UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master's Thesis

"DESIGN OF A TARIFF SCHEME BASED ON COST CAUSALITY"

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Madrid, June 2016

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SUMMARY

The electricity bill in Spain presents a serious problem: the **outdated methodology for allocating network costs**, as billing is based on contracted power and energy consumed, where contracted power bears the greatest part.

The introduction of storage and customer self-consumption implies the need of a new network tariff design based on the information of smart meters. For this reason, it is necessary to design a methodology that will be explained in this thesis, to solve the new scenarios faced in the close future as: **Use the network or system and self-consumption, electrification of demand o use of batteries.**

This thesis proposes a methodology for allocating network cost based on cost drivers (hourly network cost) and provides flexibility, according to the cost per voltage level, and the new challenges that we face with the increase of the distributed generation. The user will pay for the **use of network** rather than the contracted capacity.

With the implementation of the new methodology the following benefits are achieved:

- The new tariff reflect the real cost of the electricity consumption: the peak consumption will include the energy cost, more generation power and network (T&D) and the off-peak consume will include only the generation cost.
- Clear price signal to the consumer: Consumers will know and decide when they must try to consume.
- Electrification: one of the most important consequences of the new methodology is the increase of the electrification in off-peak hours where the energy price is too low and the network access tariff is low.
- Demand management: consume in hours with low demand has an incentive. Domestic consumers are able to charge batteries to use it when there are peak hours. This will create changes in the monotone and the prices.
- Groups: The cost of a client group is the same as the sum of the each customer costs.

In addition, it allows us to achieve one of the main challenges for the current electricity market, which is the transition from a passive consumer to a **more active consumer.**

The consumption period becomes crucial, so that will allow **modification of consumer behavior**, shifting consumption from peak hours to the hours in which energy is cheaper. All this is an important step because it allows: **Efficient network prices, to issue clear price signals between peak and peak-off hours and hourly prices allow an efficient network cost allocation for customers with self-consumption.**

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1. INTRODUCTION

The electricity system is in a transitional phase towards a more dynamic energy model, in which the role of the new factors will allow the consumer to become a protagonist, and will be of critical importance. These factors include a flexible generation, energy storage and the mass introduction of electric vehicles. Simultaneously, we are living during a time of progressive electrification of society due to the increasing weight of electricity in our lives, which is explained by the introduction of electricity in energy uses such as in transportation. In this context, consumer participation is a key player in the electricity system.

Additionally, the quest for a more efficient and environmentally friendly energy consumption makes it necessary for the relationship between energy and society to adopt a more active role on behalf of consumers. To do this, consumers must have a better understanding of how electricity is consumed and which are the best practices regarding efficient electricity consumption.

The main changes that will give rise to a new scenario are:

- Customers taking on the additional role as producers
- Access to information allowing consumers to make informed decisions
- Progress towards a more elastic demand
- Changes in network use: consume and pour energy, battery use…

Management of such changes to ensure the development and maintenance of a well-adapted, reliable power system requires updated regulations that keep pace with the evolution of technology and end-user needs. Regulators are faced with the challenge of ensuring electricity service business models that align with policy goals, including the reliability and quality of electricity supply, encouragement of innovation and economic growth, and the development of clean energy technologies for decarbonization. As the distribution system transitions from a passive network of consumers to a more actively managed system of network users with diverse consumption and production behaviors, price signals will play a crucial role in shaping the interactions between the physical components of the distribution system and network users.

In this sense, as the nature of network use is transformed, regulators must entirely rethink the design of network charges.

1.1. Motivation

New concepts appear following the need to define and influence the design of tariffs:

- Use the network or system and self-consumption: Now, consumers can choose to either consume or self-produce all their energy. Consumers who choose to self-produce remain connected to the system to ensure an electricity supply. These consumers will have to contribute to costs and system services for the self-consumed energy generation facility when the consumer is entirely or partially connected to the electrical system.

- Electrification of demand: Consumers and suppliers seek energy efficiency of not only electricity, but also alternative energy sources. Faced with a change in the price of electricity, customers consider the price of other energy sources before making a decision. This increases the elasticity of demand and active demand management.

- Use of batteries: Batteries that efficiently store energy produced by the sun may be used in homes, regardless of electrical networks.

Current tariff structures do not consider the future of the electrical system. A new tariff scenario is necessary to adapt the scheme to align the electricity tariff with future challenges. Without sacrificing efficiency, it is necessary to issue clear economic signals in the decision-making of all market participants. Tariffs are the primary means of exchange of information between businesses and consumers.

According to economic theory, in a market economy the most efficient economic signal in any activity is achieved with the application of marginal costs. In market economy, marginal cost provides:

- Income adequacy
- Efficient allocation of cost
- Cost transparency

However, in the case in electric transmission, their application fails to produce enough revenue to recover the full costs.

If the possibility of using the marginal costs is ruled out, the search for efficiency leads to cost allocation based on the analysis of causes of their own costs of the activity.

This approach could improve the design of an efficient tariff network, without losing sight of the objective pursued by the marginal costs: tariffs achieve that result in an efficient allocation of resources by transmitting a signal to consumers the cost it poses to the system and provides mechanisms to adapt to new needs and challenges of current and future electricity market.

The new tariff must meet certain requirements to give optimal economic signals:

- Income adequacy
- Efficient allocation of costs
- Transparence
- Non discriminatory
- Consider new network uses
- Efficient electrification of demand
- Adapt to possible changes in the consumption profile

The goal is to find an allocative methodology for network tariffs to ensure income adequacy, transparency and efficiency in the allocation of costs between different supplies so that prices reflect the costs they incur to consumers and charging system sunk costs the least distorting way possible global consumption, and moreover to respond to new network uses.

Tariffs must send <u>efficient economic signals</u> in short and long-term decision making.

- Short-term energy signals, as close as possible to real time, to promote the efficient functioning of the system and facilitate decisions to generators and consumers.

- Long-term signals, in order to promote efficient investments and recover total costs of the activity.

In the new free market context, transmission has become the meeting point for the various players interacting on the wholesale market. The amount to be paid by each player for using the network or the benefit obtained from its use must be determined, as this charge affects each actor's competitive position.

Regulation of the transmission network should answer traditional questions such as:

- Who reinforces the network when needed?
- Who can connect to the network?
- What happens when the network becomes congested?
- How should the network costs be allocated?
- Who pays for the power losses that take place in the network?

Consumers must be provided with sufficient flexibility that can adapt to new habits, new generation models and other ongoing challenges.

Other factors that need to be taken into consideration in tariff design include the cost of supplying electric power depending on when and where it is consumed, differentiation of geographic areas and evolution of the peak system price.

1.2. Objectives

The ultimate goal is to design a tariff structure based on cost causality, which indicates to consumers actual costs incurred by the system network. Agents cover their income and find incentives to be efficient.

The network is designed to deliver energy during peak demand. We need to invest in network development with increasing peak demand of the system. Therefore, the cost of the networks must be allocated at the peak hours for each voltage level. That cost will be the cost drivers, that is, the demanded power in the peak of the system.

The traditional way to shift the costs of network equipment conventional measures has been to use the contracted power. It was assumed that the contracted power was the best estimate made by the consumer of the maximum power demand on the peak. But the term power does not include incentive to consume less during peak hours, so it is not an adequate indicator.

If the traditional billing based on contracted power and energy consumed is not efficient when allocating fixed costs, it is necessary to replace the power term for an hourly billing. The project will focus on this aspect of the tariff.

The objective of the work is: the design of a suitable tariff methodology that makes consumers change their consumption behavior based on the economic signals, and studies new situations that appear after applying the new methodology.

Designing a new methodology for billing allows customers pay for their actual contribution to the demand:

- Have a bill based on hourly billing instead the contracted power.
- Change the aggregate demand, to allocate costs to each voltage level

2. PRESENTATION OF THE PROBLEM

We are proposing a change of network tariffs to adapt to the new uses and technological developments because the current tariff (and network with the same structure as the current) does not solve it.

2.1. The energy cost.

Components of energy costs and their nature:

- Daily market price: hourly price set on the wholesale electricity market.
- Cost of deviations: Corresponds to the extra costs faced by the buyer for the difference between the purchase on the market and actual consumption
- Cost other system services (costs that are not related with demand)
  - Costs of adjustment services. Technical constraints, power reserve up.
  - Capacity payments. Investment incentive + availability incentive in €/ MW to the central.
  - Interruptibility service. Payment in €/MW to customers by providing the service.

Capacity payments are billed in €/MWh by period of the corresponding tariff and interruptibility service is billed in €/MWh. Capacity term is the price consumers pay for the power contracted for your installation. It is a fixed cost that doesn't depend on consumption.

The amount to be paid for this item is obtained by multiplying the contracted power by the billing period and by the power charge price, which depends upon the rate type.

The cost per Interruptibility is that the System Operator pays certain large consumers to commit to stop using those times when the grid needs more power available. Thus, when demand peaks occur, reducing consumption by these consumers guarantees the stability of the system.

As this way of allocating costs doesn’t correspond to their nature, these energy components are also considered in the methodology that is being proposed.

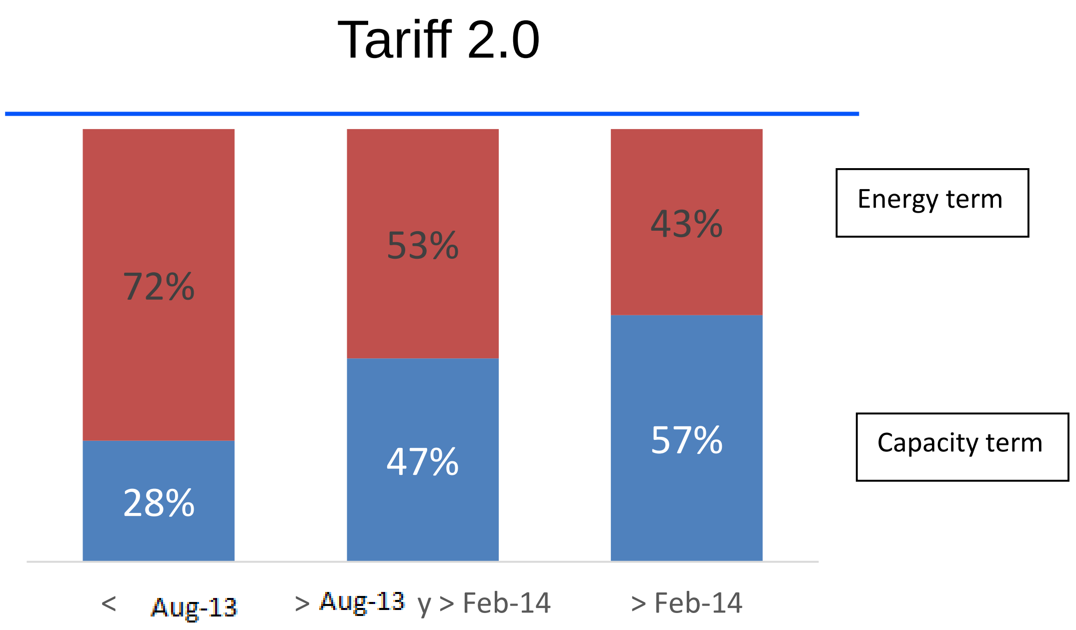
2.2. The nature of the network costs

The network is designed to deliver peak demand. We need to invest in network development with increasing peak demand of the market.

The CNMC guideline states: "Network tariffs are calculated additively and depending on factors that induce the cost of networks, peak power tariff of each voltage level is an essential factor in network design".

The traditional way to allocate network costs with conventional meters has been using the contracted capacity. Being the contracted power the best estimate that the consumer makes of his maximum demand.

Nowadays most weight is placed at the capacity term. As we can see in the following graphic, the access tariff capacity term grew a lot being higher than the energy term in the in the price updates carried out in 2013 and 2014. Moreover, the capacity term weight in the proposed CNMC network tariffs is even higher.



2.3. Components of charges

The charges are collected in the access tariffs, but there is no allocation methodology to this day.

The main components of these charges are:

- Tariff deficit annuities.
- Incentives for cogeneration and renewable
- Over-cost in SENP (Electrical Non mainland systems).

2.4. Why a reform is necessary?

The current methodology presents two serious problems:

- Excessive charges: Almost 50% of the final cost is taxes and charges used to recover the cost of energy and climate policies. The consequences are:
  - Loss of competitiveness vis-à-vis other fossil energy sources
  - Barrier to electrification.
  - Regression of charges

  But the solution to this problem is as simple as remove them from the bill, and we are not going to study this problem in this methodology.

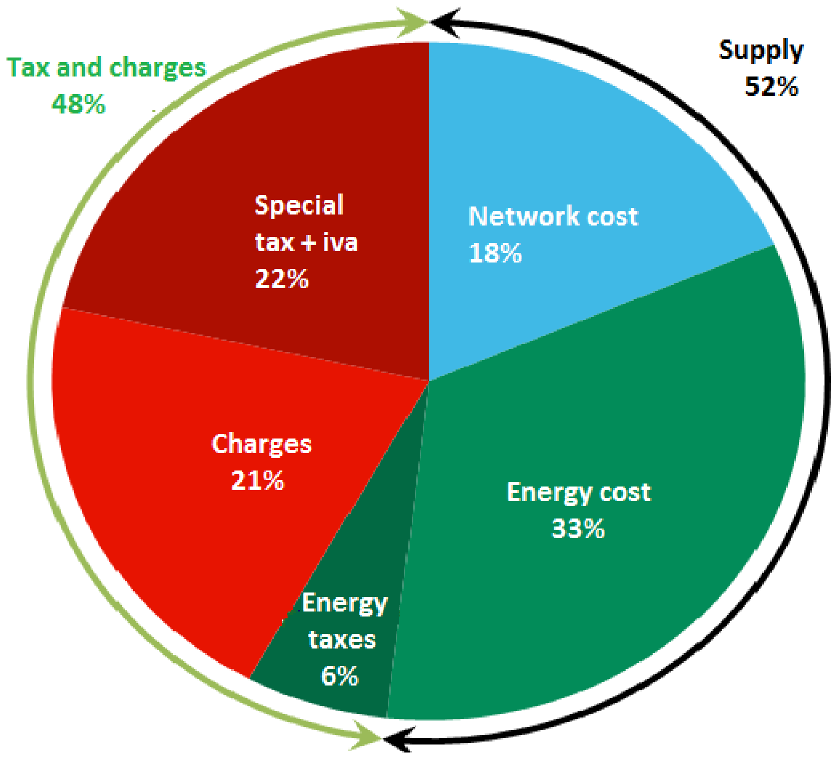
- Obsolete structure allocating network cost: based on contracted power and energy consumption billing:
  - Inefficient when allocating fixed costs because new concepts have appeared. As mentioned before, we are living a process of progressive electrification of society, which seeks efficiency that considers electricity and alternative energies and the increase in the distributed generation use and their correct signals.
  - Optimizes the bill artificially by aggregating consumption.

There are already some proposals bringing down charges in the electricity bill. Here we are going to propose a methodology for allocating network costs.

3. CURRENT METHODOLOGY FOR CALCULATING NETWORK TARIFFS

3/2014 guideline, of July 2, of Comisión Nacional de los Mercados y la Competencia (CNMC) establishes the methodology for calculating the annual prices access of network tariff to transmission and distribution of electricity today.

The cost breakdown of the Spanish electricity bill in 2016 is as follows:



At present the electricity tariff charges network tariffs together without making a detailed differentiation or separation of network costs and charges.

Article 16 of Law 24/2013 Electricity Industry lays out the difference between access cost to networks and related charges system costs:

- The prices of tariff access to transmission and distribution networks will be established in accordance with the methodology established by the CNMC considering for these purposes the cost of the remuneration of these activities.

- The necessary charges shall be established in accordance with the calculation methodology to be established by the Government on the report of the CNMC, covering system costs to be determined, without prejudice to the transportation and distribution cost.

The solution of the charges is as simple as removing charges of the tariff , or at least that they don't distort, but this methodology does not propose a tariff change network because the charges are a problem, but because the rate does not fit to new scenarios.

There is a CNMC network tariff methodology approved in 2014. However, this methodology has not been applied yet, because it has not been approved the charges methodology.

3.1. Scope of that methodology

Consumers, producers, own consumption of producers, self-consumers (for the energy consumed or fed into the grid, depending on the mode of consumption), pumping stations, exports and imports.

3.2. Tariff principles

- Sufficiency: Network tariffs, resulting from the allocation of transport and distribution costs, guarantee the recovery of these costs, according to the forecasts.
- Efficiency allocating network costs for each tariff group according to the principle of causality, avoiding cross-subsidies between tariff groups and encouraging the efficient use of the transport network and distribution.
- Additivity: Network tariffs include additively transport costs and distribution that corresponds to each rate group.
- Transparency and objectivity.
- Non-discrimination in transport and distribution network tariff among network users with the same characteristics (connected to the same voltage level rate and with the same time discrimination), belonging to the same tariff group.
- Network tariffs are unique throughout the national territory.

3.3. Costs including network tariffs

- Annual remuneration transport and distribution, including commercial management cost recognized to distribution companies (i.e. metering, billing, access management, etc.).
- It can be considered as a cost the difference between planned and actual income.
- Revenues from network tariffs of producers are discounted from the cost because the cost of the networks is assigned to customers, producers… Similarly, revenues and costs of intra-Community transport, international connections and management treated restrictions are considered as such.

3.4. Definition of tariff groups and network access

- Customers:
  - Same existing structure (The existing tariffs which the consumers can choose are 2.0A, 2.0 DHA, 2.1 A, 2.1 DHA, 3.0 A, 6,1 A or 3.1 A, 6.1 B, 6.2, 6.3 and 6.4 the first number is the number of tariff periods and the number before the point is the tension level 0 for low voltage, 1 for medium voltage and high voltage for the rest), although grouping low voltage up to 15 kW and 6.1 apply network tariffs to all medium voltage.
  - Tariff 6.5 is considered the network tariffs for exports, which will have the same power and energy price terms as network tariffs 6.4.
- Producers: variable term of 0,5 €/MWh.
- Imports: The network tariffs will be the same as that applied to electricity producers located in national territory.

The network access classification according to the Circular:

Nivel de tensión		Tensión de suministro (kV)		Potencia de suministro (kW)		Acceso
		mínima	máxima	mínima	máxima	
Baja tensión	NT0	-	< 1	-	15	2.0TD
				> 15	50	3.0TD
Alta Tensión	NT1	1	< 36	-	-	6.1TD
	NT2	36	< 72,5	-	-	6.2TD
	NT3	72,5	< 145	-	-	6.3TD
	NT4	145	-	-	-	6.4TD

3.5. Time discrimination

Proposed by the SO, same schedule for Peninsula, Balearic and Canary Islands, Ceuta and Melilla with redefinition of seasons for each area and same time periods, 3 periods of low and medium voltage would consider morning and afternoon rush.

Peak periods are re-concentrated in the winter months and off-peak period is in summer months (July) for distributed generation.

3.6. Allocating costs of transmission and distribution

- Break down distribution costs by voltage level from the information declared by distributors in Circulars CNMC, using the same percentages from the guideline we determine the cost of each voltage level.

	Coste de transporte	Coste de distribución			
	NT4	NT3	NT2	NT1	NT0
Coste de redes de 2014 a recuperar por nivel de tensión tarifario (miles €)	*1.358.012*	*467.202*	*481.508*	*2.217.668*	*1.787.267*
% de coste sobre total	*100,0%*	*9,43%*	*9,72%*	*44,77%*	*36,08%*

- Assign the cost associated with the power and the energy consumed from executions Network Reference Model Base Zero (MRR) in 2004 and 2006
- Divide the costs associated with the power and energy term at the end of each time period. It established 876 peak hours (10% of hours).

- The costs of each level of voltage and time period are allocated between users according to a simplified network model:
    - Costs associated with the capacity term by voltage level are assigned considering the balance of power flowing to lower voltage levels when is peak demand for each time period.
    - Costs associated with energy term are allocated considering the energy balance according to time discrimination.

For a client, therefore, the methodology assigns costs for the power and voltage level at which it is connected and the share of power and energy costs of higher voltage levels. Since the allocation of both capacity and energy terms are pre allocated to each customer for the costs of its tariff level and higher levels, the resulting charging structure is binomical for all customers (the energy term is between the 10% and 31% of the average network access tariff).

3.7. Commercial management costs

They are distributed according to the number of consumers in each tariff group (1,98 €/ customer per year) and begins assigned to the capacity term in proportion to the costs of transmission and distribution tariff assigned to each tariff group.

3.8. Application of the network access tariffs

The billing terms of power and energy are estimated, without considering the hourly behavior and the network use of self-consumers.

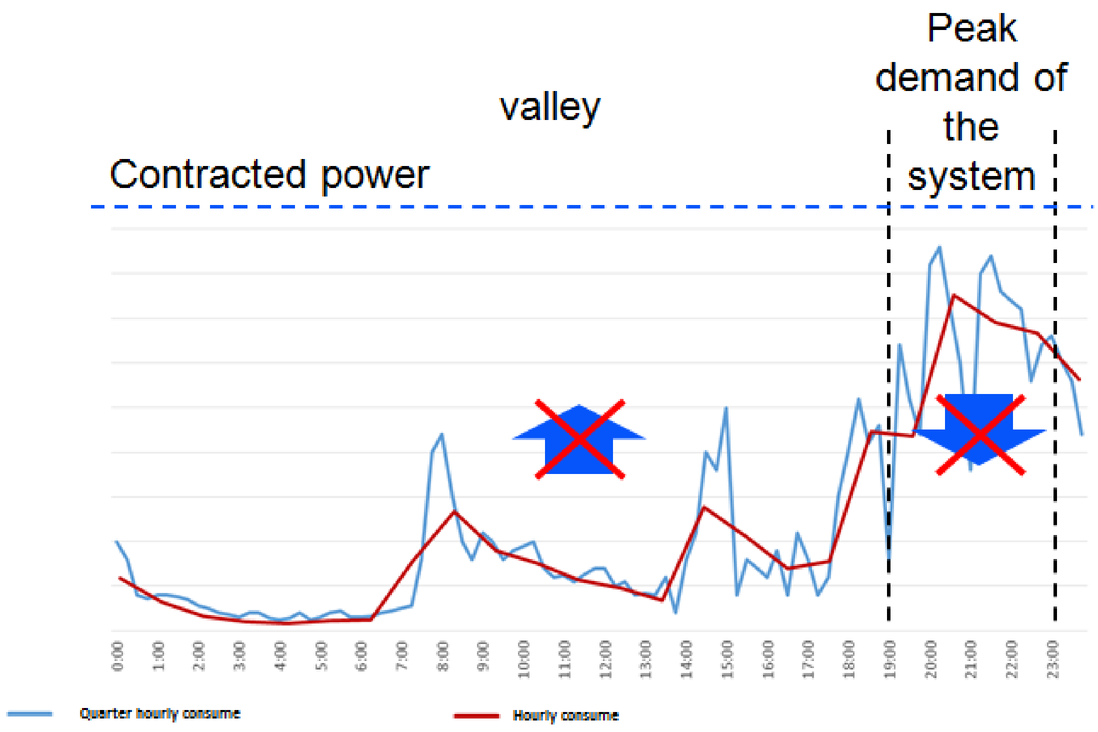
3.9. Problems of the actual methodology

The current methodology has characteristics that makes difficult to meet some objectives:

- The domestic client, without a maximeter, is paying a capacity term for the contracted power, regardless of how is their real hourly energy is consumed or its impact on the networks.

The result is that the current structure doesn't incentivize to:

- Have a lower consumption in peak demand periods of the system.
- Move consumption to off-peak hours.



- By aggregating consumers, some savings are achieved by reducing the contracted power due to the simultaneity factor.

  The problem is that the maximum power demanded by the group is not reduced, so these savings are not reserved for the system.

- Often, the electric vehicle charging point cannot be unified with the customer. That situation forces consumers to contract another supply, with its corresponding power.

  Due to this situation, electric vehicle charging is more expensive than it could be.

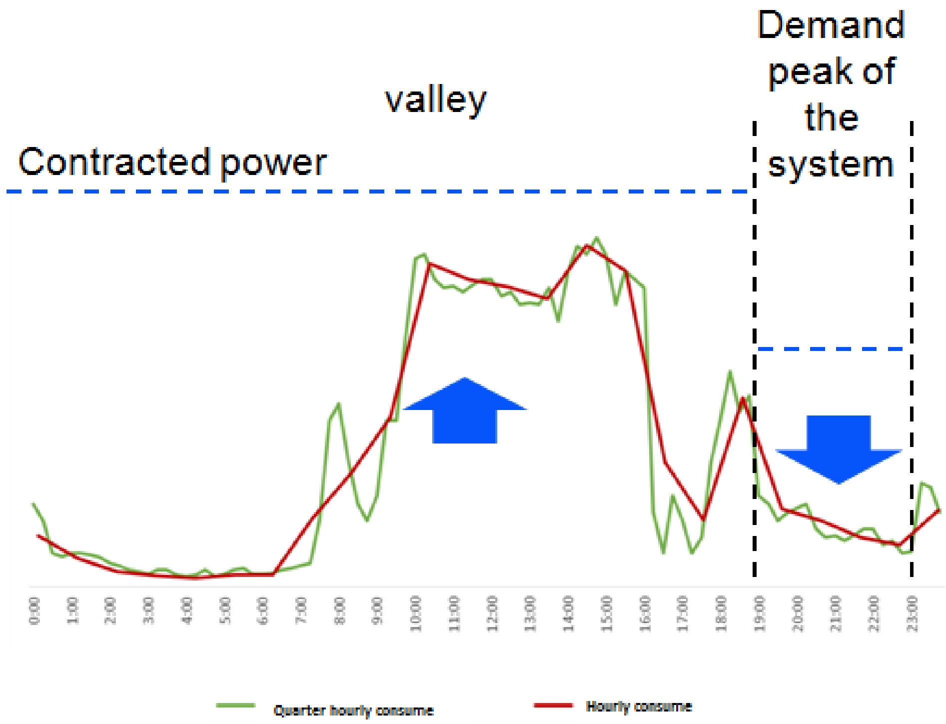
- Households suffering from energy poverty try to minimize their consumption but they always have to pay the capacity term, so, they can't reduce their electric bill as much as they want.

- The self-consumed energy stops paying most of the charges contained in the variable term of the network tariff.

  - Network tariff variable term contains most of the charges. The energy self-consumption consumed by network is reduced, avoiding paying charges.
  - The charges not paid by the self-consumption should be financed by the other consumers. This is a cross-subsidy between customers.
  - Storage to manage self-consumption and reduce the contracted power, failing to pay charges that are within the capacity term.
- MV and HV clients gets their objectives partially, as they have a maximeter:
  - 3 periods client : pays the term power for the contracted power (with bonuses of 15% maximum, if the power maximeter is below)
  - 6 periods client: pays the power term for the contracted power (there is only penalties)

Due to that is encouraging to design a new tariff to:

- A consumer behavior with less consumption in peak periods (although periods and fixed prices could be very elastic, but the implementation of smart meters will allow predict them)
- Move consumers consumption to off-peak hours, obtaining significant savings in the final bill.



4. PROPOSAL

Nowadays, with the installation of smart meters, it is possible to know the contribution of each client to the peak demand precisely, not only for the aggregated demand but for each voltage level, and it opens a door to allocate network costs more efficiently.

- Replace the capacity term for an hourly billing. That is easier with the new smart meters.

Because of the followign reasons change from old meters to smart meters is required

- The old meter instruments have some problem, as they give limited information.

  The demand that they measure is not hourly so they won't give efficient signal to decide when the consumers are consuming more.

  The measurement is for a billing period. The contracted power is used as an instrument of control and billing.

- Smart meters give much more useful information to the final user, using hourly demand that will facilitate the efficient consumption, measure and billed.

  In addition, you can cut remotely on a network emergency.

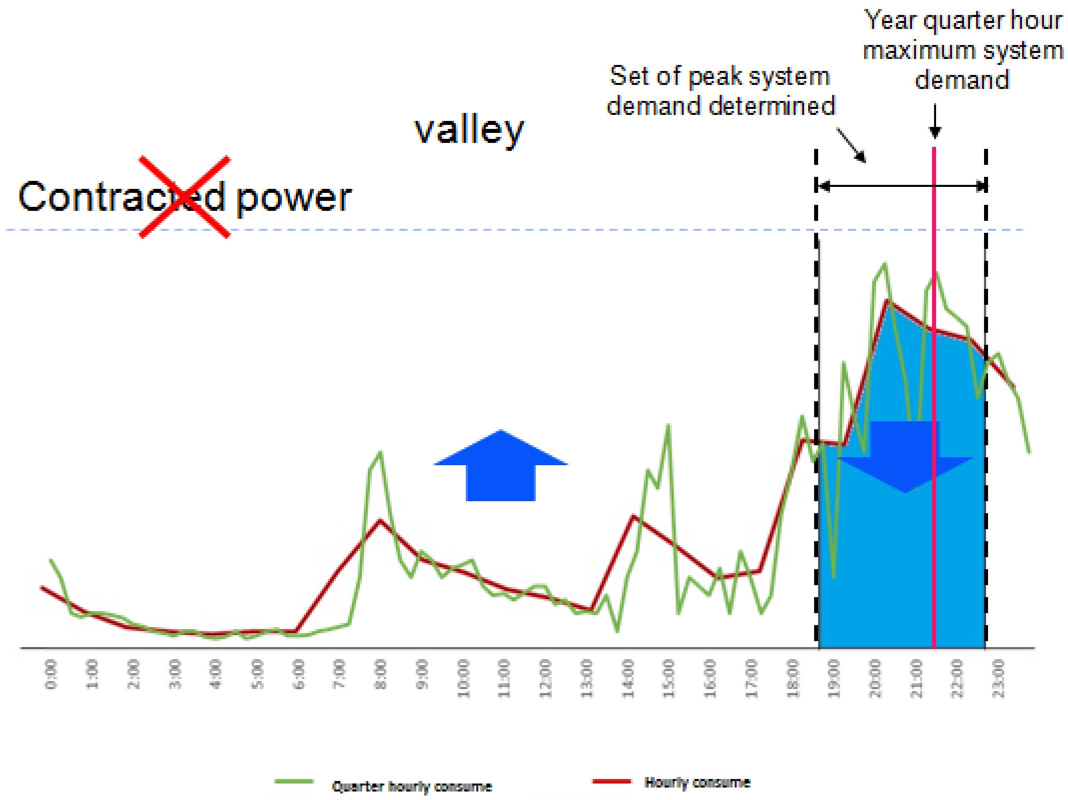
  Furthermore the voluntary price for small consumer has led to the development of the systems needed to measure and check the hourly consumption of all consumers. With the installation of smart meters, it is possible to know the contribution of each client to the peak demand precisely, not only for the aggregated demand but for each voltage level, and it opens a door to allocate network costs more efficiently.

The smart meters installation will be mandatory from 2019 in Spain.

The current billing network tariff has contracted capacity (€ / kW year) and energy, variable by periods (except 2.0 and 2.1 for the power term) (€ / kWh).

Instead contracted power, the power in the demand peak of the system is similar to the energy demanded in peak hours.

This encourages to less consumption in peak periods, peak period defined, in a dynamic way, According to the forecast demand and distributed generation and to move consume to valley hours.



5. PROPOSED METHODOLOGY

5.1. Data inputs

The data inputs used to implement the new methodology consist in a combination of:

- The total demand consumed in the year 2014 in an hourly basis, that is the aggregated-consumption measured by voltage level in the mainland system. This information is published by REE.

  The separation per voltage level that is used is:

  - Demand in voltage level 0 is the low voltage.
  - Demand in voltage level 1 will include voltages from 1 to 36 kV.
  - Demand in voltage level 2 will include voltages from 36 to 72,5 kV.
  - Demand in voltage level 3 will include voltages from 72,5 to 145 kV.
  - Demand in voltage level 4 will include voltages higher than 145 kV.

- The cost of transmission and distribution for 2016 are taken from the document "Memoria-orden-peajes-electricidad".

  Other items of cost and revenue forecast settlements are added to that cost as we can observe in the table below.

  Estimating income from insular systems is discounted (the demand in each tariff group in the insular system is subtracted proportionally by the contribution of each tariff group to the income of each). This is required, as the total demand is not available.

  The quantity is 264.962 thousands of euros from the insular systems, Ceuta and Melilla that will be subtracted.

  Fixed costs of energy are included in the model (capacity payments and interruptible service costs), which are recognized in peak hours total demand (energy circulated in NT4). The quantity from P x C + Interrumpibility is + 1.062.000 thousands of euros.

  Raising demands measures by voltage level to higher voltage levels, affecting them the corresponding losses.

Transmission (thousands of €)	1.536.961
Transmission retribution	1.742.980
Incentive to the availability of the Transmission network	28.843
Tariff revenue from generators	-98.862
Management interconnections	-136.000
Distribution (thousands of €)	4.777.624
Distribution retribution	4.935.248
Incentive to the availability of the distribution network	81.157
Distribution business management	56.700
Reactive and power excess	-261.997
Tariff revenue from generators	-33.484

- The cost of each voltage level will be shared Proportionally to the share made in the CNMC guideline, having the following distribution applying the percentages from the file: if we apply those CNMC percentages to the total demand for 2016 we will obtain the cost for each of the voltage level to apply in the new methodology:

Voltage level	Thousands of €
VL4	2.499.341
VL3	454.327
VL2	477.197
VL1	2.242.977
VL0	2.242.977
Total	7.342.073

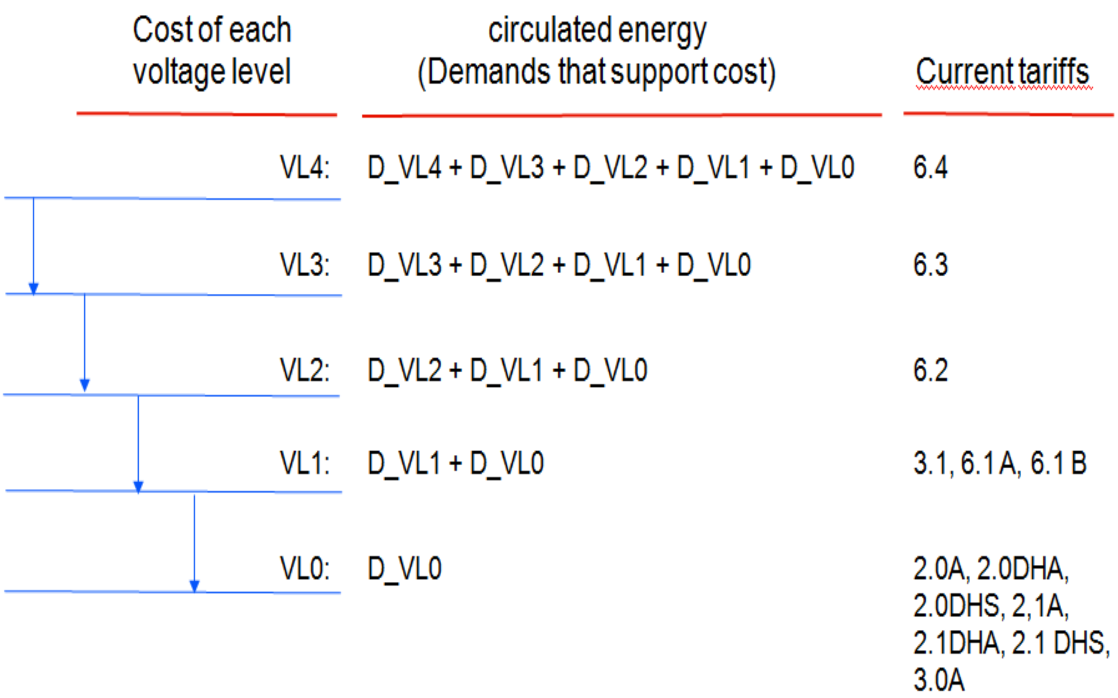
5.2. Cost allocation

We will see a change for allocating costs to arrive at the new tariff.

This methodology should allocate costs to the main cost drivers. The key driver of distribution and transmission network costs is the need to design the network to accommodate peak power flows, although the peak is not the only driver. The tariff will depend on the connection cost to the clients too.

We assume that the cost of each voltage level is borne by the energy circulated in peak hours of this voltage level. To calculate these peak hours we consider those when demand is greater than a percentage (%) of maximum hourly energy circulated. In our methodology we will set that percentage in 80%.

The current tariffs are at the same voltage level is unified and clients demand will have to face prices at peak hours of his voltage level, and those levels above him.



Step 1: Computing floor price

10% of the costs are charged by voltage level circulated to all circulated energy and not just to the peak hours. That 10% will be justified as operational and maintenance cost.

The price to be charged in the LV at all hours (€ / MWh) will be calculated following the next steps:

- We calculate the 10% of the cost of each voltage level.
- Calculation of the total demand per voltage level as the summation of the hourly demand of its own voltage level adding the demand in the upper levels multiplied by the average losses to rise it to the upper levels.
- Calculation of the price per voltage level dividing the 10% of the cost to the total demand, both of the in the same voltage level.
- Finally to obtain the price to be charged in each VL as floor price we will have to sum the price in their own voltage level to the upper prices carried to that voltage level (It will be applied if the VL have upper levels, if it hasn't, as in VL4 case, will be its own price).

Voltage level	Cost (thousands of €)	10% of the costs (thousands of €)	Circulated energy (TWh)	Price (€/MWh)	Price to impute in VL in all hours (€/MWh)
NT0	1.768.231	176.923	8,53	1,76	4,77
NT1	2.141.977	214.197	48,27	1,22	2,81
NT2	477.197	47.197	59,03	0,25	1,53
NT3	454.327	45.432	69,12	0,22	1,29
NT4	2.499.341	249.934	89,48	1,07	1,07

As an example, price to impute to floor demand in VL0 is computed:

$$\mathbf{4,77 = 1,76 + 1,22 \times (1 + \mathit{losses}_{01}) +}$$

$$\mathbf{0,25 \times (1 + \mathit{losses}_{02}) + 0,22 \times (1 + \mathit{losses}_{03}) + 1,07 \times (1 + \mathit{losses}_{04})}$$

Where $losses_{01}$ are the average losses to raise losses from VL1 to VL0 and are equal to 7,44%.

$losses_{02}$ are the average losses to raise losses from VL2 to VL0 and are equal to 9,27%.

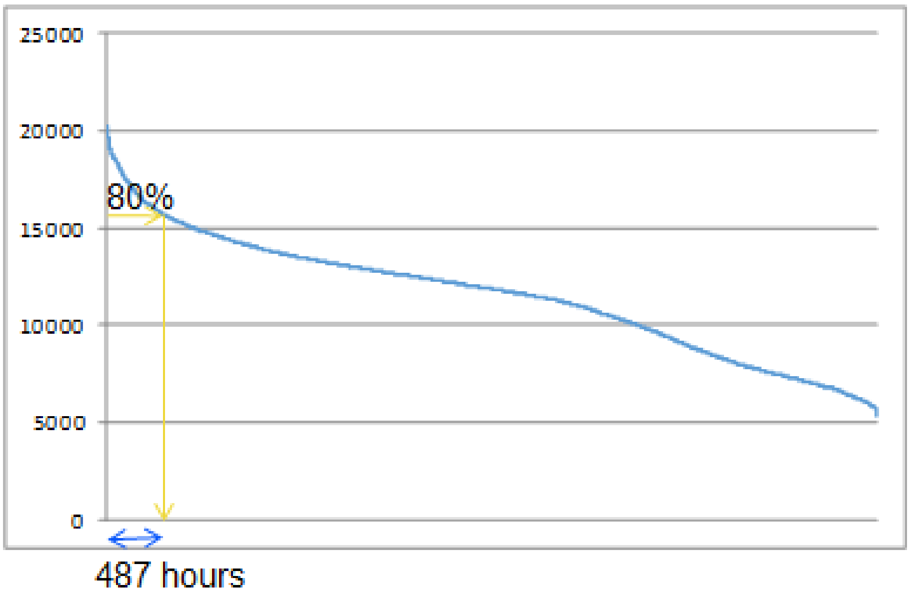
$losses_{03}$ are the average losses to raise losses from VL3 to VL0 and are equal to 10,58%.

$losses_{04}$ are the average losses to raise losses from VL4 to VL0 and are equal to 12,07%.

Step 2: Computing peak prices

To obtain the prices for the consumers that consumes on the peak hours we have to do a simple division between the 90% of the cost in the voltage level(this 90% is the total cost less the 10% corresponding to the floor prices which is justified as the cost of the commercial activities, meter reading…) and the summation of the demand of the peak hours (hours which consumption is higher than the 80%).

For example, for the peak price of voltage level 0 we draw the monotone of the circulated energy.



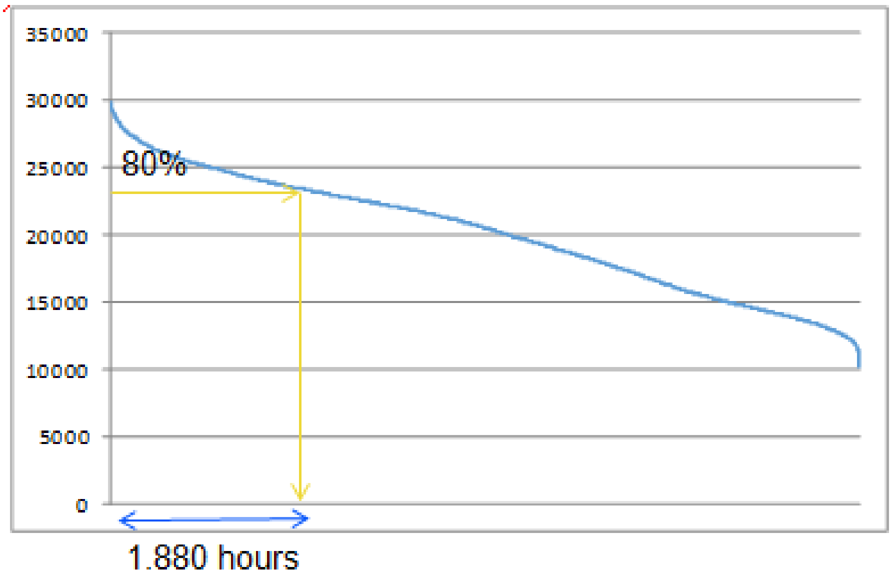
We observe that the maximum energy circulated is 20.249,227 and if we apply the 80% to that maximum energy circulated, only 487 hours of the 8.760 that has a year are low voltage peak hour.

To calculate the price of those peak hours:

$$\frac{\mathbf{0,9\ x\ LV0\ cost}}{\mathbf{\Sigma_{D>80\%} D_{LV0}}} = \frac{\mathbf{1.592\ M€}}{\mathbf{8,53\ TWh}} = \mathbf{186,75\ €/MWh}$$

For the peak price of the VL1 we draw the monotone curve of the circulated energy, in this case the demand will be the sum of the demand of the own voltage level and the demand of peak hours from VL0 taken to VL1 with the estimated losses (8,10%) in peak period.

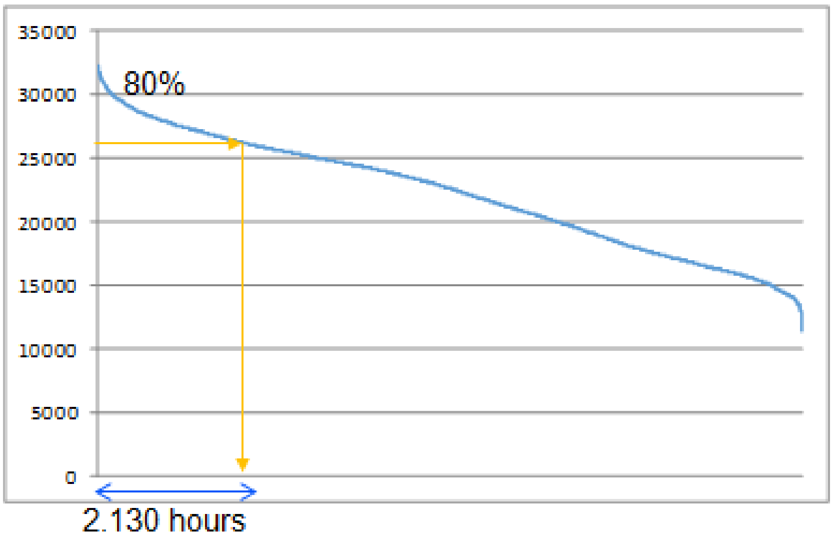
Following the example of VL0, we calculate the peak price for VL1:



$$\frac{\mathbf{0,9\ x\ LV1\ cost}}{\mathbf{\Sigma_{D>80\%}(D_{LV1}+D_{LV0})}} = \frac{\mathbf{1.928\ M€}}{\mathbf{48,28\ TWh}} = \mathbf{39,93\ €/MWh}$$

So that, the consumers will pay 39,93 €/MWh during the 1.880 peak hours.

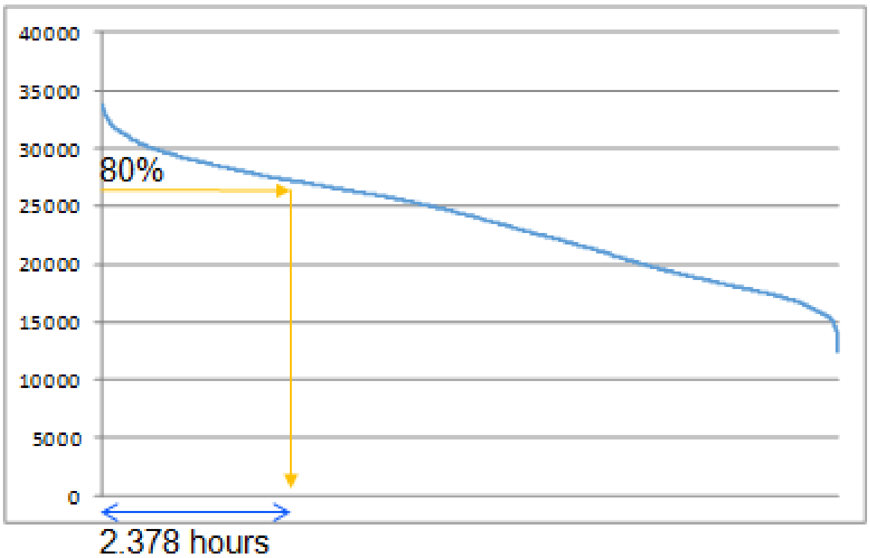
It will happened the same for the following voltage levels, for VL2 the estimated losses in the peak period will be because of taking VL1 (1,81%) and VLO (10,11%) to VL2. The monotone curve of the circulated energy will be:



$$\frac{\mathbf{0,9\ x\ LV2\ cost}}{\mathbf{\Sigma_{D>80\%}(D_{LV2} + D_{LV1} + D_{LV0})}} = \frac{\mathbf{429\ M€}}{\mathbf{63,32\ TWh}} = \mathbf{6,78\ €/MWh}$$

The price for the 2.130 VL2 peak hours will be 6,78 €/MWh.

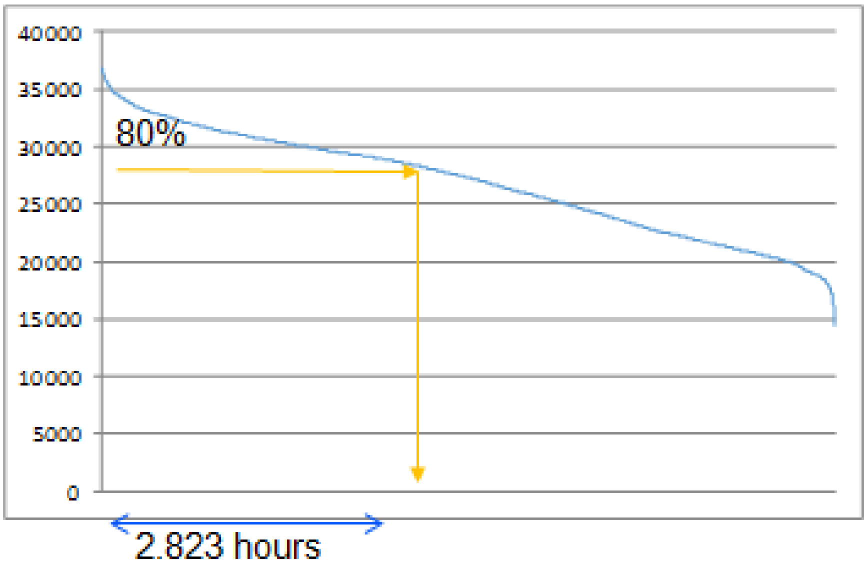
VL3 estimated losses in the peak period will be because of taking VL2 (1,37%), VL1 (3,2%) and VLO (11,65%) to VL0. The monotone curve of the circulated energy will be:



$$\frac{\mathbf{0,9\ x\ LV3\ cost}}{\mathbf{\Sigma_{D>80\%}(D_{LV3}+D_{LV2}+D_{LV1}+D_{LV0})}}=\frac{\mathbf{409\ M€}}{\mathbf{74,51\ TWh}}=\mathbf{5,48\ €/MWh}$$

The price for the 2.378 VL3 peak hours will be 5,48 €/MWh.

Lastly for VL4 estimated losses in the peak period will be because of taking VL3 (1,71%), VL2 (3,27 %), VL1 (5,43 %) and VLO (13,05%) to VL0. The monotone curve of the circulated energy will be:



$$\frac{\mathbf{0,9\ x\ LV4\ cost}}{\mathbf{\Sigma_{D>80\%}(D_{LV4}+D_{LV3}+D_{LV2}+D_{LV1}+D_{LV0})}}=\frac{\mathbf{2.244\ M€}}{\mathbf{91,53\ TWh}}=\mathbf{24,57\ €/MWh}$$

The price for the 2.823 VL3 peak hours will be 5,48 €/MWh.

The table below shows a summary of the results:

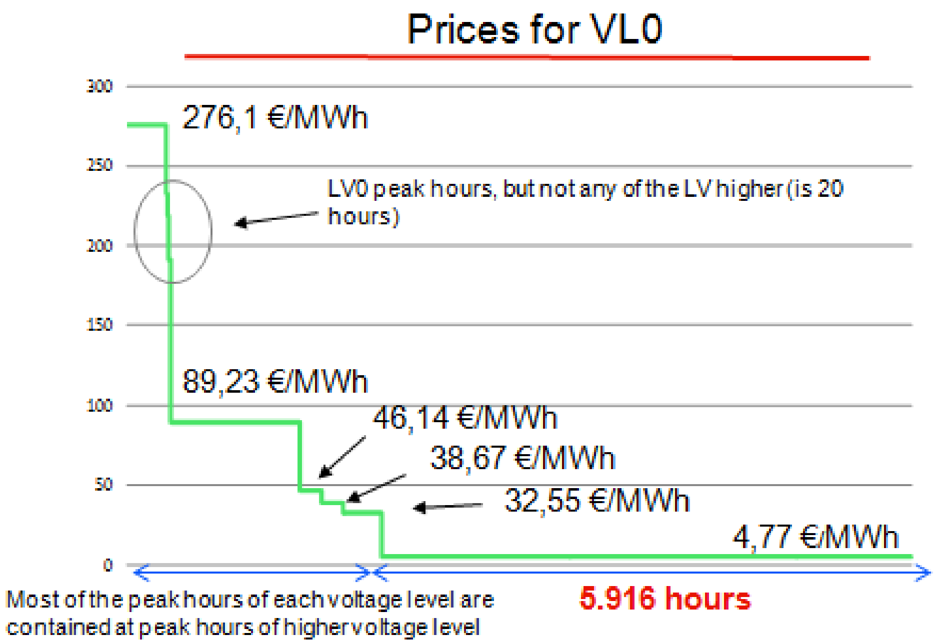
Energy circulated monotone curve ($\mathbf{D_{LV0}}$)

Network	Voltage level affected					Nº of peak hours	Prices of the peak hours in each VL (€/MWh)
VL0	D_{NT0}					487	186,75
VL1	D_{NT0}	D_{NT1}				1.880	39,93
VL2	D_{NT0}	D_{NT1}	D_{NT2}			2.130	6,78
VL3	D_{NT0}	D_{NT1}	D_{NT2}	D_{NT3}		2.378	5,48
VL4	D_{NT0}	D_{NT1}	D_{NT2}	D_{NT3}	D_{NT4}	2.823	24,5

Step 3: Determination of prices for network users

After computing peak hour prices in each voltage level, final prices for network users should be determined.

Prices for consumers in voltage level VL0:



During more than the half year hours, 5.916 in the VL0, the consumers will pay the floor price (explained in the calculation bases point) which is 4,77 €/MWh, the hours where VL0 consumers pays the VL4 peak hours(taking to VL0 multiplying by estimated losses in peak hours to rise from LV0 to LV4) sum to the floor price for VL0 peak hours have a 32,55 €/MWh price.

In the hours with 38,67 €/MWh price the consumer is paying the prices of LV4+ LV3 taken by losses factor to LV0 plus floor price for VL0 peak hours.

That way of obtaining prices will be used in each price, 276,1 €/MWh is the maximum price obtained with the following formula:

276,1 = 4,77 + 24,57 x (1+losses_$\mathbf{p_{04}}$)+ 5,48 x (1+ losses_$\mathbf{p_{03}}$)+ 6,78 x (1+losses_$\mathbf{p_{02}}$)+39,93 x (1+ losses_$\mathbf{p_{01}}$)+ 186,75

Where losses_$\mathrm{p_{04}}$ =13,05%: are the estimate losses in peak hours to rise VL0 to VL4

Where losses_$\mathrm{p_{03}}$= 11,65%: are the estimate losses in peak hours to rise VL0 to VL3

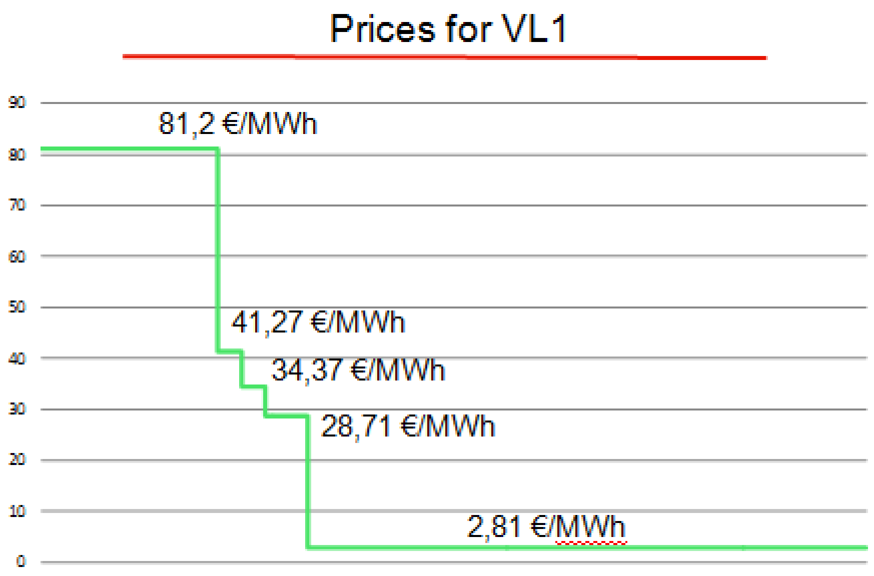
Where losses_$\mathrm{p_{02}}$= 10,11%: are the estimate losses in peak hours to raise VL0 to VL2

Where losses_$\mathrm{p_{01}}$= 8,1%: are the estimate losses in peak hours to raise VL0 to VL1

Most of the peak hours of each voltage level are contained in the peak hours of the upper level, because they are hours of maximum consumption for both levels.

But there are some exceptions, for example, the hours inside the circle will be the hours that are peak hours only from VL0, that occur for example en some Christmas days where the peak hours is produced when the families meet for dinner.

<u>Prices for consumers in voltage level VL1:</u>



The procedure will be the same as in the previous case more than the half of the hours will be paid with the floor prices (2,81 €/MWh) and the consumers will pay a higher prices as many voltage level peak hours coincided to the maximum price in VL1 where the consumer pays the price for peak hour of its own voltage level and the uppers with their corresponding losses taken to voltage level 1 as we observe in the following formula:

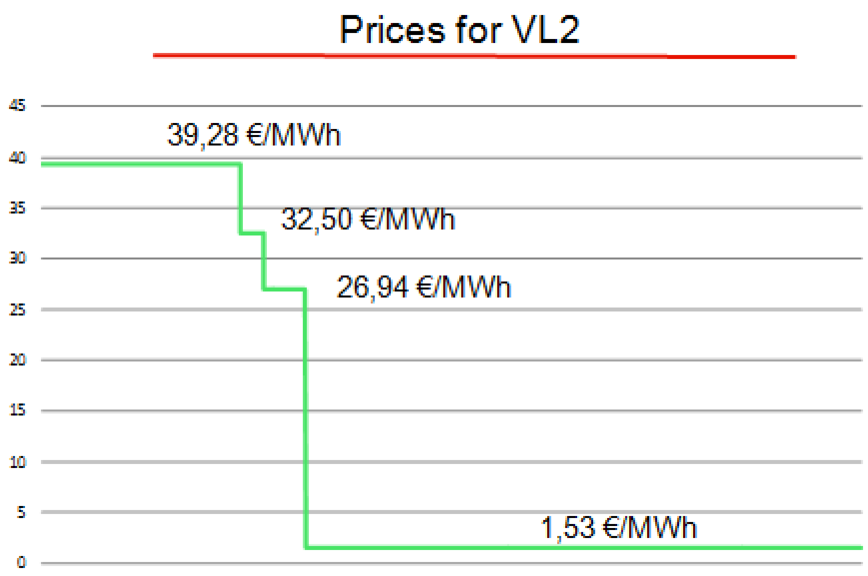
$$\mathbf{81{,}2 = 2{,}81 + 24{,}57\ x\ (1 + losses\_p_{14}\ ) + 5{,}48\ x(1 + losses\_p_{13}\ ) + 6{,}78\ x\ (1 + losses\_p_{12}\ ) + 39{,}93}$$

Where $losses\_p_{14}$ =5,43%: are the estimate losses in peak hours to rise VL1 to VL4

Where $losses\_p_{13}$= 3,20%: are the estimate losses in peak hours to rise VL1 to VL3

Where $losses\_p_{12}$= 1,81%: are the estimate losses in peak hours to rise VL1 to VL2

Prices for consumers in voltage level VL2:



The methodology and procedure to obtain the different prices is the same as the previous ones obtained, the maxim price for voltage level 2 will be obtained with the following formula:

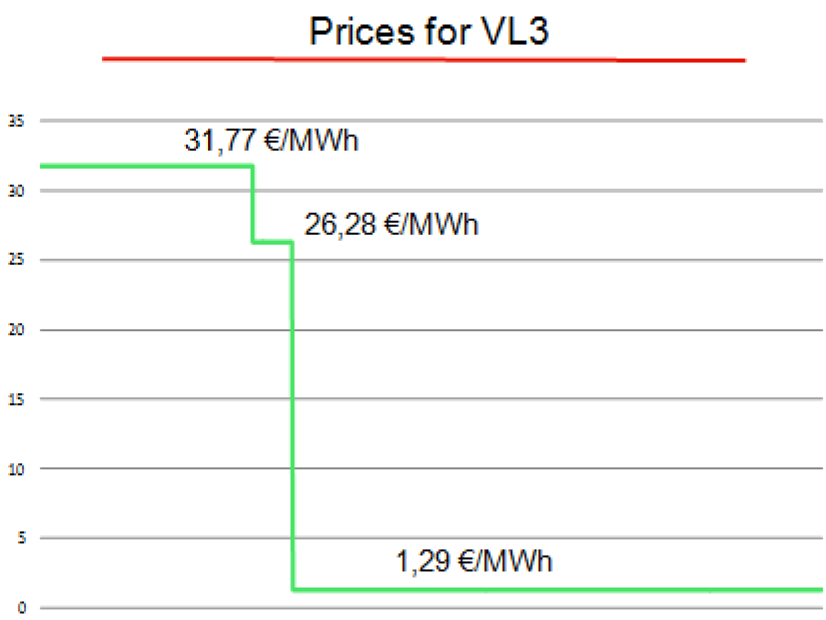
$$39{,}28 = 1{,}53 + 24{,}57 \text{ x } (1 + \text{losses\_p}_{24}) + 5{,}48 \text{ x } (1 + \text{losses\_p}_{23}) + 6{,}78$$

Where losses_p_{24} =3,27%: are the estimate losses in peak hours to rise VL2 to VL4

Where losses_p_{23}= 1,37%: are the estimate losses in peak hours to rise VL2 to VL3

The prices for floor hours will be 1,53 €/MWh , 26,94 €/MWh will be paying the hours of the peak hours of VL4 taken to VL2 with losses plus the floor price for VL2. 32,50 €/MWh is made of the peak hours of VL4 and VL3 taken to VL2 plus floor price. Finally 39,28 €/MWh is calculated by the sum of the peak hour price of VL2 plus 32,5 €/MWh.

Prices for consumers in voltage level VL3:

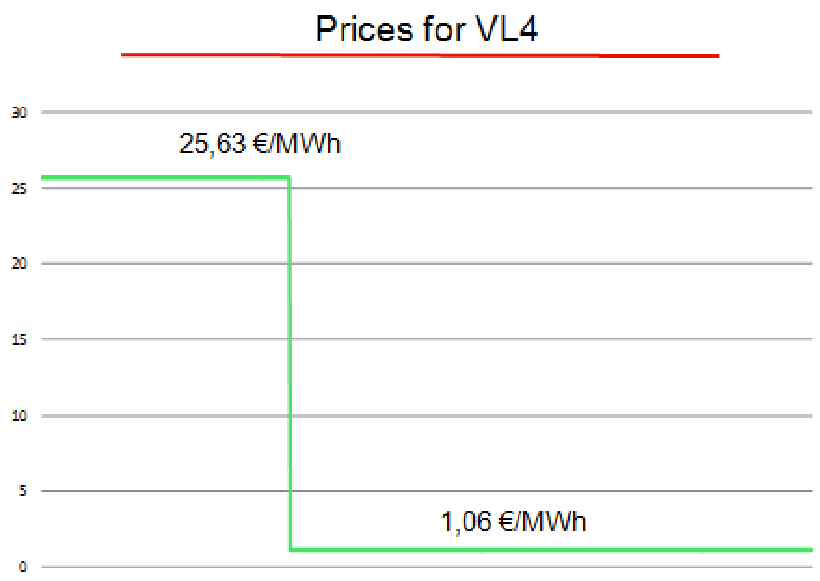


$$31{,}77 = 1{,}29 + 24{,}57 \text{ x } (1 + \text{losses\_p}_{34}) + 5{,}48$$

Where losses_p_{34} =1,71%: are the estimate losses in peak hours to rise VL3 to VL4.

Prices for consumers in voltage level VL4:

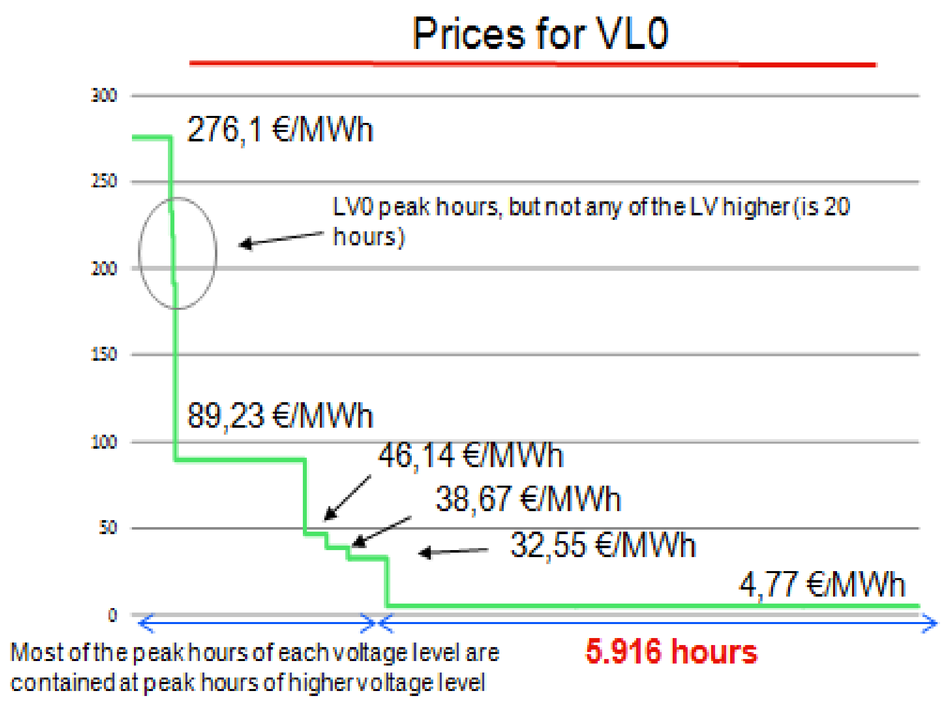
Finally for VL4, as it doesn't have upper levels, we will only have the floor price for VL4 and the price for VL4 peak hours plus the floor price.



5.3. Sensitivity analysis

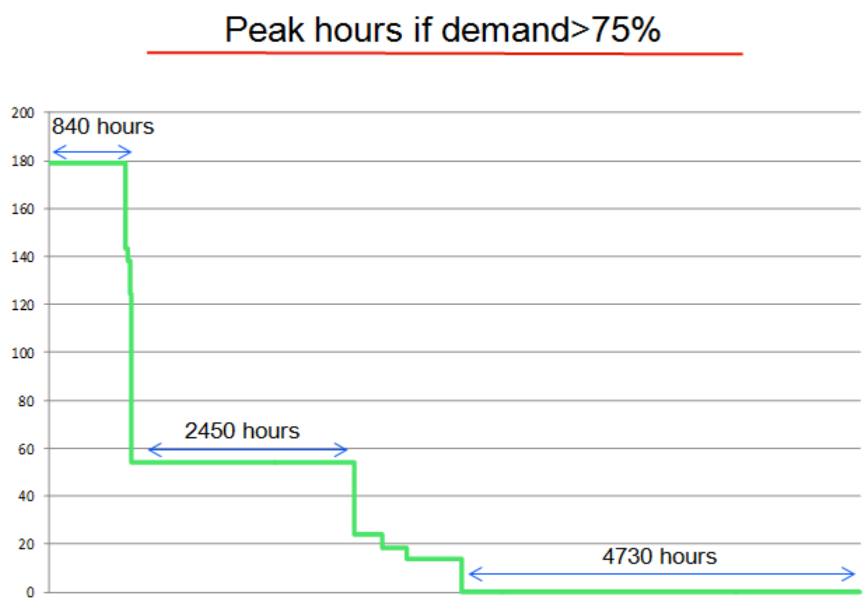
In our methodology we settled in 80% of the maximum demand the distinction between peak and off-peak hours (being the hour with demand higher than that 80% the ones in charge to pay the peak prices).

The 80% is an assumption, we decided to choose that percentage because it was the percentage that gave us better results for our objective, giving a reduced number of hours of maximum peak demand at a price lower than 300 €/MWh (that is not an exorbitant price) and more than the half of the yearly hours with floor cost (5.916 hours).



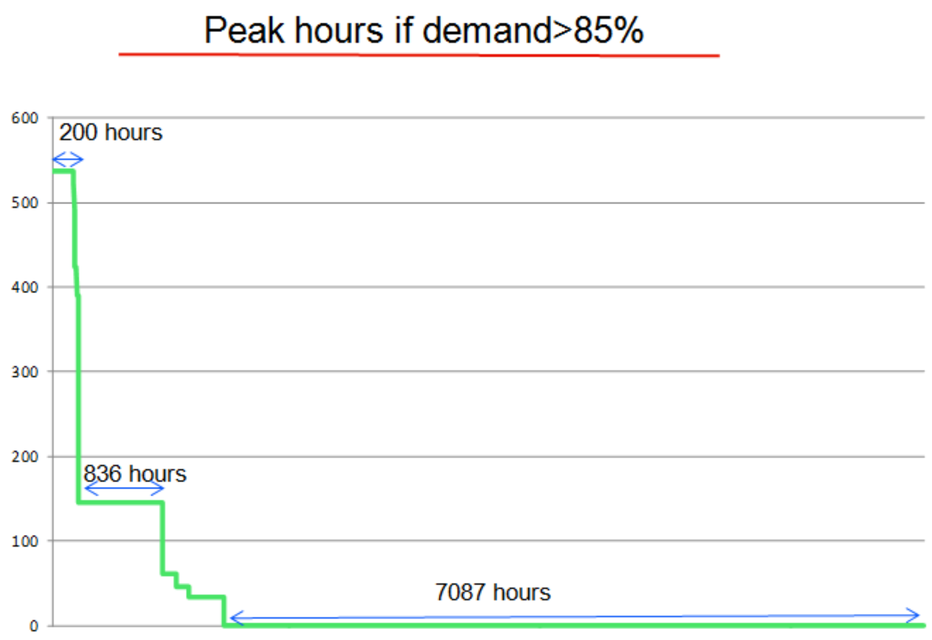
But as that is an assumption we were not sure if we could reach better results with other percentages.

That the reason why we tried another percentages to verify that 80% was the best option. With 75% we observe that:



Although the price of peak hours is much lower, there will be much more peak hours and less floor hours, which won't give the necessary efficient signals to the consumers.

With 85%, the graphic shows:



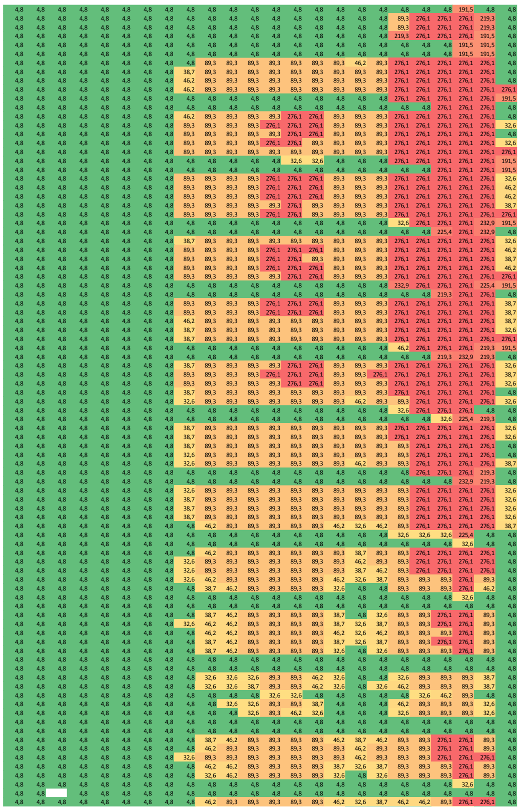
That gives us not adequate result because although there are only 200 hours of peak demand, those hours have an enormous price.

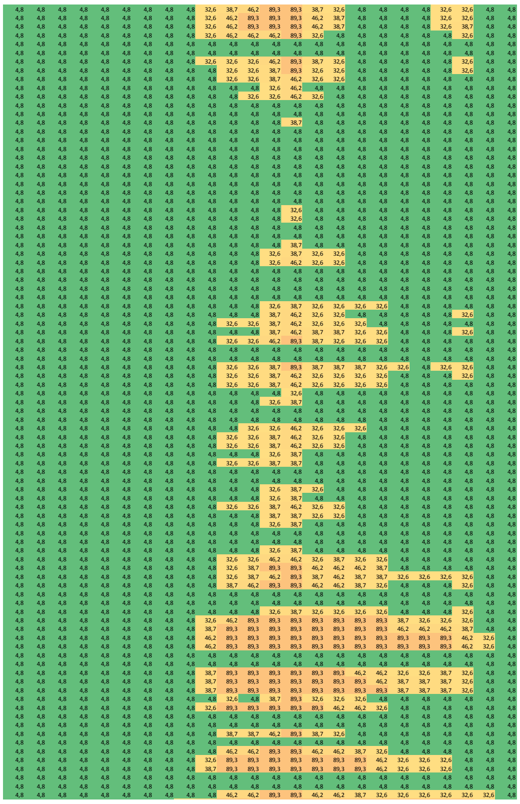
5.4. Hourly cost of network acces tariff

The table below shows in code colors how the distribution of prices is along the year 2014, for consumers in low voltage level.

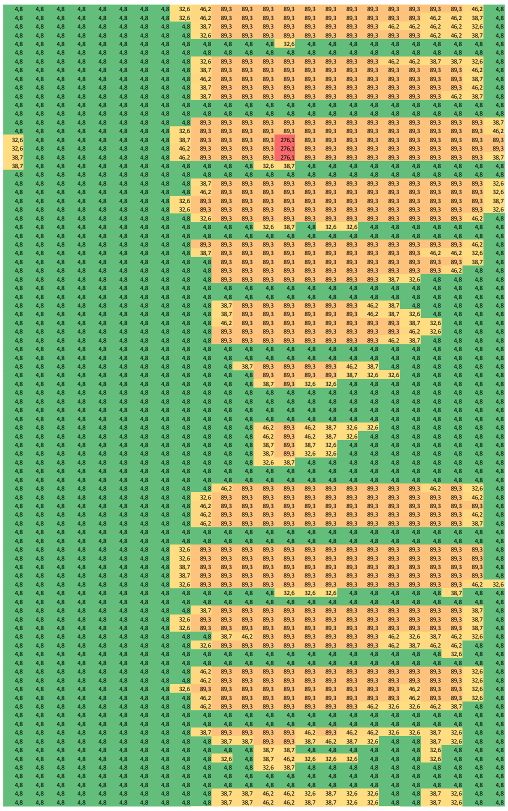
Peak hours for demand LV0

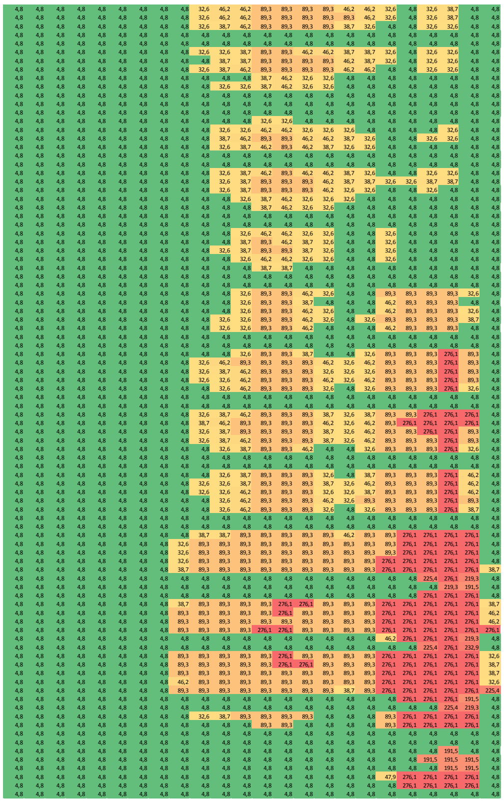
First semester





Second semester





276,10 €/MWh	< 276,10 €/MWh y > 89,23 €/MWh	89,23€/MWh	32,6 €/MWh 38,7 €/MWh 46,2 €/MWh	4,77 €/MWh

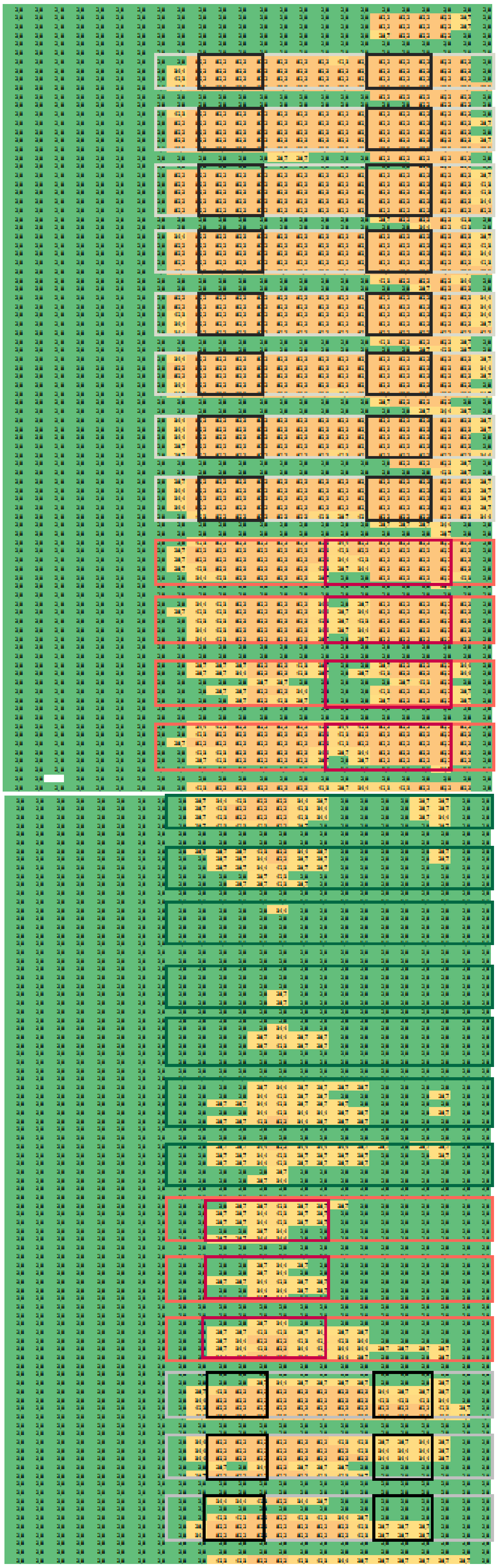
The peak prices (red) will be located in winter months, the hours with maximum demand will be from 19 to 23 hours in the week days due to that are the hours where people is at home and heating is on. In 2014 there is not a lot of hours of peak demand in summer, because 2014 wasn't a hot summer but it is possible that years as 2015 (which was the hottest of the last decades) there would be some peak hours at noon hours because consumption from air conditioner.

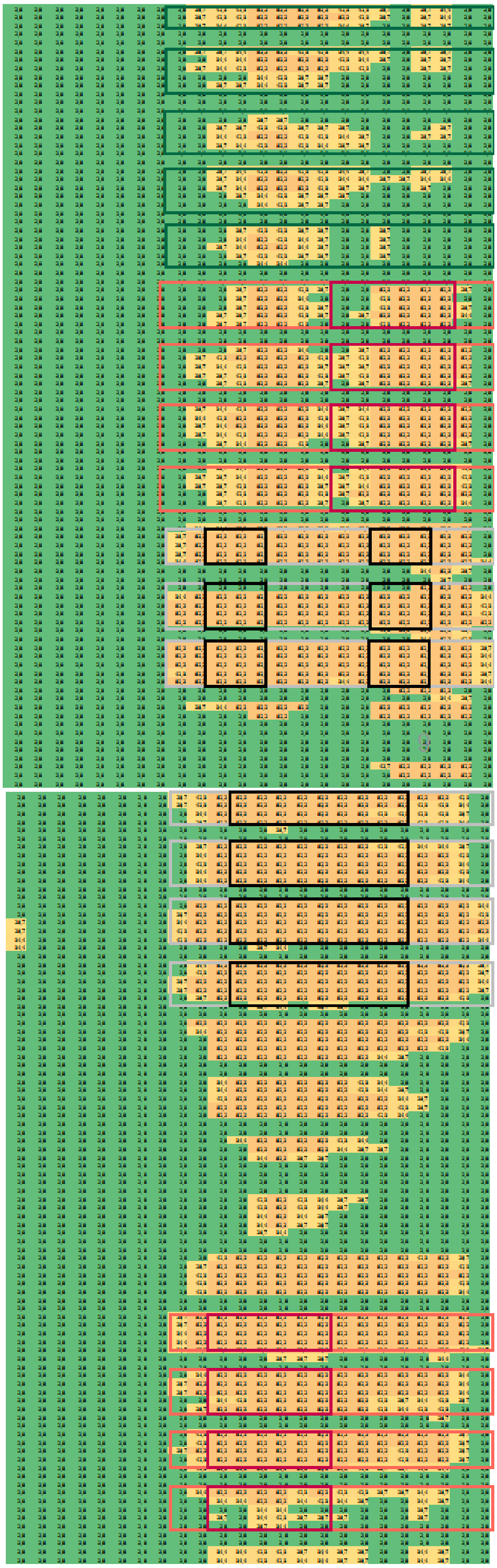
Other interesting information that we get from that table is that in spring and autumn months most of the hours are floor prices.

Now we can see the distribution of prices for VL0 and its comparison with current the periods.

First semester

Second semester





In higher voltage levels which have 6 periods we can appreciate where the different periods are placed .We are comparing it with the actual prices.

For example in VL1:

- Period 1: in black, is located in the peak hours in the summer and winter months where there is maximum demand.
    - There are 591 hours of period 1.
- Period 2: in grey, located in the same months that period 1, from 8 am to 24 within period 1 hour. There are 836 hours of period 2.
- Period 3: in red, peak hours of spring and autumn months.
    - There are 468 hours of period 3.
- Period 4: in orange, located in the same months that period 3, from 8 am to 24 within period 3 hours.
    - There are 790 hours of period 4.
- Period 5: in green, located in October, April and May, months with lower demand. The range where is located is between 8 and 24 hours.
    - There are 912 hours of period 5.
- The rest of the hours are period 6 that belong to the floor prices.
    - There are 5.161 hours of period 6.

5.5. Price comparison for network tariffs

The proposed methodology is compared with the current situation and the possibility that charges are taken out from the tariff and CNMC methodology will be applied to the network costs.

The comparison of the price monotones of the network tariffs and the weighted average prices of each tariff is shown in the following graphics.

First of all we are going to explain each of the elements that compose each methodology that we are going to compare:

- Proposed methodology: is the methodology explained in this thesis allocation cost in periods of maximum demand and considering that charges are removed from electricity.
- The current scenario: that is, the tariff those consumers see in their bills at present. Comparison is made between only with the energy term and including the capacity term variabilized (as average power consumption rate).

Capacity payments consist, according to Red Eléctrica de Spain (REE) in a regulated payment service to finance power capacity medium and long term returns offered by generation facilities to the electricity system. This concept is regulated included in the energy term, the price you pay per kWh you consume.

The energy term price per kWh for each tariff and period are taken from the “ORDEN IET/107/2014” and are shown in the following table:

	Consumer category		Energy term (Euros/kWh)					
			P1	P2	P3	P4	P5	P6
LV	2.0 A (Pc<= 10kW)	2.0 A	0,044027					
	2.0 DHA (Pc<= 10kW)	2.0 DHA	0,062012	0,002215				
	2.0 DHS (Pc<= 10kW)	2.0 DHS	0,062012	0,002879	0,000886			
	2.1 A (10<Pc<= 15kW)	2.1 A	0,05736					
	2.1 DHA (10<Pc<= 15kW)	2.1 DHA	0,074568	0,013192				
	2.1 DHS (10<Pc<= 15kW)	2.1 DHS	0,074568	0,017809	0,006596			
	3.0 A (Pc>15 kW)	3.0 A	0,018762	0,012575	0,00467			
MV	3.1 A (Pc<=450 kW)	3.1 A	0,014335	0,012754	0,007805			
	6.1A (Pc>450KW)	6.1A	0,026674	0,019921	0,010615	0,005283	0,003411	0,002137
	6.1B (Pc>450KW)	6.1B	0,023381	0,017462	0,009306	0,004631	0,00299	0,001871
HV	6.2	6.2	0,015587	0,011641	0,006204	0,003087	0,001993	0,001247
	6.3	6.3	0,015048	0,011237	0,005987	0,002979	0,001924	0,001206
	6.4	6.4	0,008465	0,007022	0,004025	0,002285	0,001475	0,001018

The power term variabilized:

			Power term variabilized (Euros/MWh)					
	TARIFFS		P1	P2	P3	P4	P5	P6
LV	2.0 A (Pc ≤ 10 kW)	2.0 A	69,05					
	2.0 DHA (Pc ≤ 10 kW)	2.0 DHA	103,89	103,89				
	2.0 DHS (Pc ≤ 10 kW)	2.0 DHS	59,14					
	2.1 A (10< Pc ≤ 15 kW)	2.1 A	66,65					
	2.1 DHA (10< Pc ≤ 15 kW)	2.1 DHA	92,09	92,09				
	2.1 DHS (10< Pc ≤ 15 kW)	2.1 DHS	109,54					
	3.0 A (Pc > 15 kW)	3.0 A	120,39	27,41	41,71			
MV	3.1 A (1 kV a 36 kV)	3.1 A	111,21	38,13	9,93			
	6.1A (1 kV a 30 kV)	6.1A	94,64	37,71	52,28	32,54	23,52	4,34
	6.1B (30 kV a 36 kV)	6.1B	66,85	27,98	38,71	23,98	16,87	3,59
HV	6.2 (36 kV a 72,5 kV)	6.2	49,06	18,39	26,92	16,28	11,30	1,62
	6.3 (72,5 kV a 145 kV)	6.3	44,50	16,88	24,07	14,36	9,87	1,14
	6.4 (Mayor o igual a 145 kV)	6.4	31,61	11,47	17,07	10,18	6,87	0,76

- <u>CNMC scenario</u>: In the CNMC scenario as in our proposed methodology charges are removed from the energy term.

  In fact, CNMC methodology gives more importance to the power term. We will compare two cases with the new methodology:

- Only the energy term, according to CNMC methodology. Represented in pink.

Acces tariff(eur/kWh)		Hourly period					
tariff group		P1	P2	P3	P4	P5	P6
2.0 A (Pc ≤ 15 kW)	2.0 A	0,00688					
2.0 DHA (Pc ≤ 10 kW)	2.0 DHA	0,00918	0,00319				
2.0 DHS (Pc ≤ 15 kW)	2.0 DHS	0,00759	0,00519	0,0008			
2.1 A (10< Pc ≤ 15 kW)	2.1 A	0,00688					
2.1 DHA (10< Pc ≤ 15 kW)	2.1 DHA	0,00918	0,00319				
3.0 A (Pc > 15 kW)	3.0 A	0,00994	0,00793	0,0008			
3.1 A (1 kV a 36 kV)	3.1 A	0,02387	0,01482	0,00993	0,00266	0,00004	0,00073
6.1A (1 kV a 30 kV)	6.1A	0,02387	0,01482	0,00993	0,00266	0,00004	0,00073
6.1B (30 kV a 36 kV)	6.1B	0,02387	0,01482	0,00993	0,00266	0,00004	0,00073
6.2 (36 kV a 72,5 kV)	6.2	0,01426	0,00806	0,00553	0,00148	0,0002	0,00033
6.3 (72,5 kV a 145 kV)	6.3	0,00983	0,00584	0,00418	0,00111	0,00002	0,00024
6.4 (>145 kV)	6.4	0,01164	0,00735	0,00493	0,00152	0,00002	0,00029

- Term energy and capacity charges, according to the methodology CNMC variabilized (as average power consumption rate). Represented in red.

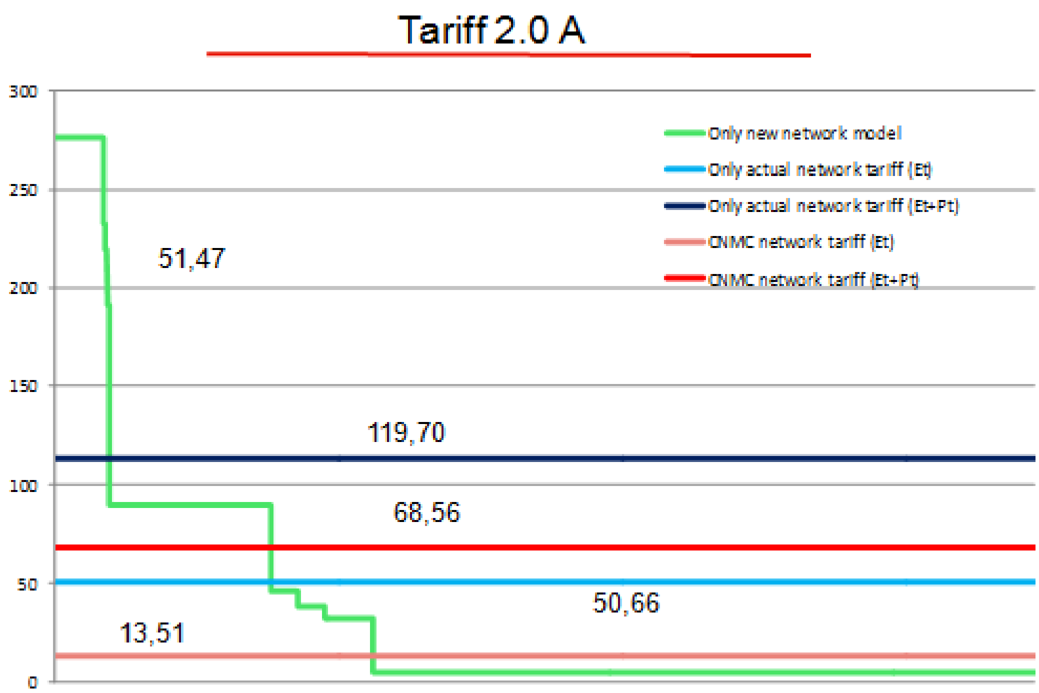
Acces tariff(eur/kWh)		Hourly period					
tariff group		P1	P2	P3	P4	P5	P6
2.0 A (Pc ≤ 15 kW)	2.0 A	55,05					
2.0 DHA (Pc ≤ 10 kW)	2.0 DHA	82,83	82,83				
2.0 DHS (Pc ≤ 15 kW)	2.0 DHS	47,15					
2.1 A (10< Pc ≤ 15 kW)	2.1 A	45,48					
2.1 DHA (10< Pc ≤ 15 kW)	2.1 DHA	62,84	62,84				
3.0 A (Pc > 15 kW)	3.0 A	26,87	21,48	5,43			
3.1 A (1 kV a 36 kV)	3.1 A	96,13	52,98	40,72	21,04	0,32	2,18
6.1A (1 kV a 30 kV)	6.1A	50,63	27,19	19,40	9,99	0,15	1,63
6.1B (30 kV a 36 kV)	6.1B	45,13	25,45	18,13	9,29	0,13	1,70
6.2 (36 kV a 72,5 kV)	6.2	33,78	18,72	14,46	4,21	0,06	0,61
6.3 (72,5 kV a 145 kV)	6.3	24,02	13,36	11,26	3,23	0,04	0,50
6.4 (>145 kV)	6.4	29,59	17,56	13,80	3,95	0,04	0,56
total cost=5591293 m€							

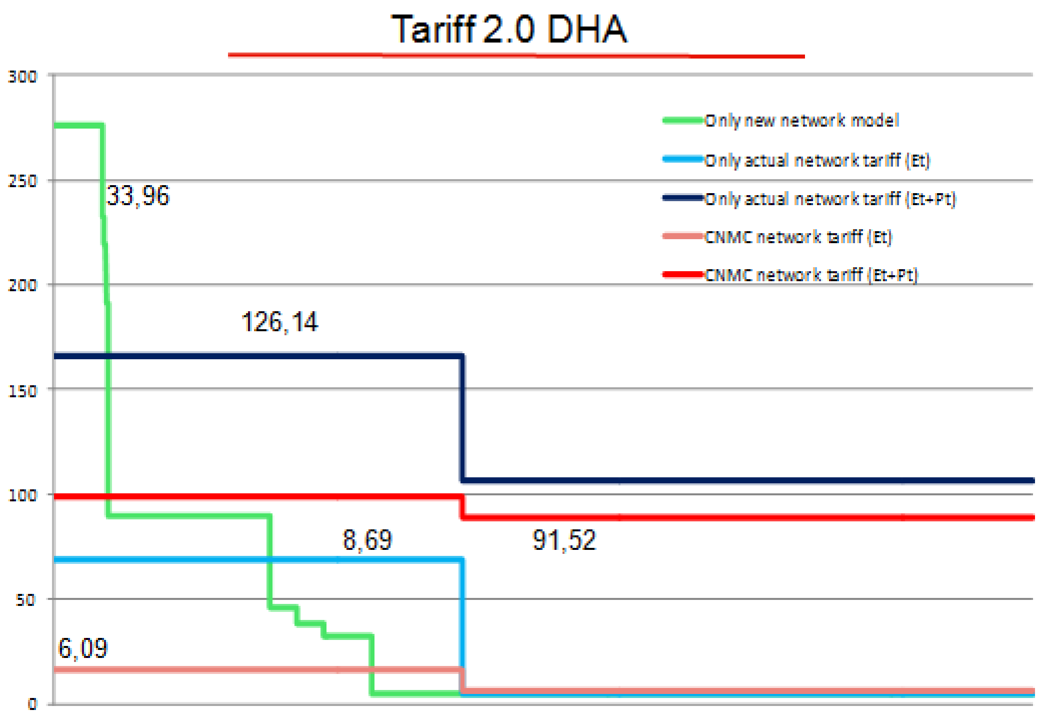
When we compare the new methodology with the current methodology, as we are removing the charges from the electric tariff, most of the clients are getting benefits.

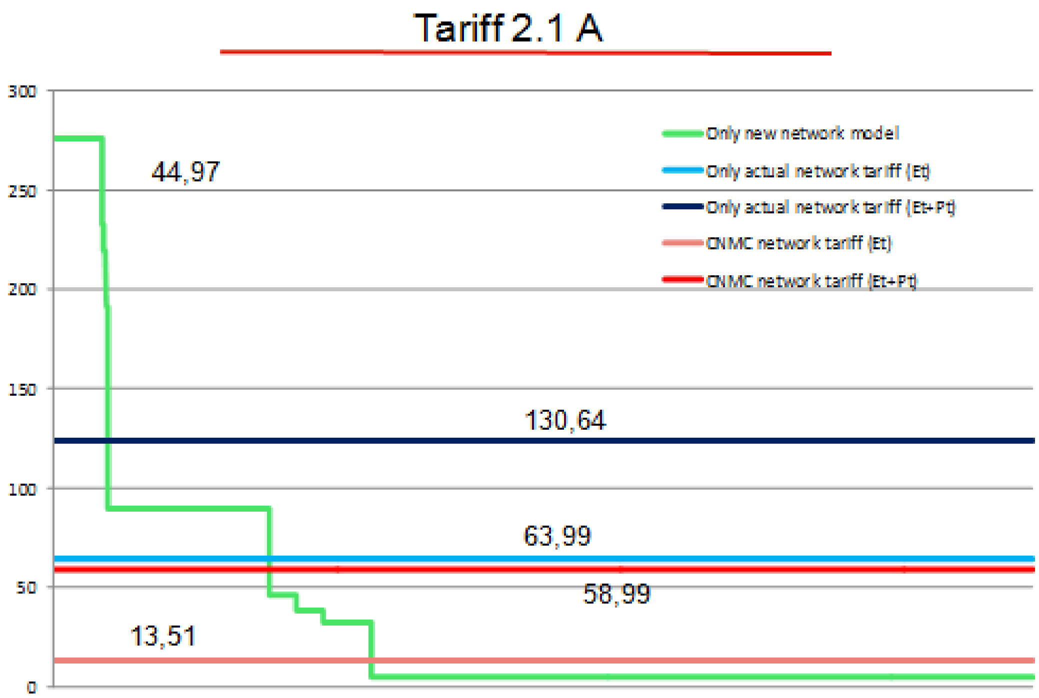
But if we compare with the CNMC methodology as the quantity collected is the same there will be winners and losers.

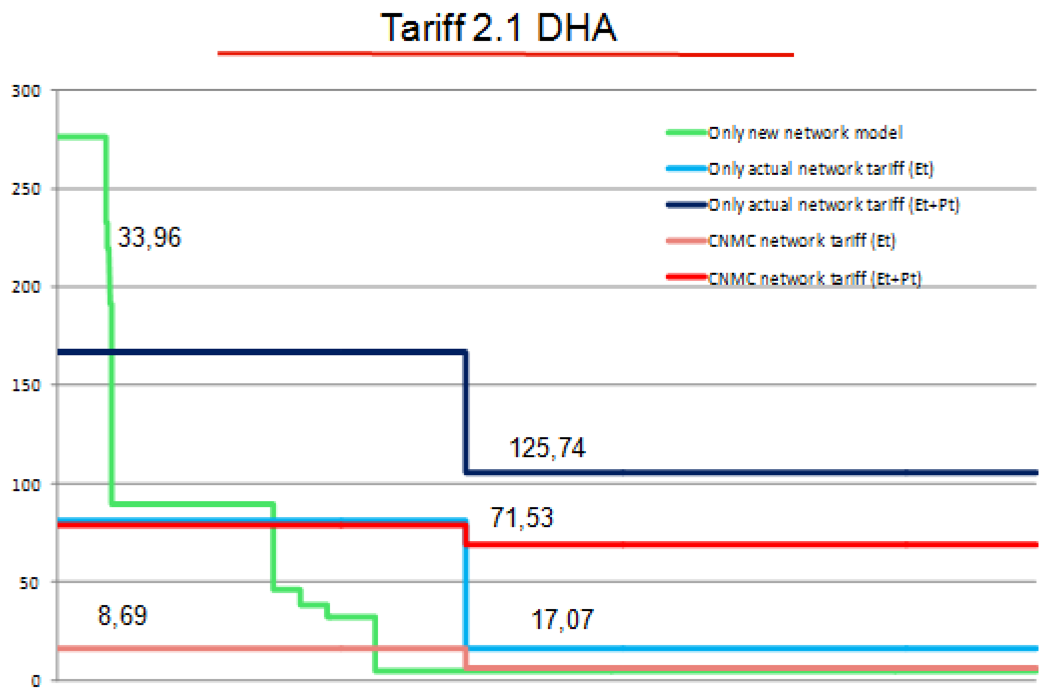
The following graphics represent the comparison of prices for each methodology for the same tariff.

Graphs below show the monotones for the scenarios described.




Tariff 2.0 DHA
300
250
200
150
100
50
0
Only new network model
Only actual network tariff (Et)
Only actual network tariff (Et+Pt)
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)
33,96
126,14
8,69
91,52
6,09


Tariff 2.1 A
300
250
200
150
100
50
0
Only new network model
Only actual network tariff (Et)
Only actual network tariff (Et+Pt)
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)
44,97
130,64
63,99
58,99
13,51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300
250
200
150
100
50
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Only new network model
Only actual network tariff (Et)
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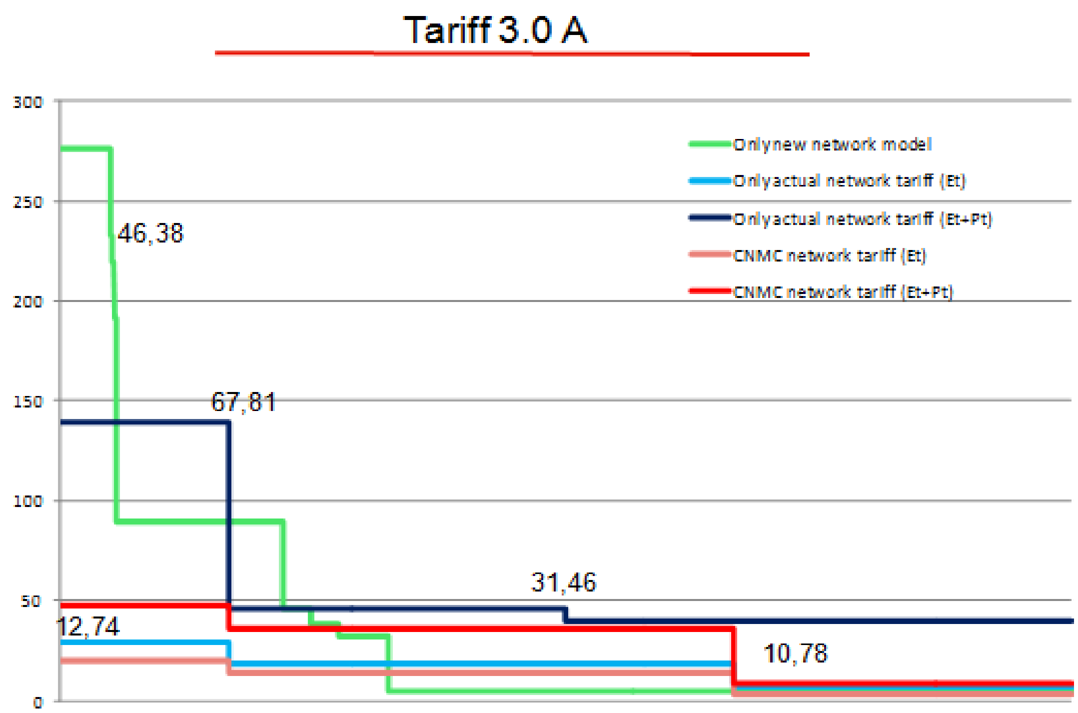
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)
33,96
125,74
71,53
8,69
17,07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200
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100
50
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CNMC network tariff (Et+Pt)
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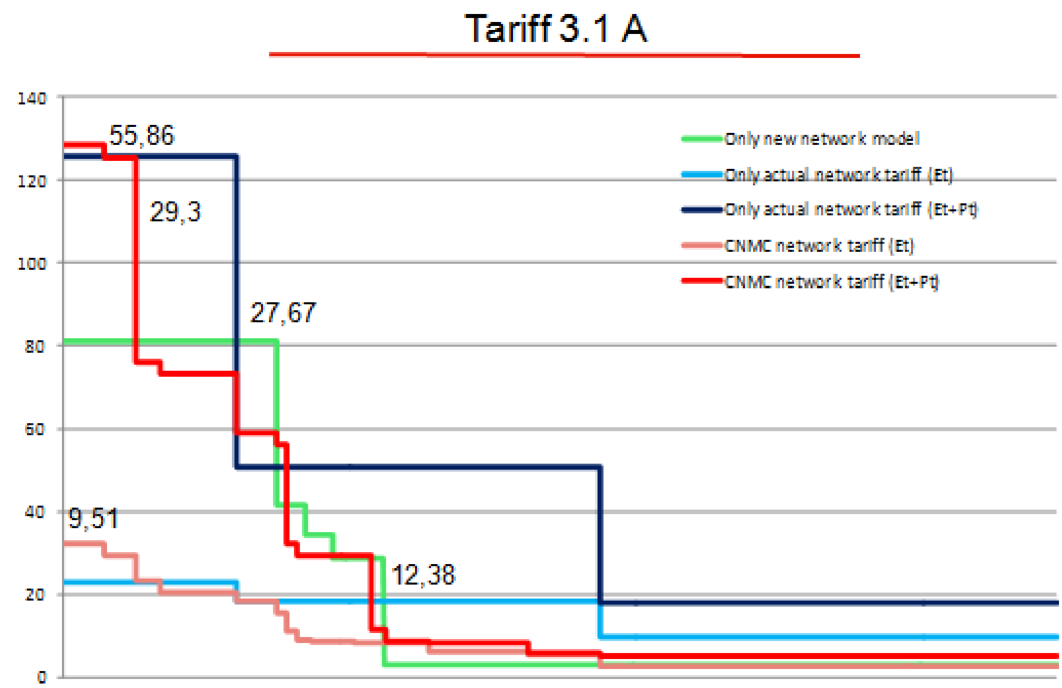
67,81
31,46
12,74
10,78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140
120
100
80
60
40
20
0
55,86
29,3
27,67
9,51
12,38
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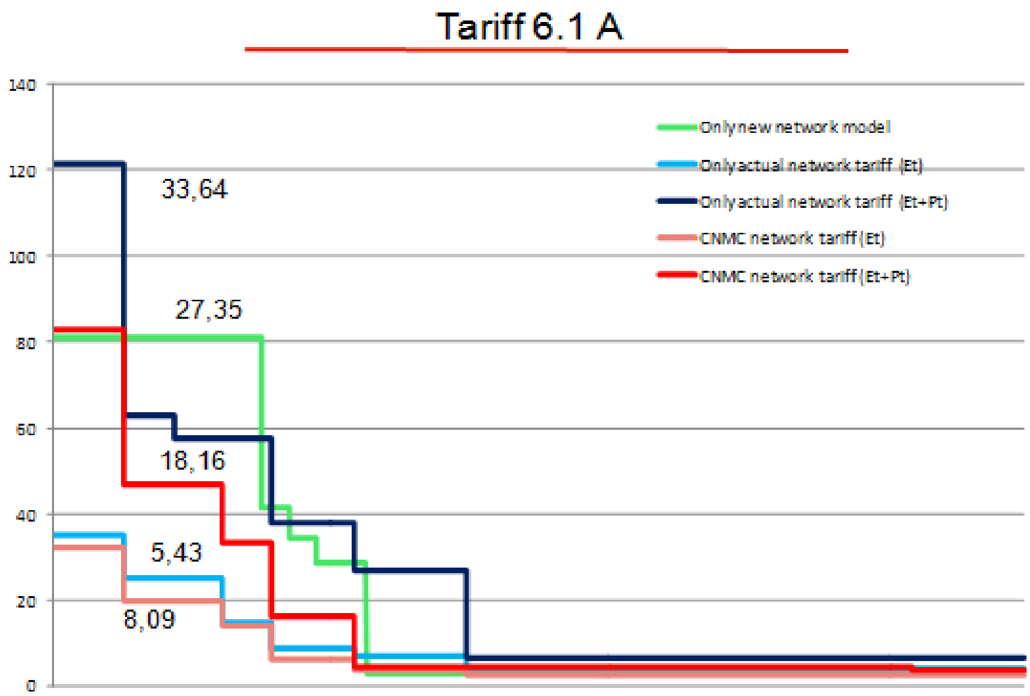
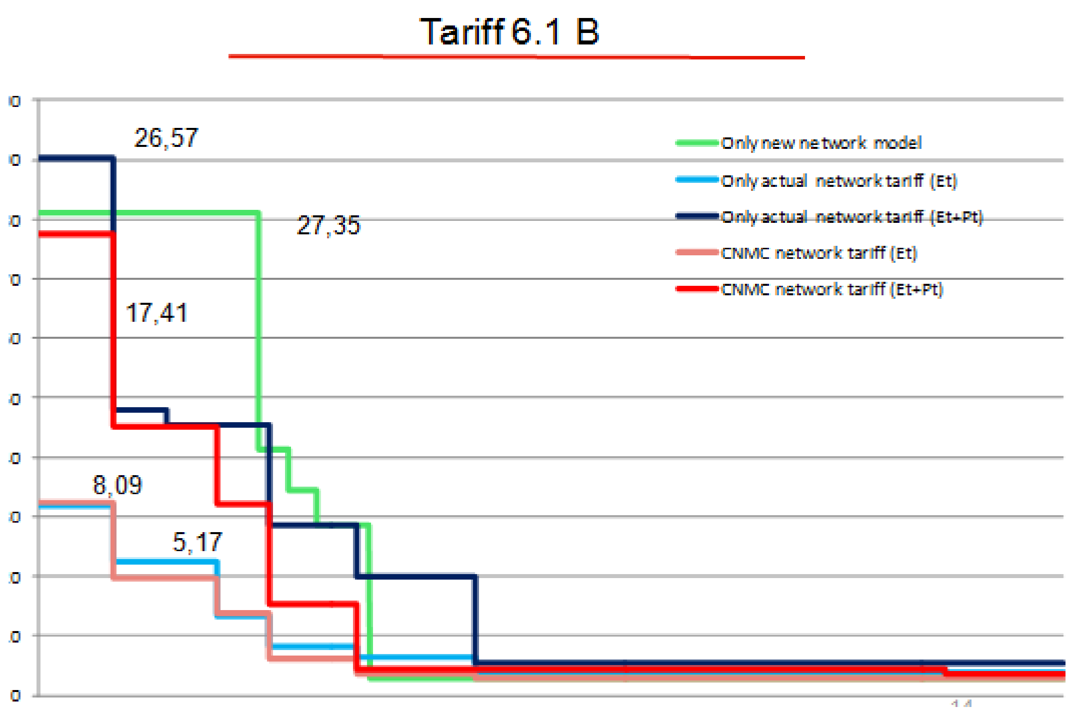
Only actual network tariff (Et+Pt)
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)


Tariff 6.1 A
140
120
100
80
60
40
20
0
33,64
27,35
18,16
5,43
8,09
Only new network model
Only actual network tariff (Et)
Only actual network tariff (Et+Pt)
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)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26,57
27,35
17,41
8,09
5,17
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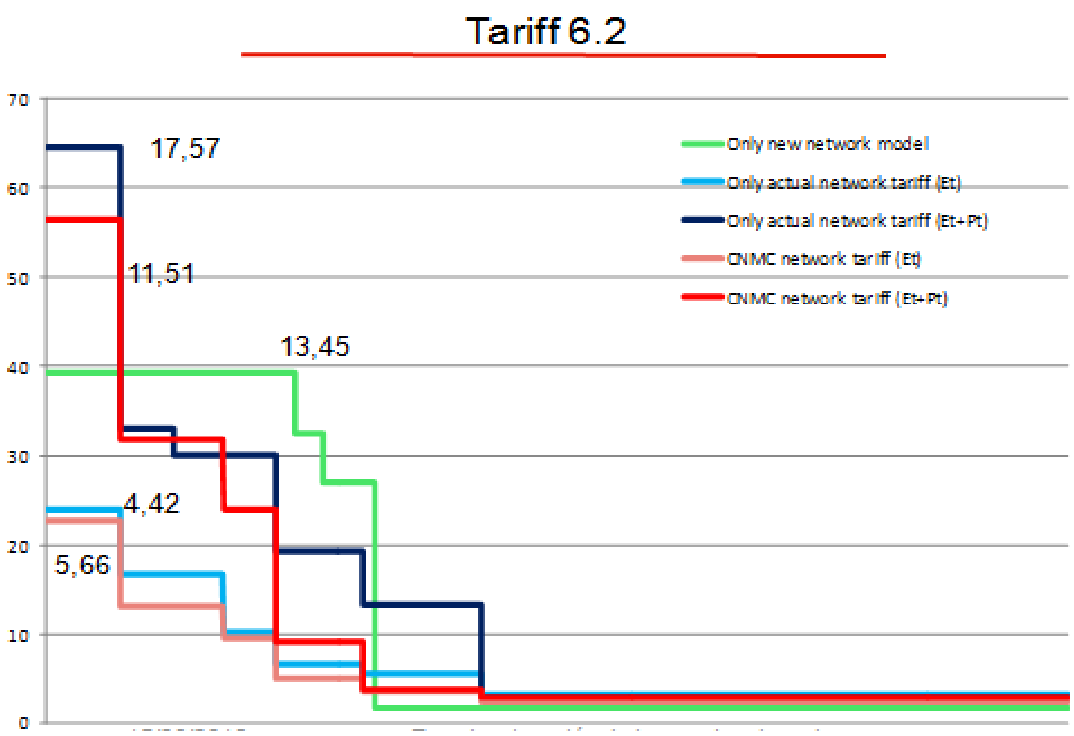
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)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70
60
50
40
30
20
10
0
17,57
11,51
13,45
4,42
5,66
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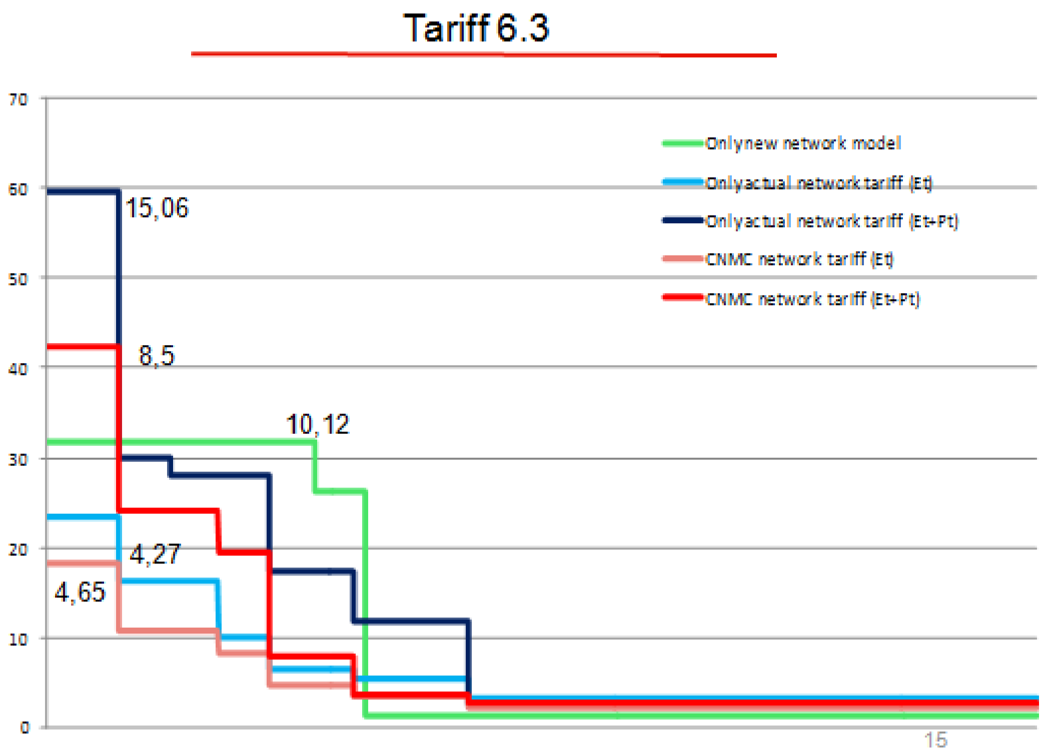
Only actual network tariff (Et+Pt)
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)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70
60
50
40
30
20
10
0
15
Only new network model
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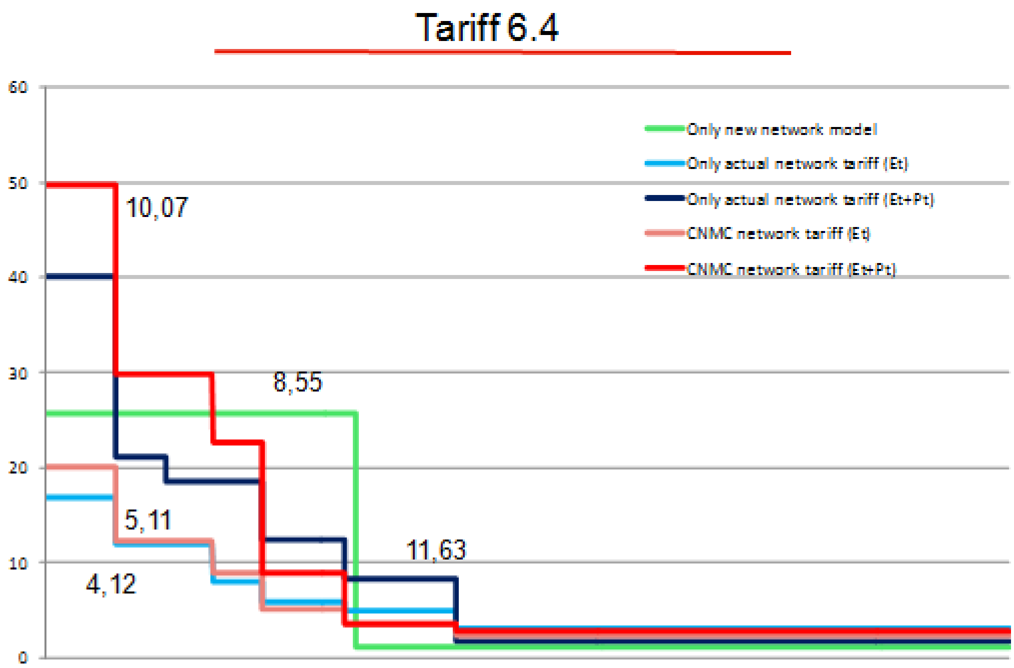
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)
15,06
8,5
10,12
4,27
4,65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50
40
30
20
10
0
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Only actual network tariff (Et+Pt)
CNMC network tariff (Et)
CNMC network tariff (Et+Pt)
10,07
8,55
5,11
11,63
4,12

In the following table we observe a comparative of the average prices, according to the standard profile of consume.

	Only new network model	Only actual network tariff (Et)+CapP+ Int	Only actual network tariff (Et+Pt)+ CapP+Int	CNMC network tariff (Et)+CapP+ Int	CNMC network tariff (Et+Pt)+ CapP+Int	Change over to the new model	
						Only actual network tariff (Et+Pt)+ CapP+ Int	CNMC network tariff (Et+Pt)+ CapP+ Int
2.0 A	51,47	50,66	119,70	13,51	68,56	-57,00%	-24,92%
2.0 DHA	33,96	6,09	126,14	8,69	91,52	-73,07%	-62,89%
2.1 A	44,97	63,99	130,64	13,51	58,99	-65,57%	-23,76%
2.1 DHA	33,96	17,07	125,74	8,69	71,53	-72,99%	-52,51%
3.0 A	46,38	10,78	67,81	12,74	31,46	-31,59%	47,44%
3.1 A	27,67	12,38	55,86	9,51	29,30	-50,47%	-5,56%
6.1A	27,35	5,43	33,64	8,09	18,16	-18,69%	50,59%
6.1B	27,35	5,17	26,57	8,09	17,41	2,94%	57,08%
6.2	13,45	4,42	17,57	5,66	11,51	-23,43%	16,88%
6.3	10,12	4,27	15,06	4,65	8,50	-32,78%	19,10%
6.4	8,55	4,12	11,63	5,11	10,07	-26,52%	-15,10%

With the new network model we have a decrease in the prices of all tariffs with the exception of the 6.1B.

The utilization hours in VL0 will be for the new methodology in the normal values.

The impact of the new methodology in the numbers of periods will be significant:

- For VL0 goes from 3 periods with a uniform peak of four hours that only change from winter (in the afternoon) to summer (in the morning) to six periods.
- In the 3.1 goes from 3 periods with a uniform peak of six hours that only change from winter (in the afternoon) to summer (in the morning) to five periods.
- For 6.1 A and B goes from six periods with seasonal changes, to 5 periods.
- For voltage levels 2, 3 and 4 goes from 6 periods with seasonal changes to 4,3 or 2 periods.
- The cost-benefit analysis is not as clear for industrial customers, in which:

- The new tariffs can mean a change in current shifts, in cases where these are organized according to the current tariff periods

- The benefit is less, as from rates that do not pose the problems described

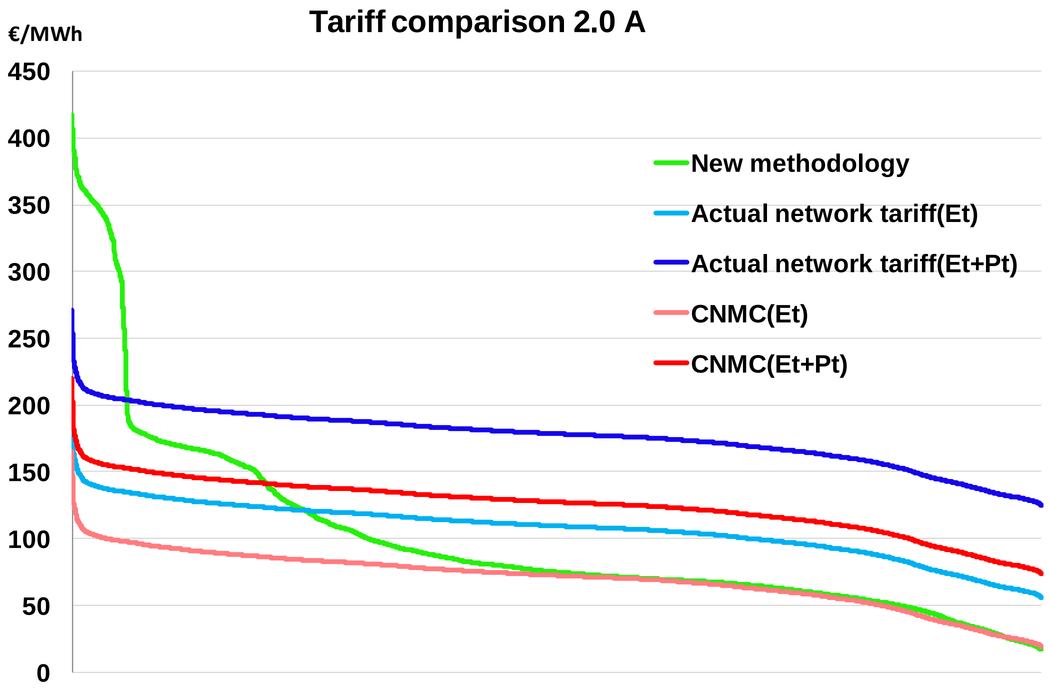
To sum up for low voltage clients the number of periods will increase but for the rest will be reduced.

Now we are going to include some extra components that must be paid in the tariffs that will affect to the tariffs explained before and including that energy cost parameters we will get the final consumer bill.

- Daily market prices and adjustment services 2014
- Capacity payments set for 2016
- 2015 interrumpibility costs for each month
- Standard rate losses

Now as in the previous block we compared each tariff one by one, and decide if our new methodology is better than the actual and CNMC.

We took as example the 2.0 A that is the more significant, because is where higher saving are observed.



For low voltage tariffs as the 2.0 A the new methodology is much favorable than the actual methodology and the CNMC both with energy term and power term.

There will be clients that will pay a really high price but it will only happened for some client that will be consuming in the peak hours of winter or summer, but for most of the consumers they will pay a price really much lower than with the other tariffs, shaving money if they do an efficient use of the electricity.

When it goes to upper levels the difference is lower not having such big price differences.

5.6. Results of the new methodology

With the implementation of the new methodology the following benefits are achieved:

- The new tariff reflect the real cost of the electricity consumption: the peak consumption will include the energy cost, more generation power and network (transmission and distribution) and the off-peak consume will include only the generation cost.

- Clear price signal to the consumer: as the previous graphics show there will be a lot of hours with a very low energy price (diary market + losses), as a consequence consumers must try to consume in those hours.
  In the other hand there will be only a few hour with high price where consumers should avoid to consume.

- Electrification: one of the most important consequences of the new methodology is the increase of the electrification in off-peak hours where the energy price is too low and the network access tariff is low.

- Demand management: consume in hours with low demand has an incentive.

  Doubt to the distribution generation, domestic consumers are able to use batteries, then they can charge then in off-peak hours being able to use it when there are peak hours.

  This will create changes in the monotone and the prices.

- Groups: The cost of a client group is the same as the sum of the each customer costs.

5.7. Implementation

Firstly, there is a geographical analysis that the CNMC must carry out:

- Differentiation between geographical zones must be done for low voltage by consumption behavior(for example distinguishing between cost area and non cost areas because in cost area there will be a different behavior having low demand on winter and a really high demand on summer season) and what would be the methodology for allocating distribution costs between different areas.

  This will result in different tariff periods for low voltage, with different prices.

- For insular systems, an analysis of the load curve in MV and HV levels should also be made in order to decide if peak periods in MV and HV have to be reconsidered.

The necessary steps to implement the new network prices would be:

- Red Eléctrica would estimate the demand for the next year, by voltage level and geographical zone established by the CNMC and subtracting the distribution generation estimated in each voltage level.
- Then the CNMC will establish peak hours and their prices by voltage level and geographic area, and will publish them.
- Red Eléctrica will revise the demand estimation in a monthly or daily basis.
- Finally, the CNMC will recalculate prices with the revenue estimation of network tariffs from previous months, from real demand, the recalculation of the prices (from income needs and demands estimation) and posting the prices (just like in PVPC).

Retailers will have two options:

- Passing-through network tariff prices to customers
- Elaborating simpler offers after an analysis of the corresponding profiles and associated risks.

5.8. Distributed Generation

EU Directive 2009/72/EC defines distributed generation as generation plants connected to the distribution system.

The framework proposes allocation of fixed network cost according network profiles. A profile encapsulates all the information necessary to determine each grid user's contribution to the network cost.

Grid users become more sophisticated by introducing distributed generation, DR, load control and energy management systems, storage, and new loads such electric vehicles, so it is not longer possible keep using existing clients classification.

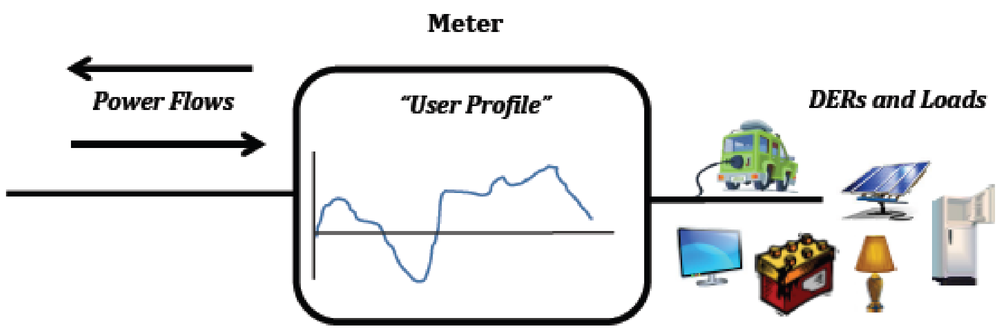
Moreover, network users' activities behind the electricity meter often are – and ought to remain as far as possible– a black box to distribution utilities (see Figure 1 below).

Consumer should pay the cost to the network that they are using, so if you have DG which is providing you energy you don't have to pay for it, only the part that you take from the network. In the same case, they should be paid if they poor to the network.

To avoid discriminatory tariff, the calculation of the use charges of the distribution system must be correlated to the particular use activities of the network.

Building user profiles based on cost drivers, and assigning charges for users according to those profiles avoids the challenges associated with having to identify network users' specific uses of electricity.

Rather, profiles permit a distribution utility to quantify grid users' contributions to network costs without requiring detailed knowledge of which network users in a distribution utility's service area own and charge EVs, operate battery storage units, or utilize solar panels, micro-cogeneration units, or backup diesel generators.



This framework is neutral to the particular technologies employed behind a network user's meter and the level of aggregation of multiple distributed energy resources at a point of network connection, and it is suitable for the distribution network component of the regulated electricity access charge under any regulatory framework.

For domestic consumer, with the actual methodology the distributed generation users are saving the variable term (its 44€/MWh) plus the energy price in the market.

With our new proposed methodology, distributed generation users will safe 42,47 €/MWh (which is the average price for photovoltaic).

The distribution generation installation will lead to the implementation of a zonal and dynamic model, because as is explained some areas could have different demand behaviors as the cost zones that have their peak demand in the summer season.

The demand curve will be affected by the distributed, decreasing the price for the hours where distributed generation is used and provoking changes in the curve and in the peak hours.

The same situation will occur whit the batteries, if the implementation of this kind of batteries grow, and it´s used in the peak hours, the price for that peak hours will decrease doubt to the decrease in the demand, creating a new monotone of prices.

6. CONCLUSIONS

The new methodology allows us to achieve one of the main challenges for the current electricity market, which is the transition from a passive consumer to a more active consumer.

The power term stops being a fixed component energy contracted and will depend on the energy consumed. We have found that turnover decreased in most levels of tension, obtaining the best economic signals for low voltage customers.

The proposed methodology favors customers with low utilization, but the utilization concept disappears, disappear the contracted power.

The time consumed becomes crucial, so that will allow modification of consumer behavior, shifting consumption from peak hours to the hours in which energy is cheaper.

All this is an important step because it allows:

- Efficient network prices
- To issue clear price signals between peak and peak-off hours.
- Hourly prices allow an efficient network cost allocation for customers with self-consumption.

Next steps

Calculate impact in more detail on the bill of different types of customers.

Analyze the implications for industries and businesses can have a change in current periods, as well as the implementation of dynamic periods.

Possible embodiment of pilots, to analyze:

- Level of acceptance tariff.
- Customer response to the new price signal.

Evolution model to penetration scenarios:

- Distributed generation
- Distributed storage
- Electric vehicle

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8. ANNEX

Glossary

Access charge: A fee levied for access to a utility's transmission or distribution system. It is a charge for the right to send electricity over another's wires and is not typically tied to the actual amount of power shipped.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements

Auto-producer: A natural or legal person generating electricity essentially for his own use.

Base load: The minimum amount of electric power delivered or required over a given period at a constant rate.

Capacity: the rated continuous load-carrying ability of generation, transmission, or other electrical equipment, expressed in megawatts (MW) for active power or megavolt-amperes (MVA) for apparent power.

Charge curve: The charge curve of a supply refers to the temporal representation of electricity consumption, or of the power demand of the installations.

Congestion: A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

Cost drivers: are the structural determinants of the cost of an activity, reflecting any linkages or interrelationships that affect it.

Tariff deficit: difference between the revenues that the Spanish electricity companies receive payments by consumers and regulatory costs recognized for supplying electricity.

Elasticity of demand: The degree to which consumer demand for a product responds to changes in price, availability or other factors.

Energy efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption. Savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity.

Fixed cost: Costs of generation projects incurred regardless of the amount of energy produced. Such costs normally include capital costs, the cost of financing construction (in the form of interest) and insurance.

Interruptibility service: an efficient demand management service that can be used by consumers that may stop their activity at times of saturation in the electricity system, and that obtain an economic compensation for the service provided. This demand management tools allows flexibilizing system operation and giving fast, efficient responses in the event of possible emergency situations, minimizing the impact on system security.

Kilowatt (kW): A unit of electrical power equal to one thousand watts.

Kilowatt-hour (kWh): A basic unit of electrical energy which equals one kilowatt of power used for one hour.

Load: The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

Marginal cost pricing: A system of pricing designed to reflect the cost of adding new power facilities to a system.

Maximeter: Device that measures the maximum power recorded during a 15 minute period.

Megawatt (MW): A unit of electrical power equal to one million watts or one thousand kilowatts.

Megawatt-hour (Mwh): A unit of electrical energy which equals one megawatt of power used for one hour.

Meter: Device that measures the amount of energy consumed (active or reactive). It may belong to the customer or the supply company. It measures consumption in kWh.

Metering: Describes the methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

Peak load: The maximum electrical load demand in a stated period of time. The maximum hourly demand during a period of time: day, month or year.

Peak demand: Maximun mean load per registration period within a meter reading period

Peak hours: Hours of the day when energy consumption is at its highest. Depending on the type of tariff chosen by the customer, power used during these hours may or may not incur a surcharge.

Reliability: The ability of the power system to provide customers uninterrupted electric service at their point of service.

Electric system reliability has two components: adequacy and security. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.

Reliability describes the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired.

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Self-consumption: Consumption of electricity from generation facilities connected inside a consumer network or through a direct electricity line associated to a consumer. That means that, thanks to the installation of solar photovoltaic panels or another generation system, electricity is obtained which can be injected in the home´s internal network, without having to take it from the external grid.

Self-generation: A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises.

Smart meter: An electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing.

Subsidy: Payments made from the government to individuals or firms for the production or consumption of particular goods or services. Subsidies reduce the cost of production or increase the benefit of consumption, and therefore lead to a greater equilibrium quantity in the market for the subsidized good.

Supplier: Provider of electricity to at least one end consumer. The supplier must be assigned the metering points of the end consumers it supplies.

Tariff: Standardization of the amount a customer has to pay for using electricity.

Tariff deficit: Difference between the revenues that the Spanish electricity companies receive payments by consumers and regulatory costs recognized for supplying electricity.

Valley hours: Daily period of lower energy consumption in an electrical system.

Variable cost: The total costs incurred to produce energy, excluding fixed costs which are incurred regardless of whether the resource is operating. Variable costs usually include fuel, maintenance and labor.

Voltage: The difference in electrical potential between two points measured as the root-mean-square value of the positive sequence phase-to-phase voltages at fundamental frequency.