:30	T2	0.1765	*4652.97034*	*4652.97034*
04:45	T3	0.1016	*4079.55884*	*4079.55884*	16:45	T2	0.1765	*4682.78988*	*4682.78988*
05:00	T3	0.1016	*4061.98542*	*4061.98542*	17:00	T2	0.1765	*4710.73546*	*4710.73546*
05:15	T3	0.1016	*4006.12926*	*4006.12926*	17:15	T2	0.1765	*4858.15325*	*4858.15325*
05:30	T3	0.1016	*3994.97722*	*3994.97722*	17:30	T2	0.1765	*4955.36892*	*4955.36892*
05:45	T3	0.1016	*3965.93220*	*3965.93220*	17:45	T2	0.1765	*5366.79767*	*5366.79767*
06:00	T3	0.1016	*3955.45336*	*3955.45336*	18:00	T2	0.1765	*5484.61118*	*5484.61118*

06:15	T3	0.1016	*3940.14699*	*3940.14699*	18:15	T2	0.1765	*5788.55214*	***5565.23290***
06:30	T3	0.1016	*3932.09580*	*3932.09580*	18:30	T2	0.1765	*5818.79016*	***5565.23290***
06:45	T3	0.1016	*3925.61018*	*3925.61018*	18:45	T1	0.2253	*5914.51145*	***5565.23290***
07:00	T3	0.1016	*3917.76245*	*3917.76245*	19:00	T1	0.2253	*5922.38692*	***5565.23290***
07:15	T2	0.1765	*3916.02061*	*3916.02061*	19:15	T1	0.2253	*5997.65854*	***5565.23290***
07:30	T2	0.1765	*3894.54622*	*3894.54622*	19:30	T1	0.2253	*6012.70322*	***5565.23290***
07:45	T2	0.1765	*3844.81441*	*3844.81441*	19:45	T1	0.2253	*6054.60038*	***5565.23290***
08:00	T2	0.1765	*3788.03257*	*3788.03257*	20:00	T1	0.2253	*6057.08581*	***5565.23290***
08:15	T2	0.1765	*3682.70551*	*3682.70551*	20:15	T1	0.2253	*6102.36341*	***5565.23290***
08:30	T2	0.1765	*3691.93271*	*3691.93271*	20:30	T1	0.2253	*6111.90504*	***5565.23290***
08:45	T2	0.1765	*3672.15857*	*3672.15857*	20:45	T1	0.2253	*6126.11484*	***5565.23290***
09:00	T2	0.1765	*3696.87917*	*3696.87917*	21:00	T1	0.2253	*6107.75866*	***5565.23290***
09:15	T2	0.1765	*3786.75734*	*3786.75734*	21:15	T2	0.1765	*6076.37282*	***5565.23290***
09:30	T2	0.1765	*3825.03806*	*3825.03806*	21:30	T2	0.1765	*6065.70908*	***5565.23290***
09:45	T1	0.2253	*3945.62828*	*3945.62828*	21:45	T2	0.1765	*6020.13602*	***5565.23290***
10:00	T1	0.2253	*3991.60330*	*3991.60330*	22:00	T2	0.1765	*6005.17943*	***5565.23290***
10:15	T1	0.2253	*4132.95383*	*4132.95383*	22:15	T2	0.1765	*5948.87470*	***5565.23290***
10:30	T1	0.2253	*4187.56947*	*4187.56947*	22:30	T2	0.1765	*5929.95846*	***5565.23290***
10:45	T1	0.2253	*4383.97559*	*4383.97559*	22:45	T2	0.1765	*5834.13628*	***5565.23290***
11:00	T1	0.2253	*4436.32023*	*4436.32023*	23:00	T2	0.1765	*5799.53615*	***5565.23290***
11:15	T1	0.2253	*4614.47933*	*4614.47933*	23:15	T2	0.1765	*5627.86613*	***5565.23290***
11:30	T1	0.2253	*4675.03644*	*4675.03644*	23:30	T2	0.1765	*5569.51036*	***5565.23290***
11:45	T1	0.2253	*4848.26761*	*4848.26761*	23:45	T2	0.1765	*5354.96056*	*5354.96056*
12:00	T1	0.2253	*4886.67032*	*4886.67032*	24:00	T2	0.1765	*5306.55398*	*5306.55398*