UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY

Master’s Thesis

REGULATORY REVISION AND ASSESSMENT OF DEMAND RESPONSE INITIATIVES IN SPAIN, FRANCE, GREAT BRITAIN, NEW YORK AND CALIFORNIA

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Madrid, July 2015

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Summary

The present document is aimed to review the regulatory and practical status of different Demand Response initiatives carried out in different States as it is considered to be a pillar in the future development of the power sector. The study will help to understand what are the main issues to be solved in the years to come in each system to let demand-side participants hold a more important and active role in the wholesale electricity markets.

This Master Thesis has been developed at the department of 'Energy Policy and Regulation' at Iberdrola S.A. The main motivation of this project was to have a clear feedback on how demand response programs are likely to evolve in the studied areas and how energy policies regarding demand-side management may be developed from a regulatory point of view to benefit the power sector itself. Thus, the conclusions of this study will help Iberdrola to have a basis on how to face high-level regulatory discussions on this topic and to be ready for new changes with respect to the introduction of new forms of demand response programs. The States selected for this study are Spain, France, Great Britain, New York and California as they are part of Iberdrola's businesses area and they represent different stages of implementation of demand-response mechanisms attending to diverse operational and contextual conditions.

The methodology followed consists on a preliminary revision of the main available DRP options used worldwide. Then, each State has been categorized according to its generation mix, networks status, former experiences on DR, etc. so that a firm framework is given to better understand the decisions made on each country. Later, the main initiatives available on each State have been analyzed in detail following a four-criterion qualitative methodology, which is aimed to rank the main points that are understood to be crucial to achieve a proper and equitable implementation of demand response in the electricity markets. The previously mentioned procedure grades each State from A (best) to D (worst) attending to the extent customers are involved and the legality of figures like the aggregator; the variety of demand-response products offered and their general requirements; what are the measurement and verification procedures; which are the financing options and how risks are supported by each agent. This method shows the real grade DR is active on each State so that it is easy to identify the main points to be improved and also to compare the situation within the aforementioned regions. To conclude, each State will be assessed with the main potential enhancements to better involve demand-side participants on existing and future demand response programs.

As an advance, this study has identified that the grade of implementation of DRPs strongly depends on the operational and technical characteristics of each power system, going for instance from Spain where DR is barely deployed due to overcapacity in generation and overinvestment in networks to States as California where the variety of products is huge as cheaper ways to manage imbalances are needed and a large amount of renewable resources requires to be accommodated in an efficient way. On top of that, it has been perceived that programs as capacity markets, neglect the differences between supply and demand in the design process so that very few capacity is allocated to demand response agents. Finally, in those States where DR enjoys better legal conditions and wider variety of products, educational campaigns are crucial to increase the still low number of participants, warning customers about the benefits DR encloses. However, policymakers need to keep in mind that freedom of choice and final decisions should always depend on end-customers, as this is the only real way to empower consumers.

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1. INTRODUCTION

Thanks to **demand response (DR)**, final customers can bring flexibility to power systems by voluntarily changing their usual electricity consumption based on reactions to price signals or specific requests, and benefiting from the same. This can be done manually or automatically through the enrollment on DR programs designed by utilities and system operators. Contrary to energy efficiency, which aims to use less energy but providing the very same comfort level, DR proposes shifting loads to a different period of time but in most cases not reducing it.

DR has been playing a very active role in society for many years; for example different types of time-of-use tariffs have been offered from the beginning of the 1990s. Yet, it is becoming more significant as the power systems evolve and continue to become more complex. Recently, renewable power plants that are smaller, spread and less predictable have caused matching demand and supply, an arduous task that needs of advanced solutions and flexible systems, to quickly balance the system in a cost-efficient way. This is one of the challenges that power systems face and a possible solution would be to empower consumers by providing them with economic benefits that could make demand forecasts easier.

Furthermore, smart meters, ITs, apps or in-home devices provide new opportunities for innovation on the demand-side as customers can gradually have a more active role in the wholesale markets, which were formerly closed for them and designed fully for supplier requirements. Thus, DR is one of the tools better positioned in the power sector's horizon to cope with these multifaceted issues.

With the department of 'Energy Policy and Regulatory Prospective' of Iberdrola, during my Internship period, and leaded by the expert Francisco Laverón Simavilla, we have aimed to research the state-of-the-art of the Demand-Response-Programs (DRPs) in some regions of Europe and the U.S. to help Iberdrola foresee how regulation in this matter is likely to change and how to address future solutions to integrate demand-side participants in the wholesale electricity markets in a more efficient way.

The purpose of this document is therefore to carry-out a study on the regulatory and practical status of the most important DR programs and trials to support Iberdrola on the decision-making process towards regulatory discussions and conferences.

To do so, the boundaries and weaknesses of demand response will be discussed to subsequently study the past, present and future of the DRPs offered in power systems as Spain, France, Great Britain, New York State and California. The selection of the previously mentioned regions is based on Iberdrola's need to further understand how this new market is evolving, by determining the practical and regulatory situations of such initiatives. Hence, the most important programs in each area will be described by identifying deficiencies that lead to functioning deficiencies, low acceptance levels or bad-designed guidelines.

Additionally, a regulatory review concerning Demand Response has been conducted to establish a framework that would be easier to work with, to understand why some programs are or are not offered in certain areas and to determine the main issues new regulation should entail. The regulation study not only covers European Union and American Federal rules but also specific local regulation for each country and region. The objective is to identify the guidelines more likely to be followed in order to have greater levels of penetration of DR participants in the wholesale electricity markets in the forthcoming years.

The methodology followed consists on rating each system according to a quantified qualitative four-criterion exam based on the former studied programs and regulations. The score given to each region will respond to the most important factors DR programs and regulation might guarantee from a regulatory and practical point of view. These four criterions will consider to what extent customers are involved; what the legal status of aggregation is and how are responsibilities allocated among counterparties; which is the variety of programs offered and what are the participation requirements; what are the measurement and verification procedures to monitor the compliance and well-functioning of the programs; and how risk management and financing is approached. Each of these sections will be graded from A to D to end up giving an overall rating for the status of DR on each geographic area.

Finally, each region will be assessed in order to identify the points that need to be reinforced by giving sound and strong proposals to the features that might change in the upcoming years and cause DR grow. Then, the final conclusions will support Iberdrola by providing a clear starting point on how DR regulation could grow locally and globally. These conclusions will help the Department to held regulatory discussions about how to approach DR development in the studied countries.

2. Definition of Demand-Side Management

2.1. What Does DSM Stand For?

In order to refer to demand-response programs it is necessary to firstly talk about demand-side management. According with the definition given by Wikipedia, **demand-side management (DSM)** or energy demand management consists **changing of customer's energetic behavior** throughout several financial, educational or other methods. The main target pursued is to make consumers to use less energy especially during peak or critical periods or just to shift load from peak to non-peak periods flattening the load curve so that the electric system can be managed in an easier and cleaner way. Demand-side management does not implicitly seek overall energy consumption reductions but to decrease the investments necessaries for new peaking power plants and networks extensions and reinforcements. Such an example could be the use of battery banks that store energy during peak hours and release it during valleys or off-peak periods.

The first institution that brought this term to the energy industry was the Electric Power Research Institute (EPRI) after the oil crisis of year 1979. Today's trends are about a faster and more comfortable implementation of technologies that permit demand-side to be an active participant in this game thanks to ITs.

Although reducing the demand of energy may be opposite to what utilities and governments have done over the history from the industrial revolution, demand response programs (DRPs) bring a wide range of new opportunities regarding energy services. In this concern, energy prices have experimented drops mainly due to economies of scale, technological advances and so on and so forth.

Moreover, economic subsidies are still common in many countries as a way of economic management tool, typically used in central planned countries. However, nowadays energy and availability of resources is to be depressed as energy demand is becoming more and more important for energy efficiency objectives.

2.2. Types of Demand-Side Management

Within the family of demand–side management there are three different approaches or tools that can either be used independently or as a whole:

- **Energy Efficiency:** any mechanism or action that tries to develop the same functions as formerly but using less energy.

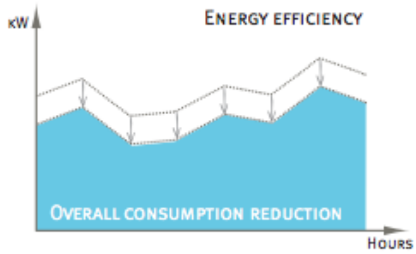


Figure 1. Energy Efficiency concept. Source: Eurelectric.

- **Demand-Response:** referred to any program or tool that aims to shift peak demand to periods with less demand. It complies every kind of method that pretends modifications on consumptions habits of electricity of end-customers residential, commercial or industrial. It is in the end a wish of changing consumption's behavior.

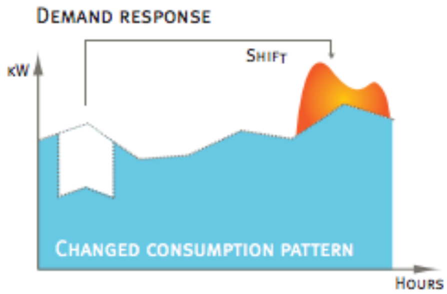


Figure 2. DR concept. Source: Eurelectric.

As it was mention in the introduction of this document, this thesis will **only focus on demand-response programs** since they are understood by IBERDROLA S.A. to be the one of the cornerstones the power sector future and are expected to play a key role in the very near future and consequently utilities may need to adapt and be ready for this new reality.

2.3. Objectives

The different targets that demand-response programs enclose are typically related to demand/supply relief. The main aims of such programs are:

- **System Reliability:** as EPRI stated (Electric Power Research Institute, 2014) low levels of quality of supply and unexpected outages make around $100 billion economic losses yearly. Since DR mechanisms are able to reduce peak load during critical periods, the overall reliability of the electric power system might be increased.

- **Cost Effectiveness:** it is reasonable to see demand management systems as cost reducer since in the end they just look for reduction of peaking capacity and therefore total costs decreases. Moreover since load curves are expected to be flatter, line losses and investment in networks shall also be lower. But it is not all about reducing peak load; the predictability that DR programs bring would help to reduce ancillary services costs as well as reducing the need of reserves. Also they may imply cheaper market prices in the long term once those programs are fully implemented.

- **Economic Efficiency:** meaning that the final prices paid by customers reflect the real changes on production costs so that demand can be managed accordingly.

- **Risk Management:** if customers keep updated information of the electric market trends then they would be able to hedge risk against price spikes and utilities shall bear fewer risks accordingly to higher predictability.

- **Environmental Concerns:** peak load plants are commonly the ones which contribute more to emissions since they are based on more pollutant fuels. Therefore the peak reductions brought by DR mechanisms lead to a future with fewer emissions of pollutants and less transmission and distribution investments.

3. Types of Demand-Response Programs

The concept of demand-response programs (DR) has been discussed for so long formerly in a theoretical way and latter applied to some electric systems or countries. There have been many trials to implement different kinds of DR programs worldwide, but this study will only cover those experiences interesting from the point of view of IBERDROLA S.A, either because they have been implemented in countries where IBERDROLA S.A. develops its activity or other countries with a stable regulation and low risk that may be interesting for the company.

The two basic categories appointed academically to address how a demand-response mechanism is designed are:

- **Load Curtailment Programs (LCP):** they are **quantity-based** programs that look for changing the consumers' behavior to benefit the whole system. They seek for giving the TSO/DSO the power to modify the demand at any given time by means of flexibility. They may consist on paying customers to reduce their consumption during peak hours or even control home appliances remotely (e.g. air-conditioning machines control or interruptible mechanisms).

- **Dynamic Pricing Programs (DPP):** they typically are **tariffs** designed to send demand **price signals** that make them change their consumption pattern voluntarily. In short, it consists on bringing customers the option of getting an economic incentive by means of lower peak consumption.

Although both families of programs differ a lot, most experiences and programs already implemented combine issues of each part, to attain a more effective use.

3.1. Load Curtailment Programs

According to (The World Bank, 2005), LCP are those programs either based on up-front payments in exchange of the availability of certain appliances to be switched off and also incentive mechanisms that look for enhance the performance of customers.

A first group in this section could be called **Direct Load Control Programs (DLC).** DLCs consist on direct shedding of appliances such as air conditioning machines through remote control mechanisms. Thus, in cases of critical demand levels, the SO is able to curtail some of this load to balance the system. Customers that consume under these mechanisms are paid in advance.

Another path of LCPs are the so-called **Curtailable Tariffs, Demand Bidding or Buyback Programs.** In this case, customers agree to reduce their load to pre-specified levels as mentioned in (The Citizens Utility Board and the Environment Defense fund, 2015). Each one of these pre- specified levels receives different payment incentives. In the end the payments are done for each MWh of consumption reduced in critical energy blocks.

In this context there are two kind of market-based programs, the first one dealing with emergency situations by improving system reliability and the second one that deals with economic scenarios with the aim of hedging wholesale prices' risk. California, New England, New York and Pennsylvania are States that have adopted full-scale mechanisms in the past.

Usually these programs are launched by the ISO that depending on the State also act as Market Operator. Although any kind of customer is eligible to enjoy this kind of mechanisms, it is common that large commercial and industrial customers play a key role in such programs since they are commonly more likely to have the flexibility needed to curtail peak loads in a short period of time. For instance many factories have small CCGT or stand-by generation that can be quickly started-up or shut-down.

Often payments are offered in two parts. The former is a reservation payment expressed in $/kWh per month while the second one is expressed in terms of $/MWh of load curtailed. In regular basis this reservation payments cannot constitute a share greater than the 20% of the total incentive payment and in some cases there is even a penalty for non-compliance.

Another way to affront incentive payments is by demand bids, in other words, customers bid load reductions in MW at pre-specified prices. However, the experience of these payments has not shown good acceptance among demand owing to the fact that requires time and formed people who cares of the bids to be done.

3.2. Dynamic Pricing Programs

Dynamic Pricing Programs are those mechanisms designed to reduce the system costs for utilities and rise down the energy bills by penalizing severely the use of electricity in critical or peak periods. As any kind of demand-response program its final aim is to shift load from peak to off-peak periods in order to flatten the demand load curve.

One of the advantages seen concerning DPPs is that they can be effectively applied either in fully deregulated systems and regulated systems. Typically the electric utilities are the agents who design, control and evaluate these programs. They launch them owing to the need of modern metering devices and billing systems. Moreover, the programs sometimes include the use of controlling equipment, for instance smart thermostat (Nest), smart meters and other equipment.

In regular basis there is no constraint regarding to the sector of people that are eligible to take part on these mechanisms. However, the international experiences show that at the former stages the programs are firstly implemented only into industrial and/or commercial large customers due to the fact that it is easier to assess the impact of such programs when higher demand-side actors are involved in.

Inside the DPP family it is possible to distinguish between **volumetric and capacity tariffs**. **The former** are oriented to send the proper **energy consumption signals** to consumers so that they try to modify the demand profile at any time, in a whole. **The latter** envision sending proper **signals regarding the power used at each moment**, thus they are more focused on reducing just consumption during peak periods.

Note here that there also exist hybrid solutions that contain both dynamic price tariffs and some clause including an interruptible device option .In the next table, given by Eurelectric the different families inside the DPPs and its objectives are shown.

Network pricing approach	Possible options within this approach:
Volumetric tariffs (€/kWh)	1. Flat (fixed price for a fixed amount of energy) 2. Fixed (fixed price per unit of energy/kWh) 3. ToU (price per kWh depends on time of consumption) 4. Event driven including critical peak pricing (prices depend on events e.g. higher prices if peak occurs) 5. Dynamic including real time (dynamic prices e.g. depending on wholesale prices)
Capacity (€/kW)	1. Flat (fixed price for a predefined capacity) 2. Variable – e.g. two capacity levels (different capacity levels defined, one price for each level)
Two part tariffs (€/kW) + (€/kWh)	Combination of the above options (for example ToU, event driven, dynamic options possible within the energy component)
One of the above + System services contracts	1. Interruptible tariff options (e.g. lower network tariffs for giving the option to control a predefined amount of load) 2. Other

Figure 3. Tariff Designs. Source: Eurelectric 2013

From now on, the different options that have been tested and discussed worldwide will be introduced like:

- **Time-of-use pricing (TOU):** day is divided into price periods.
- **Critical Peak Pricing (CPP):** during critical periods, electric prices are increased a lot.
- **Extreme Day Pricing (EDP):** same as CPP but the higher critical price is set during the 24 hours of the day of a certain number or days per year.
- **Extreme Day CPP (ED-CPP):** variation of CPP in that critical price applies only on critical hours of extreme days and TOU is not implemented.
- **Real Time Pricing (RTP):** prices vary on hourly or sub-hourly basis and customers are notified in the day-ahead or some hours ahead.
- **Peak Time Rebates (PTR):** economic incentives are given in MWh basis reduced during critical periods.

Note that EDP and ED-CPP are hybrid mechanisms so they will not be explained in this chapter.

As stated in (The World Bank, 2005), each tariff rate represents a different risk exposure to the customer-side and to the generation-side. Such an example are RTPs in which the costs are simply passed from the utilities to the customers in real time, therefore there might be no risks at all on the generation-side since the customer is taking all the risks concerning the price volatility. On the contrary, CPPs are much more risky for utilities than customers as a result of the ex-ante knowledge of prices that consumers have. The trade-offs of the different DPPs are shown in Figure 4.

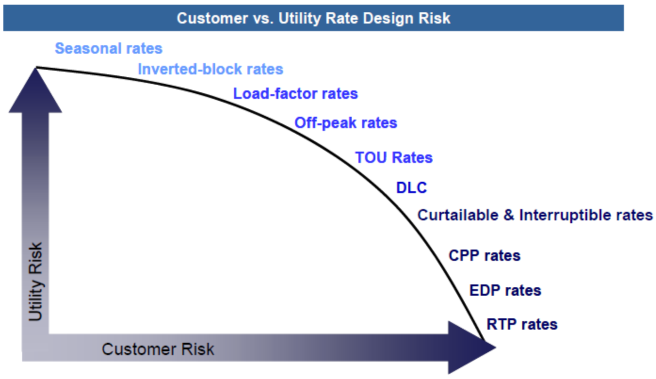


Figure 4. Customer vs. Utility Rate Design Risk.

3.2.1. *Time-of-Use Pricing (TOU)*

Accordingly with (The Citizens Utility Board and the Environment Defense fund, 2015), a TOU rate is a tariff in which the day is divided into different block periods, normally including peak periods (hours with higher prices, typically in the afternoon) and off-peak periods (those with cheaper energy costs, commonly the mornings and evenings). This is the simplest case of TOU rate, nevertheless in many systems the TOU rate divides the day in many more periods depending on several factors.

It is important to keep in mind when designing a TOU rate that it may group both effectiveness and simplicity for the customers. As customers are also looking for stability, the prices should be as much stable as possible aiming to become familiar to users and letting them to shift load to off-peak periods easily. Figure 5 shows a basic implementation of a TOU rate, in this case in Illinois:

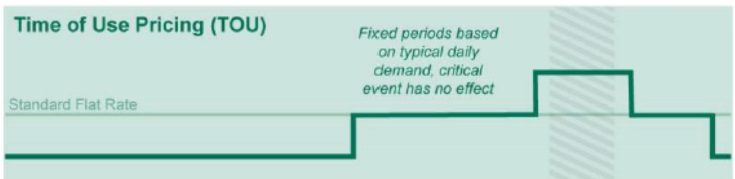


Figure 5. Example of TOU Rate.

Theoretically talking, the benefits that TOU rates bring to the system are:

1. Opportunity to reduce energy bills by shift consumption to less expensive hours.
2. Better allocation of costs since common costs are paid attending to consumption patterns. In flat-rates users with a higher level or consumption are being subsidized by those who do not.
3. Flattening load curve thus peaking plants are not often needed. Also network costs shall be decreased.
4. More efficiency thanks to less losses in transmission and distribution. Also less pollution.
5. Less need of ramping plants capable to start producing in a short period of time in advance. Therefore more ability to integrate RES-E.

- **Objective:** to reduce energy demand during peak hours to avoid or defer investments in new production capacity and better reflect the true cost of supplying electricity at different times of day.

- **Customer participation:** move certain household activities to off-peak periods (normally laundry, dishwashers, lower electric heating and Air Conditioning (AC) usage, etc…)

- **Enablers:** smart metering technologies and automation of selected loads (AC/Electric heating/Electric water heater). Feedback on energy use and price.

- **Customer reward:** reduced energy bill due to shifting activities to lower price periods. Reduced cross subsidies as the price of electricity better reflects its cost. "Green" attitude – doing the "right thing".

3.3. Critical Peak Pricing (CPP)

As it was discussed before, DPPs especially when they account with certain technologies might be very useful for customers and utilities to reduce demand better than simple TOU tariffs or CPPs without making use of technologies.

A CPP programs is basically a mechanism that penalizes severely the use of electricity during critical periods in which demand is very high. They are often combined with TOU programs in order to make tariffs more flexible and reasonable. However the basic idea lying at this point is that the price of electricity during those periods is drastically increased and the ratio between the critical price and the non-critical one varies depending on the system, as seen in Figure 6.

Figure 6. CPP Program Basic Example.

3.3.1. Former Examples of CPP Programs

One of the former experiments that are still operating nowadays in this concern was the family of tariffs released by EDF in 1995 called **"Tempo".** As presented in (The World Bank, 2005), this program features two daily pricing periods within 3 different kinds of days. These days are represented by the three colors of the French flag and correspond to least-expensive days (average of 300 days) –Blue, medium-price days (around 43 per year)-White and the most expensive days (around 22 per year)-Red. The ratio between Red and blue days use to be around 15/1 marginally speaking.

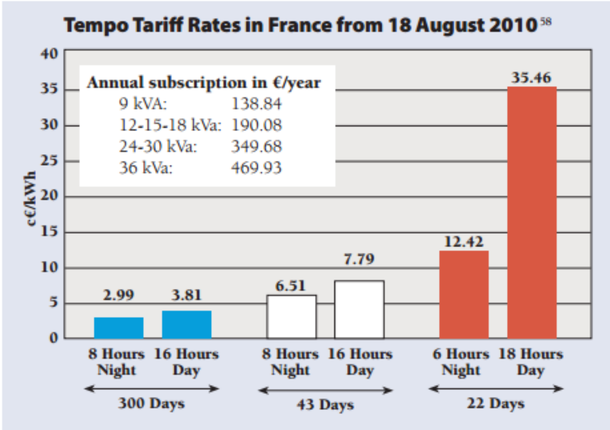


Figure 7. Tempo Tariff Rate Example.

Also, as mentioned in (The World Bank, 2005), the *"Good Cents Select Program"* launched by Gulf Power in Florida consists on a three-block TOU rate that occupies the 99% of the total hours of the year with a peak price of $93/MWh that is likely to be a 60% higher than the flat rate average price and twice the shoulder price. For the above mentioned critical period this utility has the option to call for a spike price of $290/MWh that is the typically the peak price times factor 3. This critical price applies only when critical situations are found during the operation of a normal day or with more time in advance if possible.

Moreover participants are equipped with a programmable thermostat capable of automatically adjust the heating and cooling loads and also three additional issues such as water heating and pool pumps. A maximum price cap can also be programmed to forbid the usage of appliances when prices are higher. The results found have been that peak period's consumption was reduced in a 22% while reductions on critical periods accounted for 42% according to (The World Bank, 2005).

At the same time a program called **"Statewide Pricing Pilot"** was initiated in California in the years 2003-2004 including a wide diversity of TOU and CPP models. Each of those models involved two clusters of peak and off-peak prices. The average numbers recorded on customers involved in TOU rates were 23% discounts during off-peak periods. But the greatest savings were encountered in clients with CPP rates since prices out of the critical window were a little bit lower than those used in TOU rates.

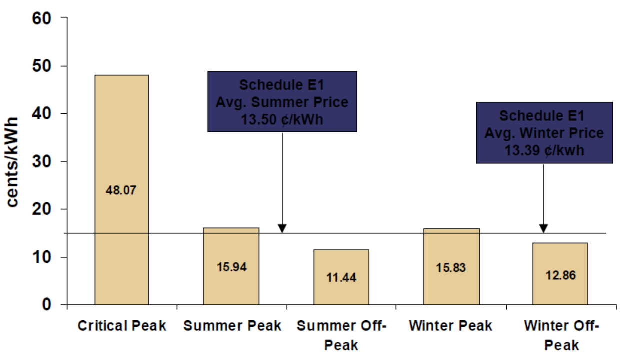


Figure 8. SPP Program's CPP Tariff.

Figure 9 shows the noticed variation of prices paid by customers of the San Diego Gas and Electric area on one kind of rate or other. For instance, the blue line shows the prices paid by people still attached to flat-traditional rates.

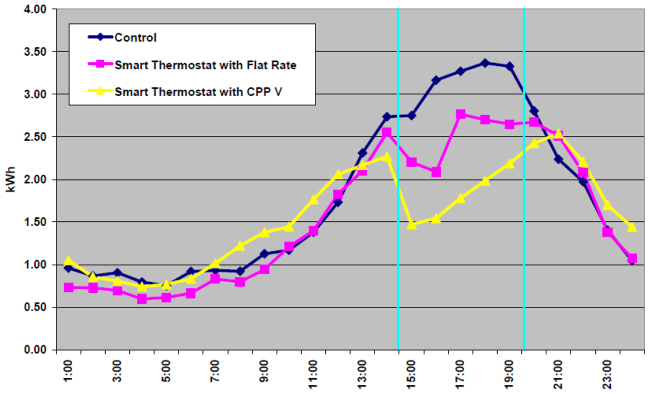


Figure 9. Histogram of Electric Prices in San Diego Area.

3.3.2. Critical Peak Rebates (CPR-PTR)

The critical peak rebates or peak time rebates are a mechanism very similar to the CPPs discussed in the previous section. The main difference lies in that now instead of setting a very high rate for those hours when demand is at the top, now the customers might receive economic incentives (rebates) per each kWh reduced during this very period. Typically the level of these payments is similar to the prices used in CPPs during the critical periods. Figure 10 shows the basis of this type of program.

Figure 10. CPR/PTR Example.

From this picture it can be inferred that customers would be more open to reduce their consumption during such peaks since the view from the customer's side is now to "make money". Usually these rates are designed in a way in which the flat rate is slightly cheaper than the traditional flat rate and the peak price reaches the previous fixed flat rate price. Therefore, not only customers may be happier to pay less in regular basis but also to have the opportunity of saving more money from time to time.

On the other hand, utilities face a less comfortable position if comparing with the CPP rates. Although the concept of both programs is the same, in principle utilities might improve the system's efficiency in the same way but obviously it is not as appealing to make payments during critical periods than recollect money.

One example in which both CPP and PTR programs where applied was the pilot launched in Baltimore by BGE in 2008, called "SEP Pilot", where firstly a group of customers enjoyed CPP rates for a year and afterwards PTRs were introduced to benchmark both programs and see their boundaries, drawbacks and the level of acceptance.

- **Objectives (CPP and CPR pricing schemes):** reduce energy demand during peak hours to avoid or defer investments in new production capacity. Better reflect the true cost of supplying electricity at different times of day.
- **Customer participation:** turn off selected appliances and delay certain household activities when notified of a critical peak period (typically laundry, dishwashers, lower electric heating and Air Conditioning usage, etc…).
- **Enablers:** smart metering technologies and automation of selected loads (AC/Electric heating/Electric water heater). Feedback on energy use and price. Notification of critical peak periods.
- **Customer reward:** reduced energy bill due to shifting activities to off peak periods (CPP) / Receive payment for lowering electricity usage during critical peak periods (CPR). Reduced cross subsidies as the price of electricity better reflects its cost. "Green" attitude – doing the "right thing".

3.3.3. Real-Time Pricing (RTP)

As it was introduced previously, RTP programs represent the natural way of transferring real-time pricing to customers since the point of such mechanisms is to make the consumers to be aware of the pricing evolution throughout the day. Thus, all the responsibility is held by the demand so it is the most comfortable program from the utilities point of view. This is the main reason why RTP programs did not succeed as much as other DPP programs. However there has been some international trial that have studied their implementation into real system. Some of these experiences will be introduced later on. Figure 11 shows the typical functioning of these rates can be seen:

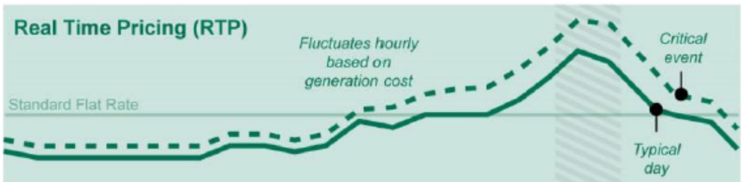


Figure 11. RTP Rate.

One of the most important programs run in the World was done in Georgia during the period 2003 to 2006 and permitted customer with 900 kW or more capacity to put their load on tender.

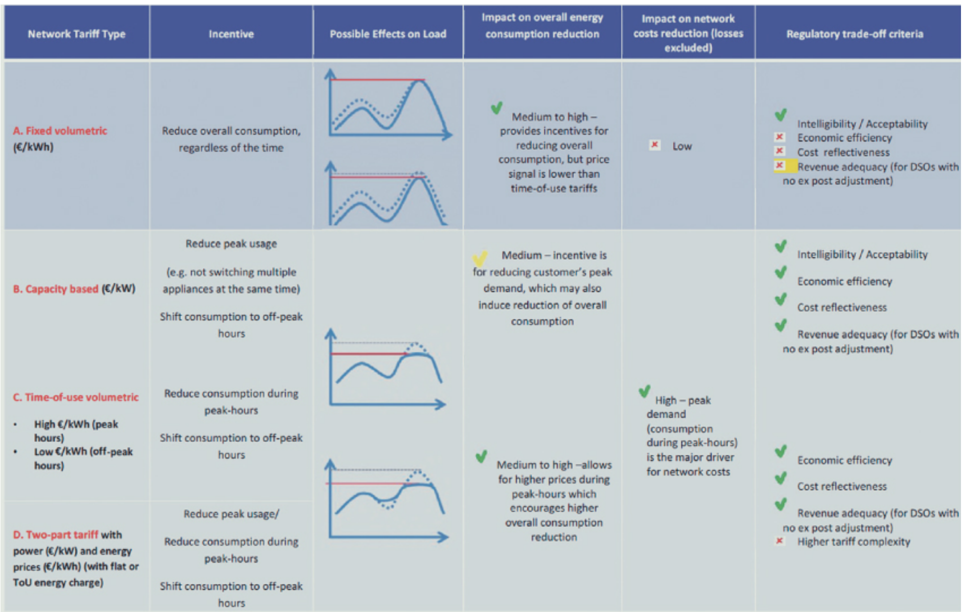
The experience showed that notable peak saving could be achieved. For instance when the prices reached $6.40/kWh the reductions accounted up to 850 MW (out of around 2000 MW). Moreover the implementations of this RTP rate brought economic growth to the community with more electrification penetration and substantially load reductions.

Furthermore the utilities noticed that many more customers were willing towards this tariff method since they envisioned not only lower cost electric power but also pain relief when market conditions established higher or critical prices by means of incentives paid by the Georgia Public Services Commission.

On top of that, Georgia Power experienced the wish of an important quantity of customers to hedge risk against high electricity prices. Hence they developed a variety of risk-management products to meet this need.

The data studied afterwards arose light on industrial intensive customers, especially paper and chemical companies that had exhaustive consumption patterns, because they were the sector with higher reductions in consumption during peak hours. Other public buildings, hospitals or stores demonstrated to be also responsive to real-time pricing. The following box and table summarize the impact on the network and in the system as a whole that the different approaches provoke.

- **Objective:** reduce energy demand during periods of high prices to avoid or deter investments in new production capacity. Reflect the true cost of electricity and enhance its price signal.
- **Customer participation:** turn off selected appliances and delay certain household activities when notified of a period of high prices (typically laundry, dishwashers, lower electric heating and Air Conditioning usage, etc…). Empower Demand.
- **Enablers:** smart metering technologies and automation of selected loads (AC/Electric heating/Electric water heater). Real-time feedback on energy use and price. Notification of high price periods.
- **Customer reward:** reduced energy bill due to shifting activities to lower price periods. Reduced cross subsidies as the price of electricity reflects its cost. "Green" attitude – doing the "right thing".



Network Tariff Type	Incentive	Possible Effects on Load	Impact on overall energy consumption reduction	Impact on network costs reduction (losses excluded)	Regulatory trade-off criteria
A. Fixed volumetric (€/kWh)	Reduce overall consumption, regardless of the time		Medium to high – provides incentives for reducing overall consumption, but price signal is lower than time-of-use tariffs	Low	Intelligibility / Acceptability; Economic efficiency; Cost reflectiveness; Revenue adequacy (for DSOs with no ex post adjustment)
B. Capacity based (€/kW)	Reduce peak usage (e.g. not switching multiple appliances at the same time) Shift consumption to off-peak hours		Medium – incentive is for reducing customer's peak demand, which may also induce reduction of overall consumption	High – peak demand (consumption during peak-hours) is the major driver for network costs	Intelligibility / Acceptability; Economic efficiency; Cost reflectiveness; Revenue adequacy (for DSOs with no ex post adjustment)
C. Time-of-use volumetric • High €/kWh (peak hours) • Low €/kWh (off-peak hours)	Reduce consumption during peak-hours Shift consumption to off-peak hours		Medium to high –allows for higher prices during peak-hours which encourages higher overall consumption reduction		Economic efficiency; Cost reflectiveness; Revenue adequacy (for DSOs with no ex post adjustment); Higher tariff complexity
D. Two-part tariff with power (€/kW) and energy prices (€/kWh) (with flat or ToU energy charge)	Reduce peak usage/ Reduce consumption during peak-hours Shift consumption to off-peak hours				

Figure 12. Tariffs' Impact. Source: Eurelectric.

4. Current Policy Framework Status

4.1. In Force European Regulation

According with (SEDC, 2014) one of the shifting points regarding how the EU takes DR into account in their energy policies is the so-called "Third Energy Package", which **encourages** system operators to account the benefits of DR and energy efficiency when planning network extensions or enhancements. Moreover the Energy Efficiency Directive (EED), orders to ease customer access to the wholesale energy markets both in an independent way and/or through aggregators. In this context the Article 15.8 of the EED establishes:

- "Member States must ensure that national regulatory authorities encourage demand side resources, such as demand response, to participate alongside supply in wholesale and retail markets".

- "Member States must require national regulatory authorities, or TSOs and DSOs where the national regulatory systems so require, promoting access to and participation of demand response in balancing, reserve and other system services markets. This requires clarifying, and if necessary changing, what the technical or contractual requirements for participation in those markets are, e.g. minimum required capacity, timing and duration of demand response activation, notice time for activation, etc., in a way that is appropriate for demand side participation".

According with the opinion stated by this very same source, those issues required by the Article 15.8 are steadily beginning to appear in the Network Codes before the whole Directive is fully implemented in every Member State. However it is crystal clear that new enforcements in regulation regarding Demand Response are needed to really facilitate demand side to participate in fair conditions.

The way the UE is trying to enforce demand response introduction is by indirect market ruling. This can be understood as a way of avoiding direct rules which do not really appeal customers.

The 3rd Electricity Directive (2009/72/EC) as well as the Energy Efficiency Directive (2012/27/EU) requires enabling demand response to participate in retail and wholesale markets according to its technical potentials. Appropriate transposition of these rules at national level is key to enabling demand response. The European Commission has also recognized demand response as **a key tool to better link wholesale and retail markets**, as noted in its Energy Union Communication from February 2015.

4.2. U.S. Regulation

As stated in (New York State Public Service Commission, 2012), in March 2011 the **Federal Energy Regulatory Commission** issued a ruling on how people should be compensated for demand response participation **(Order No. 745)**. FERC ruled that **organized wholesale energy market operators must pay demand response resources the market**

price for energy, known as the locational marginal price (LMP), when those resources have the capability to balance supply and demand as an alternative to a generation resource and when dispatch of those resources is cost-effective.

FERC noted that doing so is necessary to preserve and enhance the competitiveness of wholesale electricity markets, something FERC and Congress have promoted across the board. For example, in the **Energy Policy Act of 2005**, Congress established a national policy of eliminating unnecessary barriers to demand response participation. FERC has long held that active participation by customers in organized wholesale energy markets through demand response helps to increase competition in those markets, but had not previously required all organized wholesale markets to compensate demand response resources in the same manner. For example, PJM has been paying the LMP minus the generation and transmission portions of the retail rate, while ISO New England has paid LMP only when prices exceeded a threshold level. Even within a given market, the continual threat of policy changes resulted in a chilling effect on the full implementation and deployment of demand response.

Seeking to remove uncertainty, FERC held that demand resources should be paid at market-based prices when two criteria are met: **capability and cost-effectiveness.**

- The DR must have the capability to balance supply and demand as an alternative to a generation resource. To be paid at market prices, demand resources must be effective at displacing the need for bringing additional generation online.

- The demand resources must be cost-effective alternatives to generation, based on a "net benefits test". In essence, this test is satisfied when the overall benefit of the reduced energy price resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources.

If both of these criteria are satisfied, organized wholesale energy market operators must pay demand response resources the market price for their energy value. FERC supports position that, for DR to reach its full potential, **people must be compensated fairly for the value they provide through interrupting their consumption of electricity**.

5. Policy Framework Needs for a Successful Implementation

In this chapter four different categories have been differentiated in order to address the requirements that are necessary to introduce Demand Response in the game with the same capabilities and rights as traditional agents. These categories are:

1) **Involving Customers.**
2) **Launch Varied Products.**
3) **Enhance Verification and Measurement Methodologies.**
4) **Ease Payments.**

5.1. Involving Customers

Guideline 1. As generation, the participation of aggregators as groups of load might be legal, fomented and permitted in any electricity market.

Nowadays the participation of demand response in both wholesale and ancillary service markets is not allowed in the vast majority or EU Member States. To some extent it can be claimed that aggregation is illegal in Europe so customer's flexibility is less valued than generation unit's one and therefore underestimated. Thus the very first goal to achieve to make DR active and successful is to accept demand as a normal generation agent that is making them legal.

Guideline 2. Customers shall be able to sign a contract with any DR Service Provider of their own choice without hurdles or threats.

The first requirement in order to involve customers is the development of easy to understand and to use programs that visibly denotes the issues the client can take advantage from. At the present time only large industrial customers are permitted to go to the markets directly while smaller industrial, residential and commercial agents need and aggregator to act as an intermediate figure between the market and themselves.

Therefore customers are not currently controlling nor benefiting directly from their own flexibility as they are BRPs who handle and benefit on customer's behalf. According with (SEDC, 2014) the main reason that explains this situation is that historically talking, flexibility was not formerly bought/sold as a commodity in the markets, it was used basically as a tool to keep the network balanced. On top of that enabling customers to go straightforward to sell their flexibility on the markets might be seen as a threat by retailers and aggregators, which would try to obstruct this "liberalizing" process.

It is then vital to succeed that customers can manage their flexibility and their acts, so that if e.g. market prices are low they can decide whether to shut-down appliances or keep them working and be remunerated for that instead of having a figure (they may want to contract an aggregator but they shall not be obliged to do so) that takes decisions without any consultation.

The reality experienced in Europe is that **those countries that have launch DR programs, tend to focus on BRP and retailer protection from big market forces** theoretically but in practice no one has succeed in that. Though countries such as **Belgium, France or Switzerland are making some progress** on that.

Guideline 3. TSOs and Regulators might supervise the enforcement of simple payment and dealing arrangements among retailers, aggregators and BRPs aiming to efficiently allocate real costs and risks to all participants.

This rule is basically the main requirement to accomplish guideline 2. As regulation defends that BRPs and retailers are responsible of customer's flexibility, it becomes an obstacle for third party access and fair competition among players. Such an example of these inconveniences arises in Germany (it will be further discussed later) where aggregators have to sign up to 5 contracts to have access to the system, one with each counterparty. However countries like UK are heading the ranking of effective DR implementation and in contrast to Germans they only have to sign 2 of those contracts, one with the customer and another one with the flexibility buyer.

To do so two steps shall be fulfilled:

- **Give independence to the aggregator.** The actual situation is that aggregators have to ask regional BRPs for permission to operate in a certain area, therefor BRPs have a strong power that can be used to block aggregators and abuse of their dominant position.

- **Facilitate easy and rational payment options for the electricity provided by the retailers or the Balancing Responsible parties.** Every kind of ratio or payment must be adequately calculated in order to transfer fair competition to the players. Hence standardize guidelines might be established by the regulator (TSO).

Guideline 4. Load grouping into aggregation pools have to be considered as a unique load unit and also have the right to make decisions on customer's behalf.

The only way for the aggregator to be useful for customers is to take care of the paperwork needed in terms of taking the place of the customer for the registering process, pre-qualification studies, and communication and measurement necessities and at the same time offering understandable and measurable benefits. **Every stage required might take place at aggregators' pool level.**

5.2. Products' Development

Guideline 5. Creation of Standardized Products which permit Demand Resources to participate in markets. Roadmap:

- **Call time:** the higher time to get ready for an event the higher participation rates.

- **Cap Capacities:** The lower the minimum quantity required to participate the higher rates of participation. The typical 50/100 MW asked in some countries are due to the obsolete communication systems that TSOs use (manual telephone calls) so an enhancement in this concern shall be considered.

- **Bid Price:** prices may be transparent and communicated beforehand. Moreover such prices shall remain the same for all Demand-Response participants. Here a distinction is needed; Pay-as-Clear (PAC) mechanisms ease participation rather than pay-as-bid (PAB) mechanisms. The reason of this is that under PAC functioning those customers with lower cost suppliers could make extra-money and then aggregators might use this income to enlarge their resource in order to attract more clients.

- **Fractioning:** as it was previously discussed one of the biggest barriers that DR customers face to enter in the markets is the typically high minimum load required participating. Therefore minimum loads should be only be set by the aggregators owing technical reasons but never be established by any other extern agent (TSO/DSO).

- **Event Longevity:** if participation and flexibility is sought the maximum number of periods is recommendable to allow participants to make bids. Thus the length of these periods should be as short as possible and with as many bidding windows as possible. Small participants do not want to switch-off/on any device for a long period of time, it must be something quick and comfortable.

- **Activation:** detailed description on how a device is connected/disconnected. This must be an aggregator's business so the methodology should be defined between aggregators and the supervising entity (TSO, DSO or retailing company).

- **Communication and Measurement:** a clear procedure has to be defined in order to be efficient and robust. It is necessary to address the proceeding differences among big power plants and dwellings.

- **Punishments:** when defining penalties, the level of income and type of business of each agent must be accounted. No one wants to participate in a market where the penalty of non-compliance is to pay the 200% of the total annual revenue made. Hence penalties must incentivize the compliance and responsible participation of agents but also be fair and reasonable at the same time.

- **Activation Frequency:** in most markets (not in the case of frequency markets where the number of activations is not as important as their duration), the lower the number of activations the more participation and the lower the total costs of the system. Once again we end up talking about the need of short bid periods which permit DR no to be available during long periods of time.

- **Time between Activations:** they should be as long as possible or the bidding window be short. Such an example is asking participants to be available every 30 minutes but only throughout a 2-hour bidding period.

- **Information Procedure:** although this point is not so relevant for generation units, DR needs to be informed in a certain way in order to be capable to react to such information since in most cases they do not have a mechanism nor someone on their behalf to manage their systems.

5.3. Measurement and Verification

Guideline 6. Launch rational measurement and communication procedures.

The main elements needed to measure and verify the availability of a DR block are:

- Standard criteria for metering installation and configuration.
- Electricity delivery methodology.
- Communication procedure.
- Minimum accuracy levels.
- Frequency of verifications.

5.4. Risks and Payments

Guideline 7. Make DR agents to be compensated according with the full market value of the service given.

An equitable payment among generators and demand is vital to design a fair market. Nowadays the typical situation is that payments are set following standards that end up making payments to be higher for generators than for demand. This is due to many issues as for instance reserves markets halve their payments according to OPEX. Nevertheless Demand Side OPEX's happens to be very low, thus flexibility coming from generation is more valued than the one coming from DR.

Guideline 8. Establish market rules and frameworks that ensure investment stability by means of rewarding flexibility and capacity fairly.

- If we are looking for high rates of participation of low cost resources and small loads then **markets may be Paid-as-Cleared (PAC).**

- **Wholesale markets have to pay for flexibility.** This can be achieved by the use of availability payments according with for example the number of on-line periods per year making therefore investments to be stable.

- **Dynamic-Pricing.** The ideal option is to give end-customers real-time pricing information so that they can react to it to make money and make the system more stable. Moreover this is very helpful to increase the use of programs such as TOU, Critical peak pricing and so on. On the other hand even in the case when that this information is not given to the end-users they might still benefit in a whole if aggregators are allowed to know this information and act on their behalf by the use of bigger load blocks.

Guideline 9. Reasonable and equitable penalties for non-compliance.

As demand-side is quite different to generation side, penalties must be established independently in order to ensure an equal treat and demand participation.

Guideline 10. Establish requisites to encourage market transparency.

To summarize, although this issue is strongly dependent on the characteristics of each power system, theory supports that **payments are done both for availability and real energy curtailed in the cases where there is an obligation for the customer to do so.** This is typically the case of LCP programs with compliance clauses signed ex-ante or new capacity market mechanisms that also do so. On the contrary **only energy payments should be done under voluntary programs**, where it is the end-user who decides whether to shed or not its load according to the information s/he has.

Regarding the nature of these payments, **opportunity cost is generally the ideal way to compensate demand response**. For instance, any customer might be willing to reduce load if they pay him the difference between what he paid in the day-ahead and the actual market price under stressed network conditions.

6. Assessment Process Methodology

This section tries to explain the basics of the methodology that has been followed and that it will be later on this document to study each of the countries. As introduced in *Policy Framework Needs for a Successful Implementation* chapter, first a regulatory overview of the laws, decrees, regulations and other documents linked to DRPs will be carefully studied. An analysis of the singularities and evolution of each power sector will be also carried out.

After the reading process, all the important information regarding to regulation and DR programs and/or initiatives will be collected and presented to my project coordinator. After the discussion process another smoother summary of each country will be held in order to proceed to the evaluation part.

The evaluation part will consist on examining the state of implementation of the 4 criteria and its 10 guidelines explained in the previous chapter. To do so the information taken in the previous steps, discussions with experts of the department, and reading of disclaimers and opinions on each country will be considered.

After having such conclusions each country will be rated on each of the four categories with a letter **A to D** from best to worst. Finally another overall assessment equally from A to D will be given to each country. An example of how this criterion is applied is shown:

Criterion 1:

	Involving Consumers. Legality of Aggregation and clear BRP-BSP parties
A	DR & Aggregation legal in all markets
B	DR & Aggregation legal just in some markets. Unclear relation BRP-BSP but still viable
C	Theoretically legal but with barriers that do not permit its technical implementation. Unclear BRP-BSP duties
D	DR or Aggregation illegal or aggregated demand not accepted as a resource

Criterion 2:

	Variety of DRPs. Appropriate requirements
A	Resources from both sides (supply and demand) able to easily participate in equal conditions and in a variety of markets
B	Participation is possible but there are still certain hurdles for demand-side participation
C	There are still big barriers to participate in programs so fair competition is not guaranteed
D	DR not allowed to participate

Criterion 3:

	Measurement and Verification procedures
A	Well defined requirements that permit aggregated demand to participate in markets
B	Requirements still in development process but do not act as an important barrier
C	Severe requirements that hardly permit demand aggregation to participate in DRPs
D	Lack of requirements or do not directly enable demand side participation

Criterion 4:

	Finance – Risk Management
A	Payments and penalties reasonable and well allocated
B	Weak payment structures with unequal payment per MW for demand and supply. Penalties may create some risks for BSP
C	Inadequate payment structures and very high penalties for non-compliance so it is risky to participate
D	Incoherent payment structure where penalties are a critical barrier

Overall Rank:

	Status of DR in the Power System/Country
A	Commercially active and established in a wide range of markets
B	Some markets are opened or integration is recently taking place
C	Not yet viable, but on the verge of being opened as regulatory changes are ongoing
D	Not yet viable nor regulatory active

Note that on each category a sub **rating +/-** can be giving to make the differentiation easier as it is a very tough task to compare DR programs between several systems and characteristics.

Finally a writing process in this very same document is done reporting about all the background studied, the analysis regarding the just explained methodology, the main different programs offered and its evolution in the last year, some upcoming mechanisms in those countries where changes are expected to happen and also a final assessment or recommendation on the main issues we think each system should improve and prioritize in order to have a liquid, clean and dynamic demand response market.

7. INTERNATIONAL EXPERIENCES. STATE OF THE ART

7.1. Europe

Although Europe is not leading the ranking of successfully implemented DR programs it is one of the most hopeful areas due to the requirements specified to all the EU countries regarding energy efficiency, reductions of CO2 emissions and share of renewable resources in the technology mix.

To do so the European Commission has stated its strong interest on implementing effective DR programs all over the Euro-Zone. One of the main guidelines in this context is the Article 15.8, the one known as the Energy Efficiency Directive, which addresses the roadmap to meet the energy requirements established for the year 2020 and also gives a detailed roster of the steps every country might follow in order to achieve these goals. Regarding to Demand Response, this Directive asks TSOs and State Regulators for free of customers in the wholesale markets through DR programs aiming to enhance the performance and contribution to the system of such programs and the participation of different agents such as suppliers and aggregators (that are intermediaries between utilities and end-users so as to they reduce costs for utilities by grouping groups of customers in load packages and at the same time they offer programs to end-consumers so that they are able to save money).

Along this section the actual state of the art of some countries about the implementation of DR mechanisms will be introduced and their weaknesses, strengths, new-policy suggestions and other technical issues will be discussed. The methodology and some results are based on the work done by (SEDC, 2014) which collects information from interviews to experts on this field of each country studied, data from institutions and also keeping in touch with TSOs, DSOs, retailing companies, aggregators, technology firms, regulators etc. Afterwards home-market reports were studied in order to research about the experience of the different counterparties. Figure 13 shows a broad approach to demand-response current situation in each country.

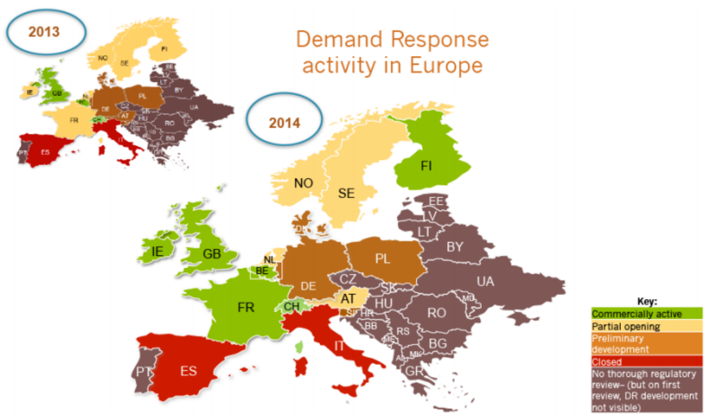


Figure 13. DR activity in Europe.

The European part will be therefore focused on some countries in which IBERDROLA S.A. is located and at the same time are interesting regarding the DR potential. In this case Spain, UK (mainly in Scotland) and France are extensively studied and others which have potential for the company will be introduced. On top pf that a general approach of the state-of-the–art of the above mentioned countries will be shown to give an initial idea on how close to real successful implementation they are. Later on a detailed explanation of the main trials run in

As a way of example, the final results provided by (SEDC, 2014) are shown in Figure 14 where all the MS are rated according to the aforementioned criteria:

2013	Consumer access	Programs	Verification	Finance/Risk	Overall
Austria	0	1	1	3	5
Belgium	3	5	1	5	14
Denmark	1	0	1	3	5
Finland	3	1	3	3	10
France	3	3	3	3	12
GB	5	3	3	3	14
Germany	1	1	1	3	6
Ireland	3	3	3	3	12
Italy	1	1	0	1	3
Netherlands	3	3	3	1	10
Norway	1	3	1	5	10
Poland	1	3	1	0	5
Spain	0	1	0	1	2
Sweden	1	3	3	3	10
Switzerland	5	3	5	5	18
Overall Score	31	34	29	42	136
Max. Score	75	75	75	75	300

2014	Consumer access	Programs	Verification	Finance/risk	Overall
Austria	3	3	3	3	12
Belgium	5	5	3	5	18
Denmark	1	0	3	3	7
Finland	5	3	3	3	14
France	5	5	3	5	18
GB	5	3	3	3	14
Germany	1	3	1	3	8
Ireland	3	3	5	5	16
Italy	1	1	0	1	3
Netherlands	3	3	3	1	10
Norway	1	3	3	5	12
Poland	1	3	3	0	7
Spain	0	1	0	1	2
Sweden	1	3	5	3	12
Switzerland	5	3	5	5	18
Overall	40	42	43	46	171
Max. Score	75	75	75	75	300

Figure 14. Results of SEDC Country Analysis.

SEDC argues that Demand Response Targets have to be developed at Member State Level in order to achieve the aims stated on the Energy Efficiency Directive. The study done by SEDC highlights the need of almost every EU country to change the regulation in order to make Demand an active participant in the wholesale electricity markets.

Aggregations are still illegal in many countries thus the European Commission has a crucial role on setting mandatory requirements to integrate DR in the system.

7.2. Spain

Background

The generation fleet and production share of the Spanish system is singular as it can be seen in Figure 15 if compared with other European countries.

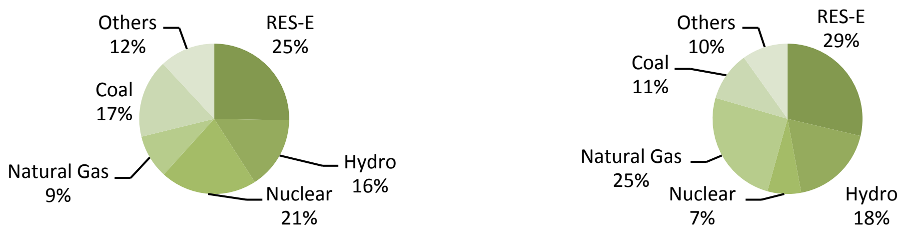


Figure 15. Electricity Production and capacity installed in 2014 respectively. Source: REE.

If we look at the graphs above, it might me reasonable to think that DR has room in the Spanish power sector as a lot of renewable capacity is in place. However it may be also rational to say that the huge amount (25%) of CCGT capacity is a good option to backup this intermittent RES energy. The question here would be whether it is cheaper to provide this backup with via DR programs or via CCGTs.

Nevertheless there is a **singularity** regarding the use of natural gas as a source of producing electricity. Contrarily to systems as the Californian one there is even a bigger share of CCGT plants, the load factor of such units in Spain is so low, it can be set at levels of around 30%. This is due to a boom of CCGT investments between 2008 and 2011 as these plants were thought to be the cornerstone of the power sector in the second decade of 21st century.

Despite, gas prices started to rise, and the overcapacity installed, accounting for a **73%** in 2014 by CNMC, made many of this plants to do not work as much as they were entitled to and to do not recover investments. Therefore the situation nowadays is that only some of these units work in regular basis and only due to constraints management requirements. The others are just waiting for very high demand peaks. All those issues make that the price of electricity in Spain is usually set by coal plants.

Attending to these reasons, it is easier to understand then that DRPs are not at the top of the priority list for the Government. Although they are, as other MS, asked to enhance DRPs and enable demand as a real participant in the electricity markets, Government and large utilities have not done big effort yet on this matter, as they understand DR as a source of more problems and an over-cost for the system.

On the contrary many associations of customers are claiming to boost DRPs so that demand is no longer passive and more options are given to customers. This is a topic of special importance for large customers (industries) and business that energy bills would have potential to decrease if wider options were in place.

Note that another setback is that the Spanish power system does **not need reinforcements** concerning the **transportation system**. Indeed, some experts have mentioned transport lines' capacity is also way higher than needed. This situation reduces the options that DR brings in the long term on helping to reduce distribution and transportation lines as less peak consumption is needed.

7.2.1. Nocturnal Tariff

It was the first one to appear in Spain for small commercial and residential consumers. It was aimed to make a first try to flat the load curves in order to reduce peaking consumption letting at the same time consumers to save money from shifting demand to nocturnal hours.

This tariff worked from 1983 to 2008 and it was thought for customer under **15 kW of contracted capacity.** The people who decided to contract this tariff, agreed to have a **55% discount** for making use of the electricity from 11 am to 7 am and a **surcharge of the 3%** for the consumption during the rest of the day, thus it was a two period tariff.

As (FENERCOM, 2007) mentions, in September 2005, when the nocturnal tariff was living its end towards a change in its traditional structure, only 1 million out of 24 million eligible consumers were subscribed to this program. The same study says that the nocturnal tariff was only worthy for those customers that had electric water tanks of at least 100 liters of capacity or heating water systems based on electricity.

- **Singularity:** same price to be paid for any installed capacity.
- **Technology:** double window/tariff meter + commuter clock.
- **Advantages:** saves in energy bill, less use of the network and less investments in peaking plants needed.
- **Drawbacks:** same price for everybody, low flexibility of options offered.

7.2.3. Time-Discriminatory Tariff

It appeared to substitute the above explained nocturnal tariff and they were implemented under the Royal Decree 1634/2006. The **main relevant changes** with respect to the former rate were:

- The prices to pay were set in an increasing relation with the capacity contracted. On top of that it was mandatory to contract the **same capacity for peak and valley hours**, contrarily to what happened before.

Rate Name	Installed Capacity
Tarifa 1.0.1	< 1 kW
Tarifa 2.0.1	1 to 2.5 kW
Tarifa 2.0.2	2.5 to 5 kW
Tarifa 2.0.3	5 to 10 kW
Tarifa 3.0.1	10 to 15 kW

Table 1. Time-Discriminatory Tariff According to Installed Capacity.

- Wider range valley periods, precisely an overall of 14 hours per day, **from 9 pm to 11 am during the winter and from 10 pm to 12 am during the summer.** In short, two periods were established for less than 15 kW customers and 3 periods for more than 15 kW.

- Discount and surcharge:

Period	#hours/day	Discount/Surcharge	Applicability
Valley	14	-47% aprox.	Winter: 10 pm to 11 am Summer: de 11 pm a 12 am
Peak	10	+20% aprox.	Winter: 12 am to 10 pm Summer: 1 pm to 11 pm

Table 2. Hour-Discriminatory Tariff.

The experience showed that this rate was only worthy for those customers that were capable of move **at least the 30% of their consumption** to valley hours, otherwise the tariff would incur more expenses to these small consumers.

This change in the regulation was argued to be unfair by many consumer associations at the time due to the fact that there was a clear need for a majority of consumers to **change their contracted capacity** and therefore make some changes to accommodate the peak consumption to the valley hours. This was because previously, since there was no need to limit the power consumed at night it was not necessary to care about the capacity limiter during such hours and therefore no need to increase the installed capacity at each dwelling. Moreover, some technical changes were required regarding boiler and accumulators' configuration.

On the other hand, under the regulatory perspective, although it makes no sense to permit e.g. a consumer with 3 kW contracted to pay the same as one with 15 kW, this measure is a disincentive to move load towards valley periods. In the former case, consumers might be willing to contract less capacity as there was no limit of consumptions at night. But now that it is necessary to establish the same capacity limit for peak and valley periods, consumers shall have fewer reasons to change drastically their habits, thus it may have fewer acceptances. Furthermore, some studies arose that the implementation of this tariff would **increase around 140 € per year** for those former nocturnal tariff participants, which means a 22% more expensive bill or a 72% more one in case of need to upgrade the installed capacity.

On top of that the **free limit** in the nocturnal tariff made peak-intensive consumers to subsidize valley-intensive customers somehow. Nevertheless it is reasonable to think that in order to better control and predict the behavior of demand it would be useful and economically efficient to set a fair limit on maximum consumption during valley hours.

7.2.4. Super-Valley Tariff

Implemented after the approval of the Royal Decree 647/2011, this tariff was thought to **incentivize the use of the Electric Vehicles** (EVs) attending the requirements of the Law 24 of "Sustainable Economy". The criteria followed to design this rate was exactly the same as for the previously introduced tariff but now the valley period was split into two periods, valley and super-valley. The idea was to bring EV owners a very strong discount during night hours, typically when EVs are parked so that it is the best time to charge their batteries. The tariff was as shown in Table 3:

Period	#hours/day	Discount/Surcharge	Applicability
Super-Valley	6	-65% approx.	1 am to 7 am
Valley	8	-45% approx.	11 pm to 1 am y de 7 am to 1 pm
Peak	10	+20% approx.	1 pm to 11 pm

Table 3. Super-Valley Tariff Design.

7.2.5. Interruptible Load Service

According to Red Eléctrica de España (REE), this service consists on big industrial customers offering to reduce electric consumption under exceptional situations, usually periods when there is scarcity of renewable generation, very high demand and/or unexpected outage of important generation units. Since this mechanism makes industries to do a big effort by decreasing their production, they are willing to receive an ex-ante set remuneration in exchange.

Until some time ago this program could be only offered to a list of pre-defined industries at a specified price. However, aiming to enhance competitiveness and make this mechanism cheaper for the whole system, REE started to organized **descending-clock auctions** in 2013 offering load-reduction blocks. Once the blocks are sold, REE has the final decision on whether to use them or not. The close of the auctions already ran in Spain are shown in Table 4:

Auction Product	MW Offered	Closing Revenue [M€]	
Year 2014	-	550 approx.	
Year 2015	810	352	**507**
Extra-Ordinary Year 2015	1190	155	

Table 4. Interruptible Service Auction Results.

However, from this system a **political lecture** can be done. It is necessary firstly to bear in mind that the Spanish Power system currently has **excess of generation** capacity thanks to the great number of new CCGT power plants installed at the end of the last decade. Owing to this, it is reasonable to state that an interruptible service for very large consumers can help to relief system contingencies from time to time but it is not frequently used as there usually are other cheaper ways to balance demand and production.

On top of that, looking at the quantities paid, and doing the assumption that the annual cost of this service is **500 M€,** for an average of **2.000 MW sold**, the price paid for this energy stays around **250.000€/MWh.** Making a bullish consideration of the prices of electricity in Spain, it can be said that the average price is around **25€/MWh.** This means that the prices paid to these industries are **10.000 higher** than the average retail prices, thus there is some hidden interest here.

According to several sources as El Economista, this issue happens because the interruptible service, as it was stated before not to be really necessary, stands for a **way to subsidize large industries**, i.e. aluminum smelters that use to complain and threat the Government on moving out of the country as the operational costs for them are very high. Since these kinds of subsidies are **illegal and affect competition** standards the Government has found this tool to do it in a legal way. This is why they are paying too much for something not useful at all.

Another clear example on that is the **second extraordinary auction** ran just some weeks after the first one. As stated in the very same article of El Economista, industries complaint that the closing prices were too low so the Spanish Government organized a new auction to re-allocate the surplus capacity so that very large industries could perceive more money for participating in this program. Such an example of this practice was Alcoa, that **retired their layoff** for their employees after achieving **extra 50M€** in this second auction. In overall, Alcoa summed up to 130 M€ from the interruptible mechanism of the 530 M€ auctioned.

According to the study done by Gesternova, **the cost of this program for the end consumer will be translated into an increase of around the 2%** on the energy term of their electricity bill, which accounts for an increase of 10€ annually.

7.2.6. Conclusions and Recommendations

The situation in Spain is clearly discouraging for DR since **aggregation is not legal**. For Spain aggregation is seen as something individual that cannot be managed in internal groups. This is to say that aggregation might provoke **less revenue of network charges as peak capacity installed would decrease**, i.e. in the case of a building which aggregates each level's loads. On top of that some utilities claim that aggregation would suppose a **loose of freedom** from customer's side if not well-designed.

Different requests to open Balancing Services to DR are being studied so new regulation regarding to this may appear in the short-term. For these reasons the rating given by given to Spain according to the aforementioned criteria is shown in Table 5.

Consumer Access	- DR not allowed participating in Ancillary Services. - Only one Interruptible Load program for large industrial customers (2.000 MW of the total). - Aggregators are not permitted. - Remuneration in load shedding program based on day-ahead prices.	D
Program Requirements	- Availability of 5 MW reductions within the 6 tariff periods (0.8 MW in the insular zones) - 55% of energy needs to be consumed during night time.	C
Measurement & Verification	- IT system directly connected to the TSO, and available capacity checked twice a year.	D
Finance & Risk	- Capacity Payments for those large industrial customers (€20/MWh). - Not fulfilling participation requirements means 100% capacity payment penalty, too severe punishment.	C
Overall	D	

Table 5. Spanish Grades.

As it has been seen up to now, Spain has accounted with some experiences regarding LCPs and DPPs but they have not succeed **neither in number of participants nor in usefulness** of the program itself. Of all those the aforesaid programs, some factors has been perceived as hurdles for a larger implementation of DRPs. Consequently some recommendations are going to be given in order to increase the number of participants and would position DR as a real option in the Spanish power markets.

- **Enhance incentives to make demand more flexible**
  It is all about quantity. Customers may perceive DR programs or tariffs as an uncomfortable partner, thus economic incentives must be great enough to be appealing for them. Some tariffs ask for at least 55% consumption during nighttime, which is almost impossible for everybody but large industries. Flexibility in tariffs and a variety of products from standard to tailor-made ones for larger customers and residential users is a then a must.

- **Information and acknowledgments campaigns**
  This is a general principle but also a key factor. Spanish customers are not generally aware of what benefits DR report. It might be very helpful to let them know how to use appliances efficiently to reduce consumption or consume it when it is cheaper to do it. Moreover it would also be beneficial to make them conscious of the environmental and investment boundaries that DR brings.

  An example of these educational campaigns is the one carried-out regarding trash recycling. It clearly was a success all over the country although there are not economic incentives in this concern.

- **Legalize demand aggregation**
  It is crucial that if small demand (residential and businesses) is expected to participate some mechanism is needed to do some tasks and even operate the system on their

behalf, this is the figure of the aggregator that has proven to be very important in other countries.

- **Access to information**
  It is an important factor in terms of making decisions both for customers and DRP promoters. It can help to reduce costs and risks.

- **Enable demand to participate in ancillary service markets as it is done i.e. in UK.**

- Some programs require minimum 5 MW reductions which is huge for small/medium residential commercial customer. This issue added to the illegality of aggregation makes demand-side invisible in the markets.

- In programs such as the interruptible system above explained, establishes penalties for non-compliance equal to the total annual remuneration of this program. Therefore **need to set rational incentives/penalties** that do not transfer such big risks to demand-side.

- **The same applies for payments**.

To summarize, the assessment of DR for Spain is quite hard if compared with other countries more advanced in this matter. As it has been already explained, the situation of the power sector, where **overcapacity and transmission networks** are ready to meet demand growth if that happens for many years, does not help at all for the development of DR.

Furthermore, the pressure that utilities are making regarding the **CCGT trouble** puts the Government in an uncomfortable situation to mandate new regulation. Besides, programs as the interruptible load service make DR to lose all the essence as there are clearly **overpayments,** the program is directed only to a very small portion of the industry sector, and it does not send strong signals to modify demand patterns so it does not attract participation and hardly ever gets active. As it was commented only a few events per year are called and at a very high price. On the contrary from the economical point of view it could be said that the market is on the verge to work properly as for instance not all capacity offered could be sold last year. Despite there are indicators of market failure such as **lack of information** for participants in this service.

To understand what the steps to follow regarding DR are it is crucial to understand which the **political objectives** in the energy sector are. In the case of Spain they not only respond to energetic criteria but also many more issues as the **reduction of the deficit**.

In this context, this study concludes that there are some signs that DPPs or simplifying ToU tariffs are not likely to have a strong weight in the future. This is linked to the decision of the Spanish Government of total discrimination in regulated tariffs. In other words, the methodology followed for the very used **PVPC rate** is **hourly billing**, which as it was commented in section 3.2, is the criterion with **highest grade of discrimination** and that transfers **higher risk to the end-customer.**

However there is still some optimism[1] about the potential growth of DR in Spain as first there is the obligation to install 100% smart meters[2] by 2018[3] and second the Real Time Pricing billing for PVPC tariffs which would lead to a change in the behavioral patterns of customers.

Then it would be recommendable to carry-out a deep discussion and study on how to address all this issues, taking into account regulators, industries, utilities, governments and customer associations since all of them are needed to refurbish this weak and inconsistent system and start building up a modern and efficient one.

7.3. France

Background

Following the same methodology used in the case of Spain, this section will firstly introduce an idea on how the French power sector looks like. The typical production share and capacity installed in the system are given respectively in Figure 14.

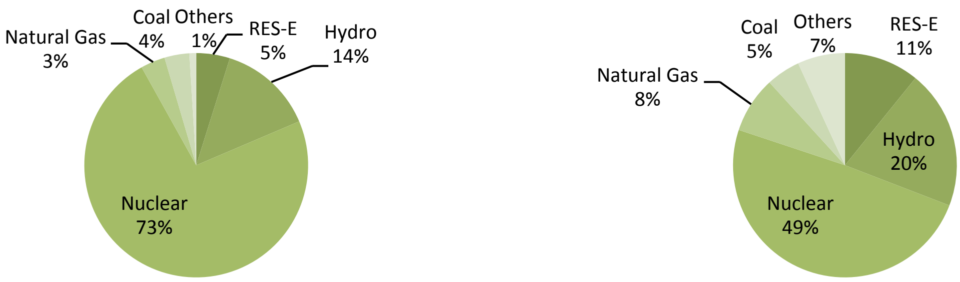


Figure 16. French power sector production and capacity installed. Source: RTE.

The French power sector in clearly dominated by nuclear power, making France to be the country in the world with the **largest nuclear share** in their generation fleet. The other leading technologies that follow nuclear further are hydro power and RES-E, mainly wind and solar PV. This market share makes France to have an inflexible system, as nuclear power stations are not able to modify their output in the short run to accommodate to demand needs.

Regarding the rest of technologies, although hydro and CCGTs are able to fit better to the load curve, their production rates are not enough high nor their installed capacity to make the power system work in the most efficient way. However, the large amount of interconnections with other countries helps to reduce somehow this handicap.

[1] With the new hourly billing systemapproved by the CNMC, to be billed under this basis customers will have to hold and Smart meter and also be integrated in the telemetry and telecontrol systems.
[2] According to 'El País', by the end of 2014, 11,9 million SM were already installed in Spain, representing the 43 %of the total. 10,9 million were also integrated in the telemetry and telecontrol systems.
[3] The rest of customers will be billed according to a weekly updated baseline profile. Note that this new hourly system substitutes to the previous three-monthly auctioning system to define stable energy prices.

On top of that, and according to energyanalyst.com, France is one of the least competitive energy markets between the EU, since **EDF controls up to the 90% of the sector**. Though EDF is privatized, there is also certain evidence that the company is still very influenced by the Government. This issue makes the market to be less competitive as it is more difficult for new entrants to participate under the same conditions. Thus, it is still difficult for BRPs to access to end-customers and offer new products.

A brief summary of some of the options and programs offered in France concerning demand response will be explained hereafter.

7.3.1. Tempo Tariff

Aiming to lower peak consumption, especially during periods of scarcity such as the winter, the French utility EDF started offering this tariff to residential consumers in 1995 after a pilot period that lasted from 1989 to 1991. According to (Smart Energy Regions), at that time EDF, which was a publicly owned company made the first trial offering a tariff that was divided into 6 blocks following real-time pricing. The number of days of each kind was noticed in advanced so that demand could comfortably adapt to the price signals.

After seeing the success of this test, EDF finally decided to offer the so-called "Tempo Tariff" henceforth 1995. This tariff was envisioned for **residential, commercial and small industrial consumers** as well. Note that Tempo is **not available anymore fore new users** but it still remains active for former subscribers.

The methodology applied to Tempo consists on the combination of two DPP alternatives joint in one tariff. These alternatives are **ToU and CPP.** The tariff accounts for 3 types of days and 2 price categories within each type of day resulting in a total of **6 price blocks.** The two price categories are a peak period from 6 am to 10 pm (Heures Pleines), and two off-peak periods for the rest of the day (Heures Creuses). The price of such periods depend on the other level, that is the color of day, formed by the three colors of the French flag, blue, white and red.

Red days represent the most expensive and critical ones but they appear only **22 times** per year. Moreover, red tariffs can only be applied during weekdays and they typically apply during winter months. **White** days are cheaper than read ones and they could be classified as valley days. They make up **43 days** per year. Finally **Blue** days are the least expensive and more common ones comprising **300 days** per year (all Sundays must be blue days). The graphical explanation of its functioning is represented in Table 6.

Les prix métropole (au 01/01/2015)

Puissance souscrite (kVA)	Abonnement annuel TTC (€)	Bleu HC	Bleu HP	Blanc HC	Blanc HP	Rouge HC	Rouge HP
		pour 1 kWh (€ TTC)					
9	125,98	0,0903	0,1075	0,1255	0,1491	0,2270	0,5894
12	201,82	0,0903	0,1075	0,1255	0,1491	0,2270	0,5894
15	233,68	0,0903	0,1075	0,1255	0,1491	0,2270	0,5894
18	256,43	0,0903	0,1075	0,1255	0,1491	0,2270	0,5894
30	641,62	0,0903	0,1075	0,1255	0,1491	0,2270	0,5894
36	787,29	0,0903	0,1075	0,1255	0,1491	0,2270	0,5894

Table 6. Tempo Tariff Rates.

Announcement: the color that will apply for the following day will be published no later than 5:30 pm on the day-ahead. There are many ways to check this information but the most common are on the website, via SMS or also plugin a specific display in the electricity socket.

Figure 17. Tempo Tariff former in-home display.

Technical Requirements: smart/interval meter to match real consumption with billing in the humblest option of the tariff. To use it with the last innovations a smart meter with 15-minute intervals, a PLC and a display are needed.

BSPs: local retailers are called for offering the product. At the time of setting the color of the day, local DSOs must inform retailers about congestions that may occur.

Achievements

Owing to the fact that **electric heating systems** are traditionally very popular in France, the potentiality of reducing demand when needed is high if comparing with other countries so it is not astonishing that big reductions are reached.

It would be discussed that the number of red and white days is too low with respect to the number of blue ones. However, the sharply increase in prices during those days and the few times that this scenarios happen tend to make people to be concerned about it thus the expected **reduction is much higher and efficient** than in the case they were the same number of days for the 3 colors.

On top of that, results show that consumption has been reduced in an average of **15% during white days** and up **to 45% during red days** making a **cost reduction of the 10%.**

Contrarily to other EU Member states, this program in France enjoys with a **high number of participants** so it represents a reliable load-shifting tool for regulators and for the network itself. Data of 2008 provided by (Smart Energy Regions) estimate **350.000 residential and 100.000 small businesses subscribers.**

7.3.2. EJP Option

This is a variation of the HP/HC tariff above explained and it can also be considered as a simple form of the Tempo matrix. Its functioning consists on the implementation of a special tariff throughout 343 days of the year and 22 high prices, EJP days, that are distributed between November 1st and Marchs 31st.

Les prix métropole (au 01/01/2015)

Puissance souscrite (kVA)	Abonnement annuel TTC (€)	Heures de pointe mobile (€/kWh)	Heures normales (€/kWh)
9	118,81	0,5770	0,1195
12	181,22	0,5770	0,1195
15	207,68	0,5770	0,1195
18	232,49	0,5770	0,1195
36	716,90	0,5770	0,1195

Table 7. EJP Tariff Rates.

As it can be understood by comparing this mechanism with the tempo tariff, it clearly represents a **less flexible tool** for the grid and it helps much less to reduce the whole consumption. Nevertheless it is very useful to alleviate the network in scarce critical periods that may mean high electricity costs in the wholesale markets.

Note that a distinction here is done regarding the **geographical zones** of the country, north, South, West and Provence, Alps and Blue Coast owing to the technical restrictions of each region.

7.3.3. Balancing Mechanism

It is a system that consists on the **acceptance of bids** to reduce or increase consumption in order **to balance the electric system in real-time**. The process to participate is based on submitting, withdraw or modify bids on the closure gates on day-ahead to real time. These deadlines are set at **4, 10 and 11 pm**. It was first launched in France in 2003 by RTE for **big industrial consumers** but it is being tested for smaller ones since 2007, **minimum 10 MW.** Therefore, although new methodologies to admit small residential consumers are under study, still only small businesses and industries are capable to participate due to both the **high capacity required** and the **long availability periods** requested, from 3 to 6 hours, not easy to manage by small consumers.

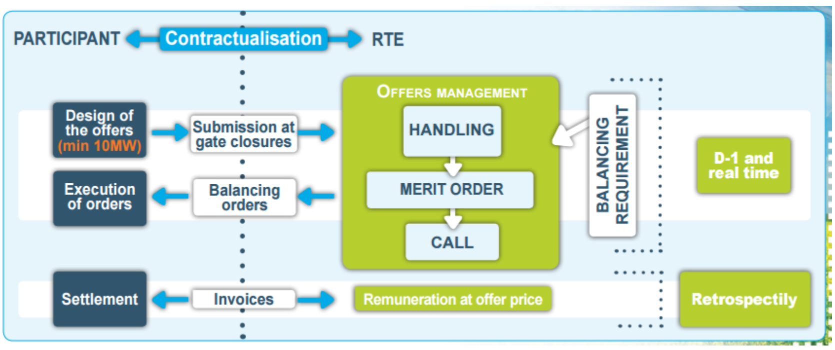


Figure 18. RTE Balancing Mechanism Scheme.

There are two types of offers:

- **Upwards**: increase production/decrease consumption/import.
- **Downwards**: decrease production/increase consumption/export.

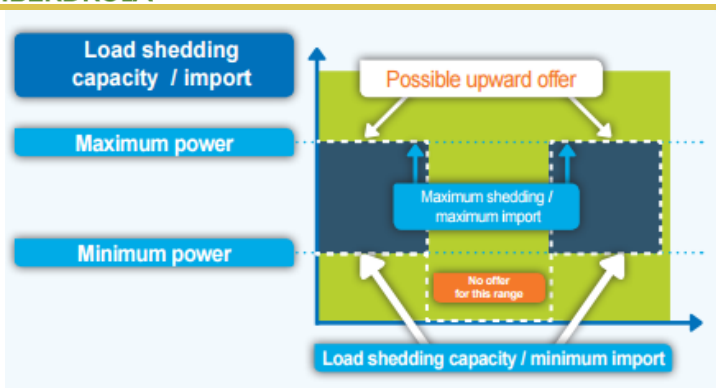


Figure 19. Example of Upward Offer for a Customer/Trader.

The so-called **Balancing Entities (BE)** that submit offers are expected to:

- Declare power flow direction (upw/dwn).
- Declare time slot/s desired. 12 am-6 am; 6 am-11 am; 11 am-2 pm; 2 pm-5 pm; 5 pm-8 pm; 8 pm-12 am.

Note that the access to this mechanism is totally free if meeting the technical requirements. The balancing mechanism gives for each half-hour period a reference price applicable for settling the imbalances based on the Average weighted prices of upward (AWPu) and downward (AWPd) balancing offers, or on the basis of the EPEX spot price.

IMBALANCE PRICE FORMATION

	Upward balancing trend	Downward balancing trend
Positive imbalance (I > E) RTE usually remunerates the BR	Epex spot price	AWPd / (1+k)*
Negative imbalance (I < E) The BR remunerates RTE	PMPh x (1+k)**	Epex spot price

*ceiling of the Epex spot Price / ** the Epex spot Price is the floor price / k: weighting coefficient

Figure 20. RTE Balancing Mechanism Settlement.

7.3.4. Capacity Market by 2016

The new capacity mechanism to start running by 2016 is strongly focused on enabling Demand Response mechanisms to access and participate as any other traditional agent. To do so the mechanism will permit DR Responsible Parties to decide whether to use one or other way to participate:

- **Implicit participation through obligation reduction.**
- **Explicit participation through certification.**

According with (RTE, 2014), the obligation peak period is limited in size and targets prioritizing peak hours. As seen in , the certification deadline will be done for the sake of easing DR to access the system and receive correct forward signals. This may lead to short term capacities to have fully access.

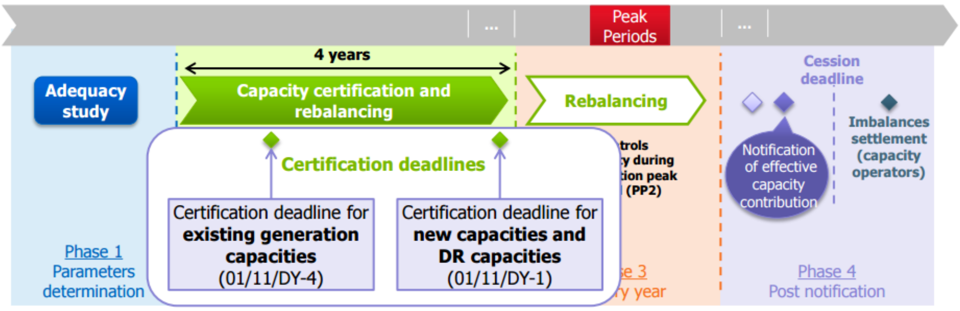


Figure 21. CM Stages for DR Participation.

Aggregation of capacities is facilitated with a low threshold of aggregation (1 MW) and the possibility to be connected to multiple distribution and transport grids.

Note that 2014 has supposed a breakthrough for DR owing to the direct valuation of DR in the energy markets, the opening process of ancillary services to DR and the introduction of realistic conditions for the entrance of DR in the capacity mechanism.

Although traditional capacity markets may be technology neutral and focused on the supply side (Batlle & Rodilla, 2014) this initiatives leaded in Europe by UK and now France suppose and advance for DR programs as they consider supply as a future tool to have a long-term stable system.

7.3.5. Conclusions and Recommendations

France is with no doubt one of the former enablers of Demand to take an active role in the power sector throughout Europe. Agreeing with (SEDC, 2014), **EDF has been the main actor** leading both industrial load shedding programs and residential programs in France. Moreover in the recent years EDF is trying to **open market** to third parties, typically residential consumer and small businesses.

Following the Energy Efficiency Directive committed by the European Commission, France has **granted access** in 2014 and it is **expected to finish a sound capacity market by 2016**. With these two points France is likely to solve the common problem that arises surrounding the **relationship among the BRP and the BSP**. However, despite the intentions are clear they are still to be guaranteed and there are still some barriers that need to be overcome to talk about real and fair participation of Demand Response. Then, Table 8 shows the valuation given to France.

Consumer Access	- Every type of reserve (also freq.) opened to DR & Aggregation[4]. - Capacity Market for G & S by 2016. - BSP can aggregate load only with one BRP area and with an ex-ante bilateral agreement.	B+

Program Requirements	- 10 MW min. bids for Frequency Reserves. (April 2014)
	    o Far from 1 to 5 MW DR friendly programs.
	- Certain consumers with signed load shedding clauses are forbidden to participate in other DR programs.
	- 24/7 freq. reserve requirement.
	- Formerly legal hurdles in contracting with the BRP,
	    o Brottes Law 2013 should allow DR participation without prior contract with BRP.
	- RTE products are generally well adapted and do not present specific incompatibilities.
		C+

Measurement & Verification	- **Enablers:** the pooled load commits requirements as an aggregator. This is crucial to allow aggregators to be an intermediary on demand's behalf. - **Barriers:** not all sites can be aggregated with other sites and other specific requisites depending on the type of reserve hard to accomplish by demand resources.	B-
Finance & Risk	- Availability payments from 10 to 40 k€/MW*year - Reasonable penalties that do not cause business risk. - Multiple aggregators already operating: Energy Pool, Voltalis, Smart Grid Energy, Dalkia and so on. - Market prices do not reflect capacity and flexibility.	B+
Overall	B	

Table 8. French Grades.

Figure 22 shows a basic approach of how DR is managed in France:

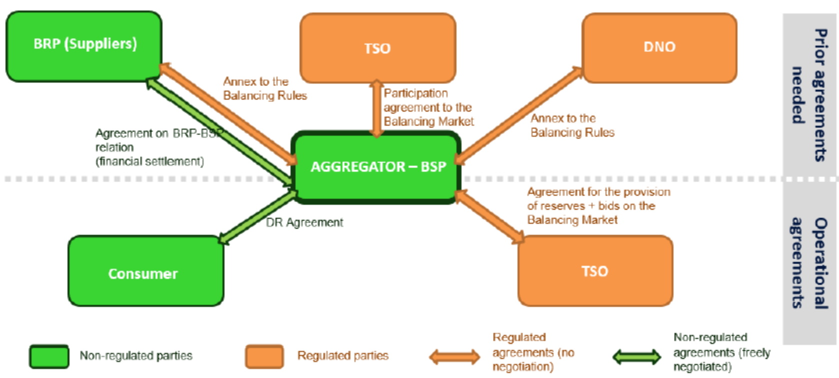


Figure 22. DR Market Design. Source: Energy Pool.

The reason why France is one of the European countries more interested in allowing demand resources to participate in the energy markets responds to their technology mix. Due to the high number of nuclear power plants and other thermal units, the French system is not

[4] According to (SEDC, 2014), Demand Side Replacement Reserves account with 700 MW contracted; Replacement Reserves with 500 MW and Frequency Restoration Reserves with 1000 MW.

considered flexible to the extent that **it is common to balance the system using nuclear power plants.** This makes the system **very inflexible and expensive** as nuclear units do not have the ability to vary its output easily. This is why one of the main concerns of RTE is to flatten the demand cure as much as possible.

However there is still a long path to be covered until DR is fully integrated and works efficiently to relief the system when there are imbalances. Some recommendations after the study of the situation of the country are listed below:

- Make DR more flexible and liquid by permitting aggregation of loads in **more than one area.**
- Permit aggregators to contract directly with any customer in the market. Nowadays a financial pre-agreement between BRP and aggregator is needed for the energy saved.[5]
- Reduce up to 1/5 MW bid requirements on Frequency Restoration Reserves.
- Abolish retailer's clauses that forbid participation of certain customers on DRPs.
- Reduce 24/7 availability requirements in Frequency Restoration Reserve. Formerly thought for generators. Need to go for 2-5 hours requirements.
- Establish monitoring measures to ensure the equal participation of demand and supply-sides in the capacity market.
- One option to transmit flexibility and DR to market prices shall be to oblige retailers/BSPs to buy **explicit certificates** according to their peak consumption portfolio.

7.4. Great Britain

Background

GB was the first country of Europe who moved towards open markets functioning. The main reason is their **singular generation mix** based on thermal power plants and the clear **scarcity of generation capacity**. Those were the two main drivers that lead them to look forward through mechanisms that enhance SoS. The actual generation mix in GB is shown in Figure 23:

[5] According to (SEDC, 2014), RTE is nowadays changing the balancing rules to favor aggregation and DR by no longer need of ex-ante agreement with BRPs; TSOs face balancing for customers connected to the transmission grid; and BRPs should face positive imbalances of customers connected to the distribution grid.

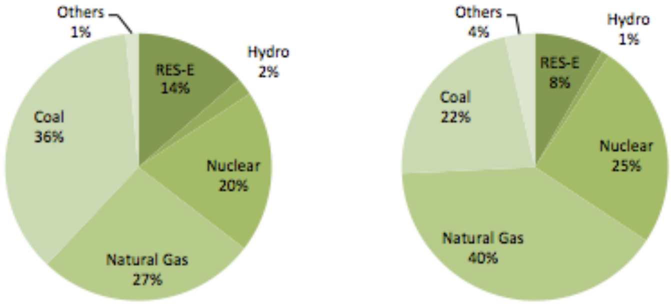


Figure 23. GB's production and capacity installed by 2014. Source: DECC.

The abovementioned scarcity and the **aim of the Government of gradually reducing the coal contribution** towards both more renewable resources and nuclear capacity, makes possible to develop a market in which demand response plays a vital role in balancing tasks as well as lowering the need of extra-capacity installed for the forthcoming years.

As mentioned by (Torriti, Hassan, & Leach, 2009) specific DR programs have been in place for some years. In the industrial and **large commercial sectors**, energy intensive users **are able to agree Time of Use and/or interruptible contracts** with suppliers. Similarly, the System Operator (ofgem) can contract such large users directly as part of their network **balancing activities**. At the other end of the scale, it is estimated that about **4.5 million UK customers** make use of **multi-rate energy tariffs**. This involves programs providing customers with the option to obtain discounted electricity rates at night. **"Economy 7"** is one example of these Time of Use programs: typically from 01:00 to 08:00 in the morning cheaper tariffs are applied so that customers using electrically charged thermal storage heaters can meet their space heating needs from off-peak electricity. In order to participate in these programs, customers need two-register meters, which most of the time consist of radio and tele-switched meters installed by their distribution network operator or supplier. Such electrical storage heating was particularly successful in the UK as a complement to the nuclear power program from the 1960s.

The requirement for nuclear generators to operate continuously caused then state-owned system operator to incentivize load shifting to provide a higher and stable night time base load, and since liberalization in the 1990s has contributed to low base load and off-peak prices. Some of the UK's large electricity suppliers have recently re-started advertising such tariff arrangements, seeking new residential customers, perhaps in preparation for anticipated expansion of intermittent renewables and new investment in nuclear power.

In the UK, more than in most other European countries, the diffusion of DR technologies is noticeable thanks to the range of devices on the market. **Penetration in the future is likely to be high with various forms of smart meters, "dumb" meters with smart boxes, and clip-on display units.** In order to understand the long-term effects on customer response of enhanced feed-back on energy use, in 2007 the British Government initiated the so-called **"Energy Demand Research Project"**. More than 10,000 households have taken part in some form of billing trial. Ofgem coordinated this trial project which is operated by consortia led by four different energy companies: EDF, EON, Scottish and Southern Energy (SSE) and Scottish Power.

DR has recently gained significant momentum at policy level. During the Report Stage of a new legislative package the Energy Bill the announcement was "I am pleased to announce that **the Government has taken the decision to mandate smart meters for all households"**. This is a major step forward; no other country in the world has moved to an electricity and gas smart meter roll-out on this scale. The existing powers in the Energy Bill will enable the Government to proceed with a domestic roll-out." The political success of smart meters in the UK is guaranteed because both the Prime Minister and the leader of the opposition seem to be inclined to seek increased consumer participation in the electricity market. For instance, in a speech on climate change in November 2007 The Prime Minister said: "For every household - over the next decade, there will be the offer of a smart meter that will allow two way communication between the supplier and customer – giving more accurate bills and making it easier for people to generate their own energy through micro generation and sell it onto the grid." The path which led to current policy thinking has been rather long. Already in a 2007 **Energy Policy White Paper** the British Government stated that electricity display monitors should be provided with all new and replacement meters and should be sent to all customers who requested one.

7.4.1. Short-Term Operating Reserve (STOR)

At certain times of the day National Grid needs access to sources of extra power, in the form of either generation or demand reduction, to be able to deal with actual demand being greater than forecasted demand and/or unforeseen generation unavailability.

Short-Term Operating Reserve is a contracted **Balancing Service**, whereby the service provider delivers a contracted level of power when instructed by National Grid, within pre-agreed parameters. The main, minimum capability requirements for the service are as follows:

- Minimum Contracted MW capability = **3MW**.
- Contracted MW must be **achievable no later than 240 minutes after instruction** from National Grid.
- Contracted MW must be **deliverable for no less than 2 hours**.

There are two forms of payment that National Grid will make as part of the service:

- **Availability Payments**. Where a service provider makes its unit/site available for the STOR service within an Availability Window, National Grid will pay for that availability on a £/MWh basis.
- **Utilization Payments**. Where National Grid instructs delivery of STOR from a unit/site, then it will pay for the energy delivered on a £/MWh basis. (This includes the energy delivered in ramping up to and down from the Contracted MW level).

Availability Window

The Availability Window is defined as the period in which the service provider is required to be available to operate at Contracted MW. Availability Payments are made just for the duration of the Availability Window.

STOR is a year-round service, available to National Grid on a 24-hour basis. These windows vary seasonally, but currently fall within the period 07:00 to 22:30, and amount to roughly 11 hours per day. Most STOR utilization occurs within these windows.

The STOR market has been growing in volume and value for several years, due to the **reduction of flexible coal and oil electricity generation capacity**, and the increase in forms of generation which require balancing, such as renewables.

7.4.2. Frequency Control by Demand Management

This service specifically aims to prevent the fall in system frequency below the statutory limit of 49.5Hz. On a general basis, frequency does not commonly fall below 49.7Hz unless there is an unanticipated generation loss or demand increase on the system. The FCDM service allows the provision of frequency response through the co-operation of demand customers who can reduce consumption when the grid frequency drops below a pre-set level.

Drops in frequency below the pre-set level are detected through the use of low frequency relays installed on sites taking part in the FCDM service. Demand customers taking part in this service are **required to reduce demand for a period of 30 minutes when the relay detects a drop in frequency.** Once demand has been reduced, the grid frequency should begin to stabilize.

Implementation

In order to make a significant contribution to the energy demand reduction required, participant customers must represent a large amount of electricity usage, a **minimum of 3MW**. The number of such large consumers that are able and willing to participate is limited. **Energy Aggregators pool together large consumers of electricity that on their own do not meet the 3MW** requirement so that together they can participate in the FCDM program.

Approved aggregators for National Grid, provide the hardware & software solutions along with the monitoring and controls required for a company to participate in the FCDM program and generate Cashback.

The participants must provide the service within **2 seconds after instruction.** This is the reason why subscribers need special auto controlled equipment and operational metering. Moreover, the length of the service provider should not be lower than **30 minutes.**

The service is provided through bilateral negotiations with providers. National Grid provides FCDM computer equipment, tests and commissions once the Site/Agent has installed the **Tripping Relay Equipment and Communication Router.** Once the test has been completed, a Site can join the scheme subject to signing the FCDM Ancillary Service Agreement.

Once a provider has agreed terms they are required to declare availability for each Settlement Period on a weekly basis. National Grid then will determine whether to accept this availability.

7.4.3. Fast Reserves Program

Agents must be able to deliver **at least 50 MW**. Moreover the minimum incremental additions have to contain no less than 10 MW. The service must be delivered in two minutes and sustained for 15 minutes. National Grid procures 0.8 GW of which DSR contributes 38% at night through automated storage heaters.

7.4.4. TRIAD System

Background

As stated in (Flexitricity, 2010), the "triad" system is the means by which **large industrial customers and commercial users** such as steelworks, cement factories and railways. The triad system **doubles up as a peak load management mechanism**. **Triad charges are part of Transmission Network Use of System (TNUoS) charges**, which National Grid recovers every year from Licensed Generators (large power stations) and Licensed Electricity Suppliers. The TNUoS charges which Electricity Suppliers pay for the consumption of their half-hourly (HH) customers are in the form of triad charges. **The cost** of owning and operating the transmission network **is driven by the peak demand which the network must satisfy**, and is higher where demand is high and generation is insufficient. The triad charging system has been designed to **penalize consumption during peaks**, especially in highly stressed parts of the network.

TRIAD Mechanism

The "triad season" runs **from the beginning of November to the end of February** every year. Once the triad season is over and half-hourly meters have been read, **the three half-hour periods of maximum demand are identified**. These are the triads for that season, and **must be separated by at least ten clear days**. For each Electricity Supplier[6], its customers' average consumption, in each network zone, over the three-triad periods, is calculated. This is multiplied by the triad charge for that zone to create the total amount that the Supplier must pay to National Grid.

Commercial Opportunity

Because the cost of owning and operating the GB transmission network for a year is recovered in the three triad periods, consumers and small generators can save and earn money from the triad system. **Consumers, who avoid consuming during those periods, whether by turning down or by running generators, save money for their Electricity Suppliers**. A consumer or generator wishing to exploit this opportunity requires:

[6] It is the Electricity Supplier who pays for their consumers' peak usage and then internalizes the costs through the electricity bill.

- Flexibility in consumption or generation.

- The right tariff. For consumers, the triad charges must be explicit, not hidden in the unit rates.

- **Triad warnings**. Because triads are not known in advance, they must be predicted from demand and weather forecasts, and previous experience. Most Suppliers and many energy bureaus provide triad-warning services. Triad warnings vary between sources.

Examples of Historical TRIADs

Peak demand is driven by the co-incidence of lighting-up time with the end of the working day. For this reason, triads have historically occurred **between 16:30 and 18:00** on Mondays, Tuesdays, Wednesdays and Thursdays. Around the winter solstice, triads tend to occur earlier in the day. Triads are strongly correlated with temperature, so a cold snap late in the winter can cause a triad to fall later in the day.

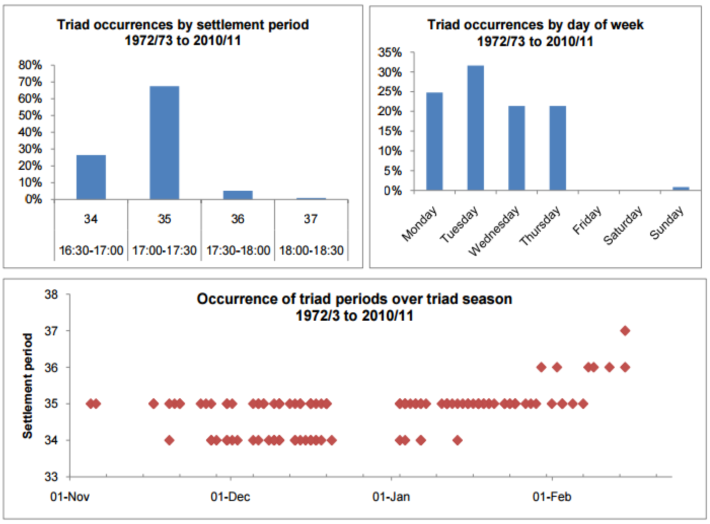


Figure 24. Historical TRIAD Events. Source: Flexitricity.

7.4.5. Capacity Market

Following the same design lines of other capacity markets discussed in other countries, the British Capacity market is an auction-based mechanism who seeks to cost effectively bring forward the amount of capacity needed to ensure security of electricity supply four years in advance.

There are 4 main points to be discussed regarding the design of the CM for DSR. From now on the participation or innovations brought for Demand Response will be introduced. All the information provided in this section has been stated in (Department of Energy & Climate Change, 2013).

Capacity Offered

The amount to be auctioned is decided yearly by the Minister. However the numbers of the first auction held in 2014 for the winter of 2018/2019 are as follows:

	Capacity [GW]	Capacity [%]
Existing Generation	33.6	68.2
Refurbishing Generation	12.9	26.2
New Build Capacity	2.6	5.2
Demand Side Response	**0.2**	**0.3**

Table 9. CM Auction 2018-2019 Summary.

The limited amount of DSR capacity to clear the auction is of note. As existing DSR capacity could either participate in the T-4 auction or the transitional arrangements, but **not both**, it is clear that the prospect of immediate income from the transitional arrangements proved more attractive and will be explained later on. For new DSR capacity, the **low clearing price** resulted in a number of potential schemes not clearing the auction.

Eligibility and Auction

A drawback could be that the capacity bid for each agent is determined by the S.O. (National Grid). The yearly auctions will be **paid-as-cleared**. To mitigate market power, bidders will be classified as either 'price takers' (which cannot set the price) or 'price makers' (which can). It is expected that most bidders will default to being price takers meaning they can **freely bid up to a predetermined threshold. DSR resources will be classified as price makers**, and will be free to bid up to the overall auction price cap.

*** Cornerstone for DR:** as DSR finds it difficult to commit to providing capacity four years ahead of delivery, the SO will run one year ahead auctions for fine tuning the amount of capacity they are really able to manage. On top of that there will be transitional arrangements for DSR in advance of the first full delivery year. These will help to increase the total volume of DSR on the system and ensure that DSR capabilities are fully exploit.

Besides, successful bidders will be awarded 'capacity agreements', which provide a steady payment for capacity in return for a commitment to deliver energy when required in the delivery year, or face a penalty linked to the value of lost load.

Existing plants will by default have access to a one year capacity agreement. Existing plants requiring major refurbishment may have access to agreements with a term of up to three years, and longer agreements are expected to be available for new plants.

Penalties

- Maximum total penalty for non-delivery will be proportional to the capacity failed to deliver times the cost of new entry (soft cap).
- In case of extra-delivery the remuneration will be the inverse of the penalty. Over delivery will be only paid under network stress conditions.

Payment

- The cost of capacity will be recovered from suppliers according to their share of peak demand.
- Penalties will be returned from capacity providers to suppliers according to their share of peak demand.

7.4.6. Tariffs

GB is one of the pioneer areas in Europe implementing DPPs in order to encourage customers to either switch load to off-peak hours or even reduce consumption. For this reason, only a few examples of tariffs (typically ToU) will be introduced here since a large variety of them can be found on each retailer's website.

Economy 7 Tariffs

Started in 1978, there are several companies who provide this tariff which consists on lowering cost electricity for a 7 hour period during the night. This means that any electricity you use during the 7 hour night period typically costs one third of any electricity you may use during the day. The tariff is only recommended for those people able to use **at least a 35% of their annual consumption at night.**

To benefit, users need to have a two rate meter that records what they have used for the day and night periods. Unlike a standard tariff meter, a traditional Economy 7 meter usually has two rows of readings, one for the day and one for the night.

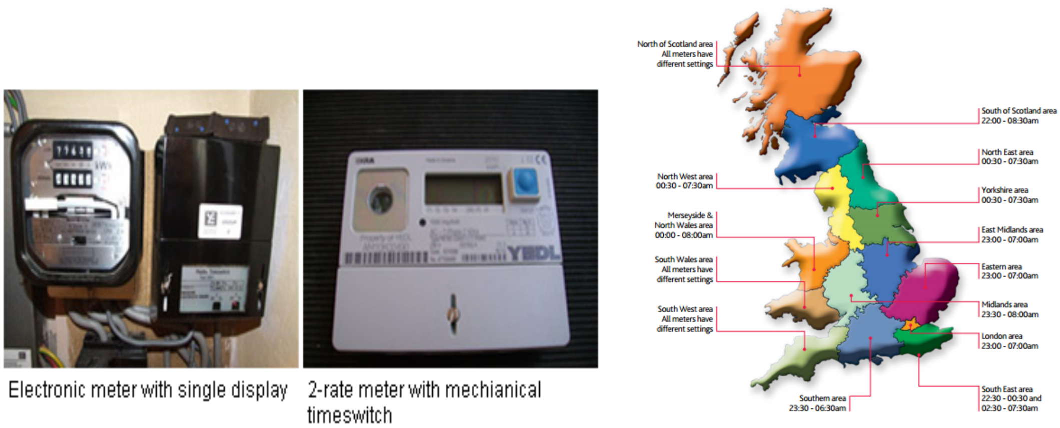


Figure 25. Economy 7 technology required and zonal distribution.

Economy 10 Tariffs

According with Wikipedia, in contrast to Economy 7, which only provides off-peak electricity during night time hours, Economy 10 tariffs provide 10 hours of off peak heating spread across night-time, afternoon and evening. The advantage of this scheme is that by matching the storage periods better to the times when heat is required, **less heat needs to be**

stored during the day, when there may be no demand for heating. The afternoon and evening periods also provide a top-up to heating systems at off-peak prices.

Off-peak electricity costs can be half of peak prices, but many Economy 10 tariffs levy an increased standing daily charge.

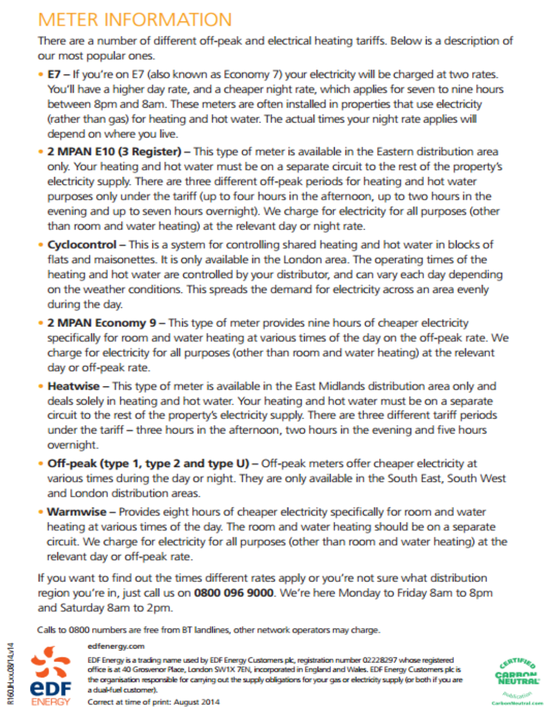
The structure of the 10 off peak hours is determined by your local DNO and they vary across the 14 regions in the UK. Times are switched automatically, and it's common for the switching times to be locked to either GMT or BST when the meter is installed. Some metering systems use a radio tele-switch controlled by the supplier to vary switching times, and affect the Daylight Saving Time switchover twice a year. Economy 10 **thus requires a special multi-tariff meter, different from an Economy 7 meter**.

Experience of E7 and E10

- E7 has been supported by all major suppliers.
- E10 (or heatwise): supported only by EDF, EON, and SSE. Low electricity rate between 7 pm and 5 am plus 10-4pm.

E7 and E10 tariffs are normally **used by people with electric storage heating** since high off-peak use is needed to benefit. Both tariffs have been available for so many years in GB without the use of smart meters albeit most of the meters had tele-switch capability. **31% of the electricity consumed in GB in 2008** was reported to be acquired by any of the former mentioned off-peak tariffs.

A large variety of tariff designs are offered by the 18 different retailing companies of electricity licensed in GB. Some of the ones offered by EDF Energy are shown in Figure 26.


METER INFORMATION

There are a number of different off-peak and electrical heating tariffs. Below is a description of our most popular ones.

- **E7 –** If you're on E7 (also known as Economy 7) your electricity will be charged at two rates. You'll have a higher day rate, and a cheaper night rate, which applies for seven to nine hours between 8pm and 8am. These meters are often installed in properties that use electricity (rather than gas) for heating and hot water. The actual times your night rate applies will depend on where you live.
- **2 MPAN E10 (3 Register) –** This type of meter is available in the Eastern distribution area only. Your heating and hot water must be on a separate circuit to the rest of the property's electricity supply. There are three different off-peak periods for heating and hot water purposes only under the tariff (up to four hours in the afternoon, up to two hours in the evening and up to seven hours overnight). We charge for electricity for all purposes (other than room and water heating) at the relevant day or night rate.
- **Cyclocontrol –** This is a system for controlling shared heating and hot water in blocks of flats and maisonettes. It is only available in the London area. The operating times of the heating and hot water are controlled by your distributor, and can vary each day depending on the weather conditions. This spreads the demand for electricity across an area evenly during the day.
- **2 MPAN Economy 9 –** This type of meter provides nine hours of cheaper electricity specifically for room and water heating at various times of the day on the off-peak rate. We charge for electricity for all purposes (other than room and water heating) at the relevant day or off-peak rate.
- **Heatwise –** This type of meter is available in the East Midlands distribution area only and deals solely in heating and hot water. Your heating and hot water must be on a separate circuit to the rest of the property's electricity supply. There are three different tariff periods under the tariff – three hours in the afternoon, two hours in the evening and five hours overnight.
- **Off-peak (type 1, type 2 and type U) –** Off-peak meters offer cheaper electricity at various times during the day or night. They are only available in the South East, South West and London distribution areas.
- **Warmwise –** Provides eight hours of cheaper electricity specifically for room and water heating at various times of the day. The room and water heating should be on a separate circuit. We charge for electricity for all purposes (other than room and water heating) at the relevant day or off-peak rate.

If you want to find out the times different rates apply or you're not sure what distribution region you're in, just call us on **0800 096 9000**. We're here Monday to Friday 8am to 8pm and Saturday 8am to 2pm.

Calls to 0800 numbers are free from BT landlines, other network operators may charge.

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edfenergy.com

EDF Energy is a trading name used by EDF Energy Customers plc, registration number 02228297 whose registered office is at 40 Grosvenor Place, London SW1X 7EN, incorporated in England and Wales. EDF Energy Customers plc is the organisation responsible for carrying out the supply obligations for your gas or electricity supply (or both if you are a dual-fuel customer).

Correct at time of print: August 2014

Figure 26. Off-peak tariffs offered by EDF Energy.

A study carried out by (Consumer Focus, 2012), pointed out the **13%** of domestic electricity bill payers as users of ToU tariffs, primarily Economy7 (66%) and Economy10 (10%). Some differences are shown in the acceptance and happiness of ToU users depending on whether they use **gas central heating systems or storage heating**. The formers represent around the 66% of the total whilst the latters are the 24%.

Experience with the Economy 7 tariff in the UK indicates that some consumers are willing to accept a degree of automation of their electricity use. Most Economy 7 consumers in the UK already allow remote control of their electric storage heaters.

UK evidence on the importance of enhanced information to encourage consumers to shift their demand is mixed, with differing results found in the EDF and SSE parts of the EDRP trial.

7.4.7. Conclusions and Recommendations

UK is nowadays expecting how the **rules that apply the new Capacity Market** implemented in 2013 via the Electric Market Reform treat demand-side agents (e.g. **the penalty construct**). Moreover, certain financial options that are closed to DR may be revised such as Contracts for Differences (CfDs).

There is also a plan to run **Demand Response Balancing Reserves Program** but this will only be successful if the above mentioned capacity market is not only focused on the traditional generation side.

Nevertheless, **the vast majority of ancillary services are open to DR**, aggregator retailers and besides that, customers are very active.

The main program is called **Short Term Operating Reserve (STOR)** and the lion's share of ancillary services is opened to DR. Nevertheless since 2011-2012 electricity prices have dropped and **DR resources that are not available 24/7 are not competitive**. This is the main reason of the low **participation rate, 4%.** There are other programs such as the Frequency Response and the Frequency Control Demand Management that requires more issues than the STOR.

Ofgem supports DSM measures if cost-effective. They tend to use a TOTEX approach to regulate distribution prices. The situation of DR trials is active as 5 out of 6 DSOs are currently running programs like this. Such an example is the **TRIAD system.**

Moreover the brand new capacity market launched in 2014, to start operating by 2018-2019, is looking for new rules to permit DR participate fairly.

Opposite to France, where aggregators have only access to consumers in certain regions, in GB aggregators have fully access to them **in all the territory** of the country and they also have **straight access** to retailers and customers' loads without need to ask in advance. On top of that, it seems to be **needed to clearly define responsibilities for BRPs and BSPs** in order to mitigate risks and allocate costs reasonably as it is done in France.

Some of the programs offered have shown the strict requirements that ask for DR participation, so they shall be revised to set a level-field for al participants.

- **STOR Program**
  - 24/7 availability
  - Possibility to choose 1 time window (morning/evening) but revenues are severely reduced.

- **Fast Reserves Program**
  - 50 MW min. bid size. Minimum incremental additions of 10 MW per bidding unit.

- Ofgem gives permission to National Grid to develop a new DSM method by 2015 reducing business consumption from 4 pm to 8 pm.

- **Capacity Market**
  - Penalties up to **2*Total Remuneration**
  - Hard to identify capacity events.
    - No limit on event's duration and daily frequency
  - Introduction of DSM resources delayed 1 to 2 years.

On top of that, it has been addressed that **baseline methodologies do not apply for all kind of DSM resources.** Moreover programs as the FRP require IT technology systems specially adapted to DR incurring high costs for aggregators.

In the last few years the electricity (real-time) prices have been lower than usual so they do not help to incentivize DS resources. For example average availability payments are set at **12,8€/MWh** and energy payments stay around **325,92€/MWh.**

Summing up, the evaluation of the state of DR in GB is given in Table 10:

Consumer Access	- Ancillary Services opened to DR. - Short Term Operating Reserve (STOR) is the main program; Load curtailable stands for 4%. - 5/6 DNOs running DR trials. - DR expected to participate in upcoming CM auctions. - Aggregators have direct access to consumers.	A^-
Program Requirements	- DR has a weak share on STOR since it requires full time eligibility (though) or to choose a window frame (morning/evening) but payments are highly reduced. Therefore need to be changed. - Fast Reserves Program requires at least 50 MW bids.	C
Measurement & Verification	- Baseline methodologies do not work with many DR systems. - Fast Reserves call for new IT systems that suppose a high cost for aggregators.	C^+
Finance & Risk	- Real-Time price differences are not enough high to be interesting from the utilities point of view in order to launch DR programs.	B^+
Overall	B	

Table 10. Great Britain's Classification.

The schematic functioning of DR participation in UK can be seen in Figure 27:

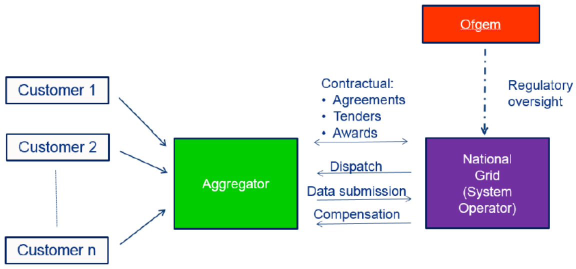

Figure 27. UK's DR Market Design. Source: Enernoc.

In short, the main points to be covered in order to enhance the regulation regarding DR markets are:

- Permit frequency markets to be opened to DR[7], with reasonable requirements concerning minimum bids accepted.
- Modify the traditional 24/7 availability requirements of some programs to take into account DR.
- Study the possibility of permitting the use of **CfDs for DR** inside the capacity market.
- Set appealing rates that encourage demand-side to participate. As an example STOR offers very low remuneration for one-window users.
- Study the possibility of subsidizing IT systems for end-customers in order to make a more efficient use of DRPs. Need to communicate and do not be billed according to the baseline methodology.
- Market **prices do not reflect flexibility** as prices in real-time do not differ that much from those of the day-ahead. Therefore need to apply mechanisms recognize the value of flexibility. One mechanism have been pointed out in this study as potential solutions to somehow boost this issue:
    - Obligation for BSPs (aggregators/retailers) to buy voluntary **certificates** according to their Peak Portfolio Potential.

Finally it is necessary to mention the need of refurbishing some general rules of the capacity market that apply to DR. As it was commented in section 7.4.5, the penetration of DR in the last year's auction was almost negligible. This issue attends to two factors, first the **higher uncertainty** that demand-side bears compared with the supply-side and second **the**

[7] According to 'Utility Week', National Grids is preparing a revolution on Ancillary Services provided by DR by 2030. The reason, the 850M pounds spent yearly in such systems.

In the next five years National Grid says it will work with commercial and industrial energy users to "normalize" the use of demand-side response before engaging with the domestic sector to broaden the scale of flexible demand capacity.

National Grid has come under criticism in recent years for opting for failing to promote the demand-side by relying more heavily on supply-side options, most notably in its winter balancing reserve which in its first round for delivery last winter paid £30 million of the £32 million total to old thermal plants with the remainder paid to those willing to cut their energy use at the time of peak demand.

still latent economies of scale, which in terms of price affect more to consumers. To solve it, this study proposes the **limited reserve of capacity offered** each year to be bought only by Demand-Response resources. On top of that, instead of carrying-out the main auction four years in advance and then tune it yearly, we propose to do a main auction from **one to two years in advance** and then fix quarterly since DR is more flexible a fast to provide a certain amount of capacity to cover future demand needs.

This measure would boost DR in the former years and make the rules more equitable taking into account the specific features of each side. Finally, closer-to real-time auctions with only DR participants would lead to higher closure market prices that **reflect better the added value of flexibility**. Note that if the need of certain power system of integrating DR is extreme, **pay-as-bid auctions** would bring higher participations as higher prices would arise.

7.5. State of New York

Agreeing with (NYISO, 2004), New York State is divided into 11 zones for the purpose of setting wholesale prices. Zonal borders represent transmission system interfaces. Like a highway during rush hour, the transmission system can get congested when energy demand is high and electricity is re-routed to different parts of the State. The wholesale market-clearing price, called the **locational-based marginal price (LBMP),** reflects the state of the transmission system when generators are selected to meet demand. Thus, it is possible for one zone to see dramatically different prices to the adjacent one. To have an idea on how the NY power sector looks like, Figure 28 represents the generation capabilities by fuel source.

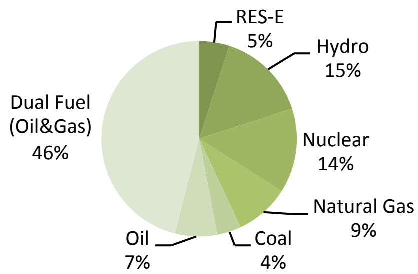

Figure 28. Generation capability by fuel source.

In the State of New York, there are two parties that provide DR programs, the NYISO and Consolidated Edison (Con Edison).

The New York System Operator NYSO runs a capacity market to ensure resource adequacy for both the short and the long term in New York State area. These **CMs are divided into 4 zones**: the New York Control Area (**NYCA**), New York City (**Zone J**), Long Island (**Zone K**) and the **G-J Locality** although there are many more zones for the operation of the rest of wholesale markets. Historically, the **NYISO has introduced DR in their capacity auctions since 1999.**

Likewise many other DR programs discussed formerly, NYISO DR programs focus on compensating customers for curtailing electricity some times per year. These programs are designed to keep stable the reliability of the electric grid and reduce the number of rolling blackouts. The NYISO is able to call **a System Emergency or Demand Response Event** usually in conditions of great consumption hours throughout the State. Then, both commercial and residential consumers who have previously agreed to shed certain prescribed load do so by request, usually from **4 to 6 hours per year** and a few times per year. Participants are afterwards paid for the service provided either if the **event has been called or not.** To ease the operation of the system **NYISO partners with aggregators who provide the requested services.** The main reason of the **high number of new aggregators is attributed to the subsidies** given for green projects and demand-response or energy efficiency improvements.

If want to **participate** in any of these programs, **end-users must enroll through a NYISO customer**, in other words:

- A transmission operator - local distribution utility
- Load-Serving Entity (LSE) – competitive energy supplier
- Aggregator or also known as Curtailment Service Providers
- Direct Customer – the one who directly buys and sells at the NYISO market

As mentioned in their website, NYISO accounts for 4 **Demand Response Programs:**

The Emergency Demand Response Program (EDRP) The ICAP Special Case Resources (SCR) Program (ICAP-SCR)	**Reliability Programs**
The Day-Ahead Demand Response Program (DADRP) Demand Side Ancillary Services Program (DSASP)	**Economic Programs**

The EDRP and the ICAP-SCR programs are ran in energy scarcity situations to maintain the reliability of the grid. Both mechanisms are thought to reduce load by shutting down large industries and big businesses, which have agreed the terms ex-ante. On one hand, load reductions are **voluntary for EDRP** participants while they are **obliged** under the **ICAP-SCR** program; in this case participants are paid beforehand. However there is **no direct control from the ISO to these loads**, the procedure consists on calling industries to notice them the guidelines. The prices paid in case of an event are the so-called **Locational-Based Marginal Prices (LBMP)** with a guarantee of minimum payments in case the hour price is higher than the market one.

It is important to mention that in any type of program it is **necessary to have real-time telemetry** with NYISO in order to measure and verify the load reductions bestowed.

On top of that, the **DADRP is a buyback program** that more or less works as described in the Types of Demand-Response Programs, where demand participants are able to bid their load reductions the same way generators do. The offers that are finally committed are paid at the **market clearing price**. This mechanism thus permits flexible loads to increase the supplied amount in order to moderate prices.

Lastly, the **DSASP** brings those customers capable of meeting some technology requirements the chance of bidding their load curtailment capability into either the day-ahead market or the real-time market aiming to **contribute in the Operating Reserves and the Regulation Service.** Accepted offers are also paid the clearing market price.

Regarding the state-of-the-art of NY, according to (NYISO, 2014), prior to the establishment of wholesale electricity markets, the electric system addressed growth in peak demand with comparable increases in generating capacity. Today, demand response resources can be used to shave the peak during periods of high demand. Large power customers and aggregated sets of smaller consumers participate in several DRPs developed in the NYISO markets. The **largest is the reliability-based Special Case Resource program**. In 2013, the program involved **more than 4,300 end-use** locations providing over 1,175 MW of load reduction capacity. 23 Participants in that program offered **1,189 MW** of capacity in the summer of 2014. The DR capacity available last summer 2014 is shown in Figure 29.

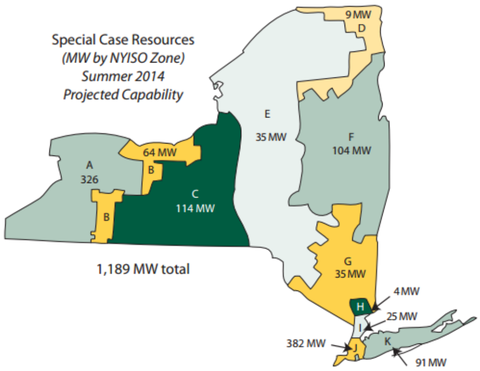

Figure 29. DR capacity available summer 2014.

NYISO

7.5.1. ICAP-SCR

According with Office of Energy Efficiency and renewable Energy, this mechanism brings **consumers larger than 100 kW** financial benefits to reduce their electricity consumption or use on-site generation along critical periods. Individual customers are obliged to participate through a RIP, Responsible Interface Party, which is in charge of coordinating the transactions within the NYISO. On top of that the **RIP is prohibited to commit the same resources in this program and in the EDRP program simultaneously.**

All customers enrolled in the ICAP-SCR capacity program are paid monthly the auction clearing price**, independently of whether the critical event is called or not.** To this availability payment, it follows another **energy payment,** in those cases where the event has been called, of **$500/MWh or market price**. In order to monitor the commitment of participants, **hourly metering is needed.**

ICAP-SCR Basics	
Capacity Payment	See bottom map
Energy Payment	$500/MWh or market price
Event Notification	Day-ahead and 2 hours prior real-time
Penalty for Non-Performance	Next like season's payment will be reduced based on non-performance or under-performance in the current season
Event Frequency and Duration	1 hour winter and summer, and two-three 4-6 hour events per summer
Who Can Participate?	Interruptible loads/stand-by generators

Table 11. Basic principles of the ICAP-SCR program.

7.5.2. Emergency Demand Response Program (EDRP)

This program has been available for longer than a decade in the New York area. Its principles are the same of the aforementioned ICAP-SCR mechanism, meaning that it consists on **load shedding mainly from industrial and commercial customers when Operating Reserves deficiency appears.**

However, contrarily to the SCR, the **EDRP is a voluntary curtailment program**, so there is neither obligation nor sanction for not attending the operator's request. Consequently there are not availability payments anymore and only energy finally curtailed is paid (per kWh). Other interesting specifications are shown Table 12.

EDRP Basics	
Capacity Payment	No
Energy Payment	Greater Real-Time MP or $500/MWh
Event Notification	Day-ahead and 2 hours prior real-time
Penalty for Non-Performance	Not apply
Event Frequency and Duration	4 hour minimum
Minimum Load Required	100 kW
Who Can Participate?	Interruptible loads/stand-by generators/aggregation

Table 12. Basic Principles of EDRP Program.

As it can be inferred from the description of the program, since the SCR is mandatory, the EDRP will be only used once all the available resources from the former one have been used. Therefore the utilization of this last mechanism is much lower.

Minimum Qualifications

To serve as a CSP (Curtailment Service Provider), an entity must:

1. Be a NYISO Customer (in the case of LSEs and individual retail customers enrolled as LSEs that take service directly from the NYISO to supply their own Load in the NYCA) or a NYISO Limited Customer (in the case of Aggregators and EUCs) and be able to pledge Load Reduction in the NYCA.

2. Be able to cause a Load Reduction from the NYS Transmission System and/or local distribution system at the direction of the NYISO.

• To be capable of reducing at least 100 kW of Load per zone.
• To be capable of responding within two hours of notice from the NYISO.
• Follow the enrollment procedures.
• **Provide hourly interval metering data to validate performance**.

Eligibility Requirements

An individual Demand Side Resource can subscribe to either EDRP or the ICAP SCR program, but not both. Special Case Resources (SCRs) that have enrolled with the NYISO but have not sold their capacity will be added to the list of EDRP resources for that period of time when their capacity is unsold, and will be called with EDRP resources if an EDRP event is deployed. To participate in the Program, **an individual Demand Side Resource cannot subscribe the same metered Load with more than one CSP. Information provided by CSPs may be shared with their local Transmission Owner** for planning or system operation**. Local Generators that are operating to fully serve their Load do not qualify for the EDRP**.

Compatibility with Other Programs

Demand Side Resources may participate in both the EDRP and the Day-Ahead Demand Response Program (DADRP) offered by the NYISO. If an EDRP event is called and a Demand Side Resource is participating in both programs**, payments will be made as follows**:

1. If the Demand Side Resource **has not had a demand reduction bid accepted** in the Day-Ahead Market for the day of the EDRP event, demand reduction provided as a result of the EDRP event call **will be paid in accordance with the rules set forth in the manual.**

2. If the Demand Side Resource is responding to the schedule determined from the **bid accepted** in the Day-Ahead Market, **payments will be made in accordance with the DADRP rules up to the demand reduction scheduled in the Day-Ahead Market.** Additional verified demand reduction above that scheduled in the Day Ahead Market will be paid in accordance with the rules set for the EDRP program. Demand Side Resources may participate in both the EDRP and the Demand Side Ancillary Services Program (DSASP) offered by the NYISO. **If an EDRP event is called and a Demand Side Resource is participating in both programs, the Demand Side Resource's dispatch schedule in the DSASP program will be terminated for the duration of the demand response event to permit the Demand Side Resource to participate as an EDRP resource.**

Small Customer Aggregation

1. **Aggregations must be at least 0.5 MW for EDRP.** Resources included in the aggregation may only participate in one NYISO reliability program.
2. **Aggregators will be held responsible** and liable for payments to and penalties levied against the members of the aggregation.

3. Small Customer Aggregation: The number of aggregations allowed needs to accommodate all of the utilities plus a reasonable number of CSPs and LSEs. Each initial proposal (or significant revision thereof) for small customer aggregation will be reviewed by the NYISO staff and the Price Responsive Load Working Group, and must be approved by a majority of the Chairs and Vice-Chairs of the Management Committee Business Issues Committee and the Chairman of the Price Responsive Load Working Group.
4. **The Small Customer Aggregator is responsible for all costs associated with developing and administering the alternative performance methodology.** The NYISO, in approving an application, will specify the costs associated with administration that the applicant must bear. The aggregation applicant must agree to be responsible for all such costs, including costs incurred by the NYISO for developing and administrating the alternative methodology. The NYISO may, at its discretion, require that some or all of such costs be reimbursed by the applicant upon approval of the methodology, or deduct all costs from payments for curtailments by resources, or a combination of the two methods of cost recovery.
5. End-use electricity customers may subscribe Load at a given premise to EDRP only under a single performance methodology, either the standard method or an approved alternative methodology.

Metering Requirements

As (NYISO, 2013) mentions, hourly interval metering data is required to validate performance. Demand Side Resources may use non-revenue interval metering devices with an overall accuracy of ±2% as the source of performance data. For each non-revenue interval meter design used, the CSP will submit certification from the meter manufacturer that the model in use meets the ±2% accuracy threshold, recognizing errors in:

- Current measurement.
- Voltage measurement.
- A/D conversion

7.5.3. Day-Ahead Demand Response Program (DADRP)

According with Comverge, the Day-Ahead Demand Response Program (DADRP) **enables energy users to bid their load reductions, into the Day-Ahead energy market as power plants do.** Offers determined to be economic are **paid at the market clearing price.** The program allows flexible loads to effectively increase the amount of supply in the market and moderate prices. Bids submitted by 5:00 am are scheduled as commitments for the next day at 11:00 am and the customer is notified at that time. There is no in-day notice.

How Does the Program Work?

Customers specify the hours of the next day they would be willing to reduce electricity use, the amount of that reduction, and the compensation required. That bid is submitted by the DADRP provider to the New York Independent System Operator (NYISO) **by a program provider**. The bid is then evaluated by NYISO and compared with supply bids submitted by generators. If a demand reduction bid is selected, or scheduled, NYISO expects the customer to reduce consumption during the appointed time. In turn, **the customer is paid the day ahead market-clearing price for the demand-reduction** amount scheduled. **If the customer does not reduce its load** as scheduled, **consumption during the scheduled curtailment is billed at the higher of the day-ahead price or the real-time price**. Payments by providers to customers for load curtailment bids may be lower as a result of administrative fees.

Eligibility Requirements

- **Minimum reduction of 1 MW** per facility in each hour of the bid. Aggregation allowed.
- Hourly interval meter is required to participate. Discounts on approved meters may be obtained through NYSERDA.

Bidding Specifications

- Amount of reduction.
- Start time and duration (so-called **strips**).
- Bid price. Some providers offer pre-specified strips.
- Curtailment Initiation Cost (CIC). The CIC places a floor on the total payment received if the bid is accepted, that is load reduction prices + additional amount.

Penalty for Non-Compliance

- Higher of the day-ahead price or the real-time price for the amount of the incomplete scheduled load reduction.

Baseline

- Penalty rates are applied to the difference between the Customer Baseline Load (CBL) assigned to each hour of the bid period, and its metered use in that hour. The CBL represents the customer's average level of use, during the time period equivalent to that of the curtailment bid period, during the **10 days prior** to the day the bid was submitted.

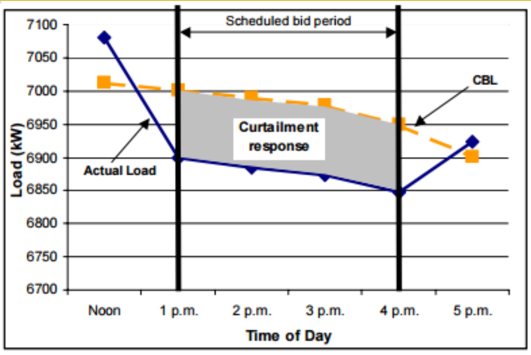

Figure 30. DADRP CBL methodology. Source: NYISO.

7.5.4. Demand-Side Ancillary Services Program (DSASP)

Current rules regarding DSASP are in place since 2009. The "reserve" program's aim is to keep a certain **reserve of energy on the NY grid for the case that a power plant or line goes down.** As shortages of this reserve are not necessarily weather driven, the events occur year round. However, the **events** are much shorter than traditional demand response events – **lasting only 5-12 minutes**. **You will have a choice of 10-minute or 30-minute event notice** (with different payments for each), thus **building automation is essential.** Some of the characteristics of this program are listed below:

- All Ancillary Services open to DR
- Minimum requirement: 1 MW sustainable for 1 hour (Reserves)
- Communication: Leased line to aggregator
- Telemetry: Real-time from aggregator ICCP to NYISO and utility, regulation must respond to 6 second AGC signals
- Aggregators communicate with resources via internet-based protocols.
- Following Order 719 of FERC

Barriers

- Burdensome and expensive metering and communication requirements ($50-100k/site)
- Aggregations not yet permitted
- Full integration with energy market means A/S dispatches are economic, not event-based
- No energy payment until new real-time economic program implemented
- **Network latency may impede aggregators participating in regulation markets if response of aggregators to NYISO data must comply with 6 second AGC scan rates.**

7.5.5. Comparison among NYISO Programs

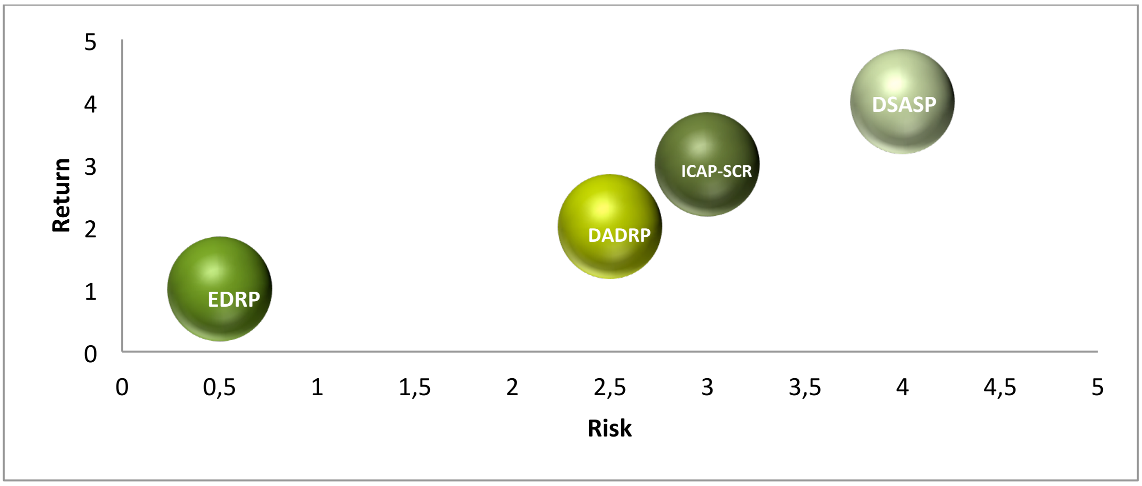

Figure 31. Risk/Return Comparison of NYISO Programs.

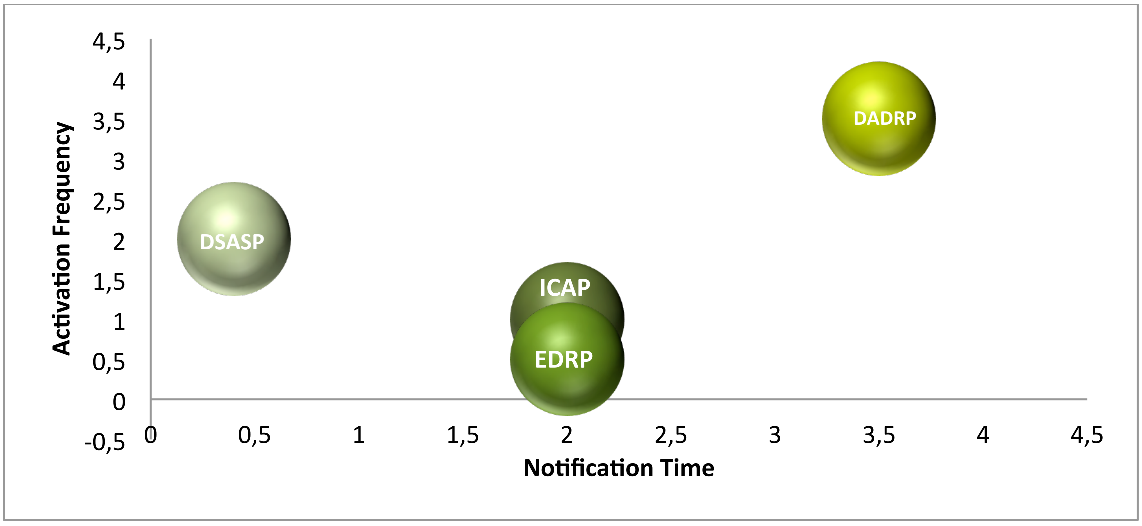

Figure 32. Frequency/Notification Time Comparison of NYISO Programs.

Low Risk Low/Moderate Return Non-Guaranteed Activation No payment without Activation	Moderate Risk Moderate/High Return Payment Regardless of Activation Non-guaranteed Activation
Moderate Risk Moderate Return Scheduling Based on Bids	High Risk High Return Scheduling Based on Bids

Con Edison Programs

As it is mentioned by Con Edison, Con Edison's demand response programs pay **over 800 participating customers** who are able to temporarily reduce electric usage when requested by this very same company. The DR programs offered are for commercial, industrial and residential customers. The possibilities are:

- **2 Hour or Less Notification Program (Distribution Load Relief Program)** and upon request reduce their electric usage to help maintain system reliability in their communities.
- **21 Hour Notification Program (Commercial System Relief Program)** and upon request provide load relief for Con Edison on the hottest days.

Both the 21 Hour and the 2 Hour Notification Programs have a Reservation Payment Option and a Voluntary Participation Option. A customer can participate in one option in either one or both programs.

- Customers who enroll in a **Reservation Payment option** will receive monthly payments based on the amount of energy they have pledged to reduce upon request. These customers receive additional payments for actual load reduced.
- Customers enrolled in the CSRP or DLRP **Voluntary Participation option** only receive payments if Con Edison requests and they reduce energy. These customers receive **$3.00 for each kWh reduced. Customers in the Voluntary Participation Option** do not need to participate in a test event.

7.5.6. Distribution Load Relief Program (DLRP)

DLRP participants provide DR through load reductions or operation of on-site generation when Con Edison determines that the next system contingency would result in a Condition Yellow, or if a voltage reduction of 5% or greater has been ordered

- Condition Yellow exists when the next contingency (excluding breaker failure) either will result in an outage to more than 15,000 customers or will result in some equipment being loaded above emergency ratings.

The payments for those customers enrolled under the **reservation payment option** will receive **$6.00 per kW per month and $1.00 for each kWh** that is reduced during an event if they are located in a Tier 1 network. Customers located in Tier 2 networks will receive **$15 per kW per month and $1.00 for each kWh** that is reduced during an event.

7.5.7. Commercial System Relief Program (CSRP)

All types of customers are eligible to participate in this program. It is also available to **aggregators who contract to provide at least 100 kW** of load relief in one or more networks. It is only available in New York City area.

Participants under the Reserve Payment Option receive **$10.00 per kW per month and $1.00 for each kWh** that is reduced during an event. Furthermore customers with loads greater than 250 kW are required to provide a minimum of 10 kW of load relief.

Requirements for DLRP and CSRP

- Customers enrolled in the Reservation Payment option are required to participate in a one hour test event per program every year.
- Customers must **maintain electric reduction for at least 4 hours** during non-test events.
- Con Edison may issue requests to reduce usage **between May 1 and September 30**.
- **CSRP** Customers must be able to respond to demand response events **Monday – Friday** and during the call window of the network they are located in.
- **DLRP** customers must be able to respond to demand response events from **6:00 AM to 12:00 AM any day of the week**.
- Energy usage reduction during the test and all events is measured using the Con Edison's Customer Baseline Load procedure.
- Aggregators must have in place systems and processes in place to:
  - Respond to demand response events pursuant to notification through Con Edison's prescribed notification system.
  - Ensure that enrolled customers respond to demand response events within demand response program specific time periods.

Restrictions

The 21 Hour Notification Program has a **limitation on Distributed Generation (DG)** and exclusion of DG other than renewable resources that are within a half mile of certain electric generators. The New York State Department of Environmental Conservation maps show the geographical areas where DG is prohibited from being used in the 21 Hour Notification Program.

The statistics given by Con Edison have shown that although lonely enrollment of end-users in DR programs is allowed, 96% of participants access the system through aggregators thanks to their management platforms and operation, which makes participation easier.

7.5.8. Conclusions and Recommendations

According to all the regulatory information detailed before, we have proceeded to summarize it to end up giving some future recommendations. This abstract is shown in Table 13:

Consumer Access	- Wide variety of ways to access to DRPs via aggregators, directly, through distributor and retailers… - Large number of aggregators. - Access to most ancillary services. - No need of entrance fees. - Only two entities allowed to offer DRPs: NYISO & Con Edison	B+
Program Requirements	- ICAP-SCR: 100 kW, availability. - EDRP: interval metering, 100 kW, compatible with other DRPs. - DADRP: 1 MW aggregations, high penalty for non-compliance. - DSASP: expensive equipment required, not aggregation permitted, 1 MW curtailment required. 6s response needed	A-
Measurement & Verification	- Aggregators may do the tasks of M&V on customer's behalf in case that it is their choice.	A
Finance & Risk	- LBMP paid in the variable term generally. - There is a spread variety of programs that allow participants to bear different grade of risks so that they may opt for higher remunerations. - Costs are allocated accordingly to flexibility offered and energy reductions committed.	A
Overall	A	

Table 13. New York's grades

Generally speaking, NY can be considered one of the most advanced power systems regarding the implementation of DR resources in the world. It not only permits free and easy entrance to almost every kind of customer but also it offers a wide variety of products to adapt demand both in the day-ahead and in the ancillary services markets under relatively reasonable conditions.

However, although NY shall be seen as an example for other power systems to implement DR effectively, there is always margin to improve. Therefore some brief recommendations that have been detected along this study process are listed below:

- Permit future DRP offers of third-party entities. Only two actors play this game so this can distort competition.
- Launch measures to give robustness to the DSASP in order to let residential and commercial small and medium loads to get part of it as an aggregated way. The main hurdle is the 6 seconds response requirement.
- Same for DADRP, since both economic programs lack of participants. More flexible measures should be considered in the long-run to increase the acceptance of such programs.
- As in the rest of systems, educational campaigns are a must to increase the number of participants. Once prices, penalties and other features are properly set, the rest is about make customers aware of the potentiality of DRPs.
- Need regulatory convergence between retailers and wholesale markets. Rules and incentives for both parts.
- Need of stronger market rules protecting Distributed Resources.
- Data integration. Larger investments and perhaps subsidies to ITs is a must to increase the number of participants. For instance, demand-side automation, intelligent monitoring device…

7.6. California

Background

California is a leading State within the U.S. in terms of innovation towards integration of renewable resources and implementation of a variety programs aiming to enhance efficiency and proportionate a modern and green electric power system to its inhabitants. Though there have been many efforts and trials to make demand a strong and important participant in the wholesale markets, this is not the case yet as the participation and outputs set have not been reached and some programs have only behave as a mere trial.

As a background for the further study, the production mix of the Californian system is shown in Figure 33:

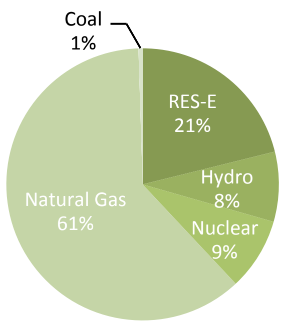

Figure 33. Production technology mix. Source: California Energy Commission,

The average annual production in California remains about **200.000 GWh** from an installed fleet of **80,000 GW**. As it is seen a vast majority of the power produced in California comes from CCGT plants, which broadly speaking are operationally more expensive than other technologies and very flexible since they are able to work with high ramping curves in relatively short periods of time. Besides, the Californian power sector is characterized for being one of the power systems across the U.S. with more integration of RES. These two issues can lead to misunderstand what the aims for enabling Demand Response are.

It could be thought that the main benefit DSR brings to the system is flexibility, in other words, capability to relief the network under stressed conditions. Moreover, as natural gas plants are extremely flexible it might be reasonable to think that they should be the ones committed to provide this pursued relief to the system.

However the other characteristic of NG plants is **expensiveness**, which leads California to be one of the most expensive States along the U.S. in terms of electricity tariffs paid by consumers. This information is provided by U.S. Energy Information Administration. On top of that, the high amount of renewable resources spread mostly residentially crosswise, makes DSR an appealing figure to permit a full implementation of these uncertain resources.

Hence, reducing energy prices and integrate RES are the two principal reasons on why DSR are gradually being taken into account in the CAISO system.

As stated by the California Energy Commission, the state's main challenge is to ensure adequate electricity supplies while reducing greenhouse gas emissions as directed by AB 32 (33% reduction by 2020). Since 2003, California's energy policy has recognized an electricity "loading order" as the preferred sequence for meeting electricity demands. **The loading order lists energy efficiency and demand response first**, **renewable resources second, and clean and efficient natural gas-fired power plants third.**

In addition, under the Renewables Portfolio Standard, California's goal was to increase the amount of electricity generated from **renewable energy** resources to 20% by 2010 and in 2011 legislation passed to push that goal to **33% by 2020**.

Demand Response Status

California has an extensive history with demand response programs, which were well-received by energy customers as early as the **1990s**. But the programs were not triggered often by utilities before 2000. The importance of demand response programs in California's energy policy increased in 2003, when the state's **loading order** was established by the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and the California consumer Power and Conservation Financing Authority.

In 2003 the **CPUC set the goal of meeting 5 percent** of the system's annual peak energy demand through demand response programs **by 2007**. This goal was applied to "nonemergency" demand response programs (non-interruptible programs), and as of spring 2014, California was slightly more than halfway toward meeting that 2007 goal.

There are a variety of residential and non-residential programs **offered by PG&E, SCE, and SDG&E**. Some utility Demand Response programs are arranged by third-party operators also known as "Aggregators" or "Demand Response Providers." Demand Response programs offer incentives to electricity customers to reduce or shift energy consumption. These reductions occur as Demand Response 'events.' During these events customers are asked, or are remotely signaled, to shed load due to reasons such as high-energy prices and/or system reliability is threatened. According to FERC the actual **potentia**l of California regarding DR capacity to be managed is of **2.270 MW**, which represents about the **5% of the average peak demand**.

According to (Energy Environmental Economics, 2014), over-generation of energy is acknowledged as the major renewable-integration problem for a higher renewable-energy portfolio standard in California. The study declares that DR could reduce the impacts of over-generation and ramping, but advances in DR are desirable to enable for upward and downward modifications.

In 2012, CPUC found that they "underutilized DR programs and **dispatched their power plants to meet peak demand far more frequently in comparison to DRPs**. Such programs were not used to their full Resource Adequacy capacity, even during extremely hot weather circumstances. "CAISO also has not been turning to utilities' DRPs as a resource to meet real-time grid needs, except as a last resort.

Californian utilities devote important quantities of ratepayer funds on the state's DRPs but the **benefits to ratepayers are still unclear**. The potential for a utility to reduce energy demands by activating a DRP does not outcome in ratepayer benefits if the energy reductions do not avoid ratepayers' generation costs.

DRPs must demonstrate:

- Avoid use of higher-cost energy generation
- Avoid construction of traditional PPs or transmission networks
- Improve integration of RES
- Lower energy costs for customers

The CEC, CAISO, and CPUC are revising California's DRPs and shaping them into two categories: **supply-side resources and load-modifying programs.**

According to the Demand Response and Smart Grid Coalition, **100 hours** of peak-demand usage nationwide **accounts for 10 to 20** percent of the US cost of electricity every year. In 2012, CAISO had 2.430 megawatts in demand response resource potential—the fourth most of any ISO and RTO in the country. Grid operators PJM Interconnection, Midcontinent Independent System Operator, and ISO New England all had more megawatts and a larger percentage of peak-demand resource potential than California.

The council also found that larger companies were much more likely than smaller companies to participate in demand response programs, primarily because of a lack of awareness and lack of education about program benefits.

In 2011 the CPUC adopted a decision prohibiting Resource Adequacy program credit for demand response programs that use fossil-fuel backup generators. As other states change rules and require more data about performance and other factors, participation has declined.

However rules are changing in California. On September 19, 2013, the CPUC adopted an order instituting **rulemaking to attempt to address troubles** revealed by the implementation of DRPs, nonetheless it remains to be demonstrated if those rules are effective. Moreover, the CPUC launched the Electric Rule 24 that sets the main rules to **let DR to participate in CAISO's wholesale markets**. And last February 2015, CPUC issued a proposed decision that set the first-ever budgets and targets for how the 3 issued State utilities shall bring customers into DRPs. This is shown in Table 14.

TABLE 7 REQUESTED PHASE 1B BUDGETS (PRESUMES CAISO'S LOCATION API)		
UTILITY	PARTICIPATING CUSTOMERS	REQUESTED BUDGET[115]
PG&E	10,000	$2.9 million
SCE	14,000	$2.7 million
SDG&E	7,000	$300,000 + unknown IT costs

Table 14. Targets and budgets of DR providers.[8]

According with (St. John, 2015) the proposal might allow the 3 utilities to recover costs for the technology platforms and business processes that could make direct participation in DR possible. Moreover, DR have had opened the doors of wholesale markets somehow, but

[8] Unknown IT costs finally set at $1.5 Millions.

bundled customers have not been able to bid into the wholesale markets. **This is what Rules 24 and 32 are going to permit.**

Finally, as stated in (Walton, 2014), bill SB 1414 was signed by California's Governor Jerry Brown in September 2014 obliging the power sector to include DR in the adequacy planning and maintaining, enhancing and creating old and new DR programs.

7.6.1. Experiences

The **CPUC** approves ratepayer funds allocated to DR for 3-year periods, and approved nearly **$1 billion** for the last 3-year cycle, from 2011 to 2013. The other main state funding for DR came from the **CEC**'s Public Interest Energy Research funds. According to them, it has awarded more than **$22 million** since January 2005 to DRPs, more than half has gone to the Demand Response Research Center at Lawrence Berkeley National Laboratory.

This same laboratory developed a communication infrastructure called **Open Automated Demand Response (OpenADR)**, which provides a uniform protocol for aggregators, utilities, and energy users for sending signals about energy use and management. In 2007 the CPUC required California's three investor-owned utilities to offer OpenADR-based programs.

The roster of DRPs offered in California is:

- Aggregator-Managed Programs
- Agricultural and Pumping Interruptible Program
- Air Conditioning Cycling or Reduction
- Automated Demand Response (Auto-DR) Programs
- Base Interruptible Program (BIP)
- Capacity Bidding Programs
- Demand Bidding Programs
- Peak-Time Rebates or Critical
- Peak Pricing
- Time-of-Use (TOU) rates

Some DR programs are embedded within other ones to make a DR system. For instance, those customers enrolled in programs that require Auto-DR technology are offered financial incentives to use such technology. **Auto-DR** is an example of the devices needed to meet the requirements of certain DR products, and it consists on wire or wireless tools that are able to **control** the dimming of the lighting system, adjust the AC machines and so on and so forth. It may also include software to manage specific energy systems.

California's DR programs are **divided** into those that permit participants to be notified either one **day ahead or the very same day of the need.** Note that there is an initiative called **Flex Alert**, which seeks to **educate** public about the need of energy conservation in the summer period.

7.6.2. Base Interruptible Program (BIP)

It is the largest DRP in place, and it basically consists on making **payments to large industrial customers** to curtail load when called by the utility. As stated by (California Senate Office of Research, 2014), BIP has been used only in **7 events in the last 9 years**. This program spent a budget of **$837 million** over the last 9 years and accounted for **36% of the ratepayer funds** assigned to DR mechanisms.

However, although BIP is not frequently used, the events called have shown its usefulness as for instance during a test run in the Southern California Edison (SCE) territory, which curtailed **573 MW**, equivalent to feed around **118.000 households**. This order of magnitude means **three times** the curtailment capacity of any other DR program.

The current situation of BIP is that utilities only activate the program as a last resort option, after the TSO CAISO calls an emergency event.

Policymakers might question if more than one third of the ratepayer funds for DRPs should be assigned to BIP, which **barely gives real benefits to customers**. Or maybe they should **modify the program** so that it can be activated more often giving more significant reductions.

PG&E's and SCE BIPs	
Capacity Payment	Yes, $8-9/kW
Energy Payment	
Event Notification	30 minutes in advance
Penalty for Non-Performance	$6/kWh
Event Frequency and Duration	Max. duration: 6 hours 1 event/day; 10 e/month; 180 h/year
Minimum Load Required	Average Load Demand 200 kW Availability to curtail 15% of Average load demand Firm Service Level (FSL)
Who Can Participate?	Large Industries (Third –party aggregators permitted)
Equipment	Remote Electric Interval Meter

Table 15. Targets and budgets of DR providers.

Participants receive **monthly bill credits** based on the difference between your average peak period kilowatt (kW) demand for each month and your FSL. Credits vary depending on the season, time of day (on-peak or mid-peak), voltage level and other factors, and credits apply whether or not TOU-BIP events are called in a given month.

BIP customers may also enroll and participate in other Demand Response programs to earn additional credits. More information regarding the BIP program can be found at SCE and PG&E.

7.6.3. Peak Time Rebates and Critical Peak Pricing

During the hottest months, when energy use hits its peak, prices are also at their highest. Hence business can save money and help relieve demand by voluntarily reducing energy consumption or shifting to off-peak hours during such events. In this concern the products offered by the 3 different suppliers of DRPs are going to be summarized in Table 16.

	PG&E	SCE	SDGE
Program's Name	Peak Day Pricing	Summer Advantage Incentive	Critical Peak Pricing
Number of Events	9-15/year	12/year	18/year
When	Year-round	Year-round	Year-round
Duration	2-6 pm	2-6 pm (no holidays)	11 am-6 pm
Warning	Day ahead	Day ahead	3 pm day ahead
Eligibility	Res, Comm & Ind	Res, Comm & Ind	Res, Comm & Ind
Tariff Sheet	Link	Link	Link

Table 16. CPP rates in CAISO system.

A brief explanation on how the program works is given in the next figure, where typical ToU rates are applied and when PG&E or CAISO calls for an emergency event prices raise in order to encourage customers to stop consuming.

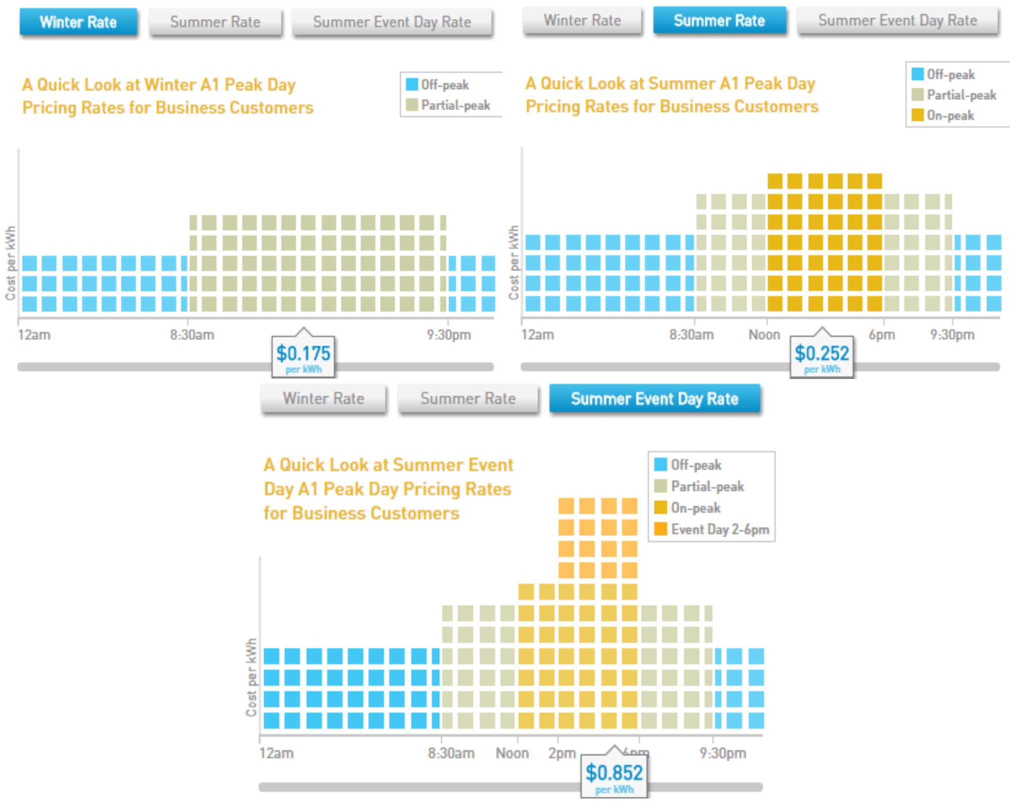

Figure 34. PG&E's CPP Tariff.

The practical experience shown in the implementation of these mechanisms arose that very often utilities **fail to communicate** customers about the events, as CPUC states.

On top of that in 2012, which is the last period with full data recorded, in the SCE territory, 95% of the overall incentives paid within this mechanism were given to customers that either were **not aware of curtailing load** in the required periods or did not do it significantly if they were aware, agreeing with the CPUC.

7.6.4. Air Conditioning Cycling or Reduction

These initiatives are opt-in programs that give customers rebates or discounts for permitting utilities to manage or adjust their AC machines during critical peak periods, so that the grid can be slightly relief under stress conditions.

PG&E's Approach. SmartAC Program

When the system is activated, the temperature in your business will **never be raised more than four degrees**. Because it's automatic, subscribers do not have to do anything and most customers do not even notice when it happens. The program also gives flexibility to participants due to the fact that **users can refuse to participate** for the day if the event is called at an inconvenient time.

SCE's Approach. Summer Discount Plan

If SCE calls an energy event in response to emergencies due to high wholesale energy prices, or as part of testing, the utility turns off (or cycle) the selected A/C's compressor(s). These events may be called **year-round**. The remotely-control device is installed **free of charge**. The different tariffs available are shown in Figure 35.

Figure 35. Cycling SCE's options.

SDGE's Approach. Summer Saver Program

Summer Saver is only used May through October. It may be used as little as one or two days, but will **never be used more than 15 days**. To qualify, customers **can not exceed usage of 100 kW** at any point in a 12-month period. Therefore this program is done for **residential and small or medium commercial** consumers.

In this case SDGE offers two options, the 50% cycling and the 30% cycling. The bill credit is based on the tonnage of each AC system. At **30% cycling**, you are paid **$9 per ton**. For example, if you have a 5 ton system, you credit would be $45. For **50% cycling**, you are paid **$15 per ton**. For a 5 ton system, you'd earn $75. According to SDGE, one ton is 12,000 BTUs of cooling/hour. On average, one ton will cool from 400-700 square feet in a residential application and about 1,000 square feet in a commercial application. SDGE has an agreement with a third-party, Comverge, Inc. They are responsible for installing, removing and servicing the wireless unit.

Overview

As an analysis, (California Senate Office of Research, 2014) found that most of participants complained about having **excessive hot temperatures** inside their buildings. This is an example of a managing solution that does not fit with real necessities. Besides, a **"rebound effect"** was detected as a consequence of having AC machines shut-off during periods of time of about 2 hours. This effect provoked that AC consumption was much greater after the event was called since users employed way more energy to re-adjust temperatures, which in the end **neglects the benefits** brought by the program.

As a way on how to approach this problem, PG&E's **SmartAC** program does not shut-off AC machines as other programs do. Instead, **thermostats are adjusted** a few degrees during peak-use periods and therefore if these adjustments are done in the right way, they might help to eliminate the aforementioned rebound effect as temperatures would be more comfortable.

7.6.5. Demand Bidding and Capacity Bidding Programs

These mechanisms consist on allowing **nonresidential consumers** to bid the amount of energy they are open to reduce in response to a DR event. The main difference between them lays on the notification and the bid times and of the penalties.

Demand Bidding Program (DBP)

It notifies agents **one day ahead** the event takes place, with **no penalty for underperformance**. Compensations follow a **kWh** reduction basis. Contrarily, although **capacity bidding programs** also receive kWh payments, they also receive **capacity payments** regardless on whether the event has been called or not. The main features of the SCE's demand bidding program are:

- Events are called Monday through Friday, excluding holidays between noon and 8 pm.
- Notifications take place around noon the day before a DBP event Then bids will be accepted (from noon to 4:00 p.m.) for the amount of demand each participant is willing to reduce the following business day
- Minimum bid required of **1 kWh** and reduce energy use/demand for at least **two hours** within that window. Credits will be given for actual load reductions that are 50% or greater and up to 200% of your hourly bids. In case of placing a bid and reduce energy use during the event, you'll receive bill credits based on the difference between your 10-day hourly average usage (excluding weekends, holidays and other event days) and your actual hourly usage during the event.
- Bundled-service customers can receive a bill credit of **50 cents per kWh** of actual power reduction
- Direct Access customers may be eligible to receive a bill credit of 50 cents per kWh of actual power reduction minus the CAISO's hourly average energy price

- **Eligible customers** are grouped in non-residential SCE Bundled-service, Direct Access (DA) or Community Choice Aggregation (CCA)
- A meter capable of recording usage in **15-minute intervals** is a need as well as capability to reduce a minimum of **1 kW** for at least **two consecutive hours**

The product offered but the rest of providers do not vary too much from the one given by SCE. The route map is the same and only some details change, as for instance the PG&E's 10 kW minimum bids.

Capacity Bidding Program (CBP)

According with PG&E's program, it is an aggregator managed mechanism that is available from May 1st to October 31st, that are the hottest months of the year and during which extreme conditions in the grid are expected to occur. It is **offered one year in advance** and it is managed by one of the licensed aggregators. Each one is accountable of offering their own CBP as well as other side services.

These kinds of programs are focused on business of all sizes that bid part or all their capacity during scarcity periods. As all the CBPs offer by the three big utilities are pretty similar, only one of them will be explained since only details change comparing with the others. In this case the methodology applied is explained for the SCE's program.

As mentioned before, CBPs are **event-based,** that typically happens from 11 am to 7 pm. Each month, businesses **select in advance the quantity they are willing to reduce** during such periods. In exchange, businesses receive **incentive payments to meet their bids**. On top of that, the same way as in other programs, CBPs usually include **capacity payments** in exchange of availability. The duration of the events last **8 hours** and can be called either one day-ahead or on the very same day. The limits for participants are **1 event per day and/or 30 hours per month.**

Participation is subject through third-party aggregators or self-aggregation in certain cases. CBP is **open to non-residential customers of all sizes**, so there is **no minimum monthly demand to qualify.**

Rates for the program describes can be found in the website, but a hint of how CBP is paid in the day-off option is shown in Figure 36.

Day-Of Option - Capacity Credit Rate ($/kW-month)

Hours per Day	Jan	Feb	Mar	Apr	May	Jun
1 to 4	1.55	1.29	1.29	1.29	3.11	4.66
2 to 6	1.90	1.58	1.58	1.58	3.80	5.69
4 to 8	1.90	1.58	1.58	1.58	3.80	5.69
	Jul	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
1 to 4	15.79	18.38	9.84	1.81	1.55	1.55
2 to 6	19.29	22.46	12.02	2.21	1.90	1.90
4 to 8	19.29	22.46	12.02	2.21	1.90	1.90

Figure 36. SCE's Day-Of CBP capacity rates.

7.6.6. ToU Rates

Californians shall sign a **ToU rate and at the same time participate in other DRPs**. The legal background in this concern changed in 2013 when (State of California, 2013) set the new conditions and features that ToU rates would contain. Such Amendment deleted the in-force restrictions and allowed PUC, starting January 1st 2018 to authorize or require any Investor-Owned Utility (IOU) to offer and use default ToU rates for residential customer.

From now on, IOUs offer voluntary ToU tariffs for both non-residential (most common holders) and residential customers. As an example, PG&E **SmartRate tariff** offers:

- **3 to 4 cents/kWh** reduction from June to September.
- Event periods raise prices by **60 cents/kWh.**

According with (California Senate Office of Research, 2014), as of spring 2014 there were approximately **120.000 participants** in PG&E's SmartRate program (there are about **5.3 million PG&E electric customers** in the state). This stands for **less than the 3%** of eligible customers.

7.6.7. Conclusions and Recommendations

As CPUC addresses, DR is not implemented in the CAISO's wholesale energy markets yet. As a consequence when utilities call for DR events, usually **CAISO is not aware that DRPs** can be used to manage an emergency. This is a clear handicap as DR is not yet used as a tool to keep the grid stable.

The aforementioned BIP program is by far the most expensive and important mechanism in terms of participants and capacity. However **BIP is used hardly ever.** In addition, certain programs **pay customers for involuntarily reductions** and in other occasions, when reductions are made on purpose, there is a latter **rebound effect** which neglects the former benefits brought by DRP's activation. Another key issue is that the lack of coordination between CAISO and utilities causes that **DRPs are not used to balance the grid.**

According with (California Senate Office of Research, 2014), on September 19, 2013, the CPUC adopted an order instituting **rulemaking to attempt to address troubles** revealed by the implementation of DRPs, nonetheless it remains to be demonstrated if those rules are effective. Moreover, the CPUC launched the Electric Rule 24 that sets the main rules to let DR to participate in CAISO's wholesale markets. The potential is perceptibly enormous as any user who owns a Nest thermostat or any newly curtailing device would be able to **bid directly into the markets** as any other conventional resource. However utilities want all DR to be controlled by them so an open-field battle arises. The final status given to California concerning DR is shown in Table 17.

Consumer Access	- Although some DRPs only allow large industries to participate, most programs permit small residential customers to enroll - Aggregation permitted and efficiently implemented - 3 utilities allowed to offer DR programs but likely to change - All markets opened to DR	A
Program Requirements	- Low use of DRPs (BIP) though very useful when used - Some DRPs require too long availability periods (4-6 hours), Peak Pricing) - Wrong-planning, as shown with rebound effects in Summer Saving Programs	B^-
Measurement & Verification	- Demonstrated lack of communication between utilities, customers and CAISO - People not aware of being curtailed in some DRPs - Large quantity of IT systems already deployed	C^+
Finance & Risk	- Payments done to people not aware of being participating, not cost-effective - Most DRPs are free of access charges - Reasonable penalties for underperformance in the case they exist - Some DRPs do not give real benefits for customers	B^+
Overall	B/B^+	

Table 17. California's Grades.

Recommendations

- Monitor actions modifying DRPs by CAISO, CEC, CPUC and utilities, and do a follow-up of any approvals required by FERC.
- Prevention of mistakes made in the past, avoiding programs that do not bring the benefits of consistent load modification or the responsiveness of the supply side resources. DRPs must be cost-effective and they have to be appealing to provide more participation.
- Oblige CPUC and CAISO to report to the California State Legislature on the implementation of the prior mentioned Electric Rule 24.
- Require CPUC to assess aggregators to perform best practices to enhance performance.
- Oblige some DRPs to demonstrate their capability to adjust power upwards and downwards in order to better integrate RES-E.
- Launch educational campaigns teaching residential customers on how to use their electricity efficiently, making use of peak-period prices without jeopardizing their comfort, as ToU tariffs might become mandatory.
- Updated CPUC's goal of meeting 5% of the system's annual peak energy demand using DRPs by year 2007. To set new goals, define ex-ante what the programs should accomplish when modifying loads or providing demand reductions as any other traditional resource in California. Bottom-up approach.
- Utilities might provide data to settle transactions favored by smart meters rather than from specialized meters used for today's DRPs. **Standardization** of technology. See **"Supply Side Pilot"** to be ran next August.
- Another recommendation, which will be tested this year by PG&E on its program Excess Supply Pilot (XSP), is to permit demand to **absorb excess production** from solar and wind PPs so that it does not have to be curtailed. This might bring DR the

possibility not only of reducing/shifting load but also increasing their consumption as a network tool.

- CAISO need to create application-programming interfaces (APIs) to allow utilities to integrate their IT platforms into CAISO's platforms.
- California should decide on whether to go for market-based DR programs or if they want to go for command and control options. The work done has a mix of both options so **signals sent are blurry** thus preventing new investment.

According to (St. John, 2015), CPUC recommended starting the **DRAM program** aiming to make demand response to participate in a market to meet the adequacy requirements of the grid in the forthcoming years. This basically the same methodology followed by PJM and that has become the largest demand response market in the world.

The first DRAM auction is set for late 2015, and will be committed to meet traditional system adequacy needs for 2016. The second, to be held in 2016, will also ask for **flexible capacity** mainly to deal with the **"duck curve"** issue very common in California and which consist on steep ramps in energy demand when solar PV systems are dumping energy into the grid.

It is important to note that DRAM does not initially have a **cap** like other direct DR programs. Hence the **quantity provided** by participants will be crucial to determine whether to move or not the majority of DR initiatives to this new model in the years to come.

8. Conclusions

This chapter gathers the main concepts concluded from the analysis of each country to improve and encourage the correct development of DR options according to the special characteristics of each system. On each of the topics, a brief description on how to face the problem will be described.

Moreover, once local recommendations are deployed, the section will give a description of the main guidelines to be followed from a broader point of view to embrace demand-side participants within the electricity wholesale markets in a fair and equitable way, where DR can compete with traditional power sources.

Spain

Need to organize high-level discussions regarding the Energy Model

As mentioned, there is around a 73% of overcapacity, most of it formed of CCGT power plants with a lot of flexibility. There is also overinvestment in network infrastructures so two of the main benefits that DR brings are not interesting to the Government nowadays. All of the energy policy is committed to reducing the tariff deficit. Therefore it would be recommendable to discuss the gradual and efficient introduction of DRPs (especially flexible tariffs) to at least allow customers to be aware of their potential and help them to reduce energy bills.

The functioning of Mechanisms such as the Interruptible Load Service are questioned

The Government and the Spanish TSO 'Red Eléctrica de España' might rethink the objectives of this program. As commented overpayments to large industries are a fact and the utility of it to relieve the grid is being questioned as it is used two/three times per year barely. Some sources point out that the existence of cross-subsidies have nothing to do with electric power systems. Auctions are not well defined, as there is not a clear schedule on when to participate or how many auctions are going to be held each year.

Define Aggregation legality and responsibilities is a must

Aggregation is not legal in Spain. One of the explanations given to permit it is that aggregation may lead to physical evasion, that is users paying less network charges, as they should. However, international experiences have proven that if the roles of each counterparty and the limits are well defined there is no problem aggregating even small residential loads. As we also noticed in this document, aggregation is crucial in DRPs development and for the number of participants since smaller ones are not able to compete with larger industries or business without summing forces together.

Incentivize participation in DRPs

To make customers enroll, clear signals need to be sent to them in order to make them aware of the benefits they can obtain and in the suitability of such DRPs. This is to say that a larger number of alternatives according to the different type of customer may be available. For instance the 'Discriminatory Tariff' defines peak periods of 10 hours per day. This is not very attractive for customers and it might also lead to misunderstandings, as it is not clear when to shift load.

Define rational penalties for non-compliance

As identified in the interruptible load service, some penalties account for the total remuneration of one year for non-compliance or underperformance. This should be remodeled and set clear ceilings that incentivize customer to participate but do not transmit fear so that they do not enroll.

Access to information

New platforms and processes are vital to having all the information regarding your self-consumption patterns. Moreover if aggregation is finally legalized it would be important to redefine rules to transfer information between BRPs and BSPs when requested.

Need information campaigns

It is an issue that may sound useless, but electricity is seen as something complex and strange for the vast majority of consumer. Therefore it would be very important to give basic information on how customers can use their flexibility and how can they benefit.

There is still some optimism

Although the rate given to Spain is very poor and the country clearly needs a battery of measures to get to a fair situation for DR, the obligation of having 100% smart meters by 2018 and the new hourly basis billing in some regulated tariffs gives some hope on that the situation could change.

France

Aim to reduce expensive balancing solutions

As it was concluded the high number of nuclear production in France makes DR an appealing actor to reduce costs of balancing services and a way to avoid nuclear power plants to change their production in short periods of time.

Permit aggregation in more than one region

If France wants to increase the number of participants in DRPs and make the market more liquid, one measure would be to allow national aggregation, contrarily to the zonal permits that are working nowadays. Although network constraints are the main reason of this limit, aggregation could be efficiently managed nationally but operated regionally.

Modify the Frequency Restoration Reserves Capacity Requirement

Although this program may not be feasible for small residential customers yet, it has been identified that reducing the minimum load requirements from 10 MW to 1-5MW helps to increase exponentially the number of businesses and small industries enrolled in the FRR. Not only load constraints shall be revised but also financial aid or standardization processes for IT technologies on this matter should be taken into account.

Time Disposition Requirements for Frequency Restoration Reserves

The same problem argued in the previous point occurs in terms of the time window availability required. The requisites are thought for traditional power stations that have the sources to commit 24h availability of curtailing/increasing consumption but not for smaller industries or business. Therefore and effort must be done to design rules that treat fairly demand-side participants in the ancillary service markets. The proposal given in this study is going for 2/5-hour availability windows with proportional remuneration schemes.

The Capacity Market will determine the future of DR

In order to start running by 2016, the new capacity market in which DR is included will be key to see if the rules to enclose DR in the future planning of the grid are appropriate. This document supports the idea of giving the option of purchasing explicit or implicit certificates accordingly to the particular interests of each agent. Closer to real-time auctions and payment, methodology will determine the success or failure of this option.

Market Prices do not reflect flexibility enough

Real-time and day-ahead prices are too similar to be appealing for small customers as they do not find it worthy to participate in DRPs. The recommendation here is to study the possibility to oblige retailers/aggregators/BSPs to buy explicit certificates according to their peak consumption portfolio.

Great Britain

Time and Load Requirements for Frequency Ancillary Services

The issue is the same as mentioned previously for the French frequency response reserves. If smaller industries and business are seeking to take part in the programs, then narrower availability windows and minimum load curtailed are essential.

Try the possibility of permitting CfDs in the Capacity Market for DR

It is a hot topic in GB's power system that aims aggregators or BSPs being able to sign CfDs to reduce risk of participation in the CM. This would send strong signals about revenues to smaller customers than could not see real benefits about participating in the market.

Reevaluate the remuneration given in programs such as STOR

It creates big gaps and inequalities between industries that agree on two-window availability and smaller customers that go for the one-window options. It is logical to think that large industries give a greater service by means that these two windows but DRPs must, at least in the former years, internalize the needs and particularities of smaller demand-side customers. Therefore STOR might divide by two the revenues given to two-window users.

Baseline methodology does not apply to all customers

Needs an effort on implementing IT systems with communication to end-customers to make a more efficient use of energy. Some kind of subsidies shall be considered here.

Market Prices do not reflect flexibility enough

Real-time and day-ahead prices are too similar to be appealing for small customers, as they do not find it worthy to participate in DRPs. The recommendation here is to study the possibility to oblige retailers/aggregators/BSPs to buy explicit certificates according to their peak consumption portfolio.

Penetration of DR is almost negligible (0,3% last year)

Demand-side has more of an uncertainty than traditional supply-side. Moreover the supply-side is still more capable to meet capacity requirements at lower prices that are not encouraging enough for DR. Hence the recommendation from Iberdrola's point of view is to first reserve some of the capacity agreed to be only offered in a separated auction for DR participants. Second, to shift the auction from the actual 4-years ahead to 1 to 2 years in advance to diminish uncertainty on the capacity offered to be curtailed. Third, to do extra-quarterly auctions the very same year of delivery to tune the quantity finally available appropriately. Fourth, change pay-as-cleared auctions to pay-as-bid auctions to encourage participation of DR until it becomes more competitive. This is also a way to better reflect flexibility in market prices.

New York State

Permit future DRP offers of third-party entities

Only two actors play this game so this can distort competition.

Small loads are still to be fully implemented in the DSASP

Although New York is very advanced in comparison with other countries or States within the US there is still margin to improve. One of the things to do in the future would be to gradually allow small commercial and residential aggregation of loads to participate more actively in the DSASP. The technology is already in place and in some cases the NYSERDA is able to give subsidies or aids for the installation of such devices, but a greater effort is desirable.

Lack of participation in DADRP and DSASP

This issue arises in part due to the previously commented high loads required to participate in the DSASP program. More flexible clauses need to be considered also in terms of remuneration and transmission of flexibility to market prices. Launch measures to give robustness to the DSASP in order to let residential and commercial small and medium loads to get part of it as an aggregated way. The main hurdle is the 6 seconds response requirement.

Educational Campaigns to achieve higher rate of DRP users

They are a must to increase the number of participants. Once prices, penalties and other features are properly set, the rest is about make customers aware of the potentiality of DRPs.

Propose new rules to protect distributed energy resources

Maybe a proposal similar to GB with variable charges regarding network use so that there are more incentives to install DG. It would also help to send clear signals about how and when DG can curtail production to solve imbalances.

Data integration

The main problem in the NY area is the low rate of demand-side participants. Perhaps if larger investment or subsidies on remotely controlled devices and IT may encourage smaller customers to participate in the programs. We are talking about intelligent monitoring devices.

California

Avoid DRPs that do not bring benefits of constant load modification

DRPs must be cost-effective and provide a responsive effect to the supply side.

Oblige CPUC and CAISO to report to the California State Legislature on the implementation of the Electric Rules 24 and 32

These rules are a breakeven point from the former regulation on DR. Therefore monitoring activities must be carried out to ensure their correct implementation.

Oblige some DRPs to demonstrate their capability to adjust power upwards and downwards in order to better integrate RES-E

As the big share of RES-E penetration in California is the main problem for balancing the grid, DRPs must help to manage them.

Update CPUC's goal of meeting 5% of the system's annual peak energy demand using DRPs by year 2007

To set new goals, ex-ante studies should define what the programs ought accomplish when modifying loads or providing demand reductions as any other traditional resource in California. Bottom-up approach.

Standardization of technological devices

Utilities might provide data to settle transactions favored by smart meters rather than from specialized meters used for today's DRPs.

Permit absorption of excess production from RES-E

This might bring DR the possibility not only of reducing/shifting load but also increasing their consumption as a network tool.

CAISO needs to create application-programming interfaces (APIs)

To allow utilities to integrate their IT platforms into CAISO's platforms.

Make a decision on whether to go for market-based DRPs or to command and control mechanisms

The work done has a mix of both options so signals sent are blurry thus preventing new investment.

Start the DRAM program

Aiming to make demand response to participate in a market to meet the adequacy requirements of the grid in the forthcoming years as done in NY, PJM, UK or next year in France. It would permit **flexible capacity** mainly to deal with the **"duck curve"** issue very common in California and which consists of steep ramps in energy demand when solar PV systems are dumping energy into the grid.

General Assessment

Along this document it has been possible to see a wide variety of approaches for dealing with the Demand Response concept, from very passive countries where few options are offered to regions where the offer is huge and provided by a reasonably high number of entities. The key issue is to understand that the technical starting point and operational particularities of each power sector will determine to what extent customers will perform an active function participating either in the traditional wholesale electricity markets and ancillary services or not.

In this context we have identified **supply-side approaches**, where aggregation is more focused on linking renewable resources and to manage distributed generation as it is frequent in Europe and **demand-side approaches**, most used in the US due to the energy consumption intensity of their users. Also, countries as Spain where networks are oversized and there is a clear gap of over capacity installed, need of a political reading of this topic instead of a technical one. The operational benefits that DR would bring are clear, but collateral damages might be considered when considering measures to facilitate the access of DR. Another question is how to charge for the reinforcements needed in the MV grids.

On the other hand we have seen how countries like France and Great Britain are enjoying a more keen growth process of DR programs. Again, this is just a matter on how the context and the starting point of the system are. France, based mainly on nuclear production and in-home electrical storage heating systems, needs flexible systems that relieve the grid when imbalances occur and help to lower prices by substituting nuclear power plants, providing ancillary services. There have been several successful experiences as the 'Tempo Tariff' and the new capacity market to be launched by 2016 are projected to boost DR in the mid-term. Great Britain presents, contrarily to Spain, a lack of capacity and the decommissioning of old coal plants that were the support of the power sector for many years. This issue added to the incipient nuclear capacity, showed us the necessity of GB to facilitate DR options that help the system by reducing network needs and providing flexibility.

Any electric power system is highly capital-intensive and generally not so flexible. This means that regulation moves only when the power sector needs it. DR brings a varied list of benefits to customers and the system but these welfares have an economic cost. As a consequence these costs will only be permitted, and covered by sound regulation when the operational and technological situation of the power system calls for it.

In the American continent the situation and the way to cope with DR varies a lot with respect to Europe. This study identified the great development of DR options in both California and New York. Additionally, aggregators enjoy a larger range of rights but also responsibilities, and the number of these actors has increased drastically in the last decade. The State of New York presents the problem that requirements, generally for participating in the ancillary services options, require of big load reductions that few customers or aggregators are capable to guarantee. Moreover, the large number of aggregators are not able to guarantee big load reductions in the short-term as DR subscribers are widely spread throughout the 26 licensed aggregators that compete for around 2000 MW of flexible DR capacity. This ends up being due on a lack of participation, which is the main point policymakers and aggregators are trying to solve today.

Something similar happens in California, where capacity is distributed within many aggregators and the number of participants barely reaches the 5% of the eligible peaking capacity. The context in which DR was developed in California was the high consumption patterns, especially during the summer –which has lead to the creation of remote-controlled air conditioning programs-, and to the large penetration of DG, that calls for smart solutions to relief the system of imbalances.

One of the main barriers presented in the US that did not arise in Europe is the alarm of citizens regarding data privacy. Some utilities as Iberdrola, have experienced a lot of problems regarding the installation of SM in States such as Maine or Connecticut, where lots of consumers rejected to have a SM in their home. There are also some campaigns that aim to refuse the installation of these devices since the data they provide is understood to be very sensible.

Another key point to identify is the way in which California and New York have treated ancillary services for the demand-side. For instance frequency restoration programs are not only focused in large industries as it is in Europe but also in residential and commercial in and aggregated way. This can be a mirror for the future development of DRPs in Europe.

Regarding the aggregator figure, which is very controversial, the conclusion is that this figure must respond to the needs and responsibilities that every singular system needs and its role should not be mandated from central institutions. The experiences studied have gone from illegality in the case of Spain to figures with total freedom and capability to manage customers as in GB or New York.

However, the very same experiences have helped us to conclude that the allocation of risks is crucial when defining regulation. The figure that bears more risks and responsibilities to regulatory changes should be clearly defined. Generally (France, NY, GB, California), the most risky position is the one of the aggregator. This is the main reason why aggregators are rarely big electric utilities, indeed they are small start-ups that want to benefit from the low margins DRPs offer and that also seek Governmental subsidies (New York and California).

Concerning financing and penalties, a huge effort was made in this document to understand which payments are correct to send appealing signals and at the same time do not frighten clients with unaffordable penalties for non-compliance. The conclusion is that one more time this depends on the technical needs of each system and the load curve of each case. Yet, cost-effective and opportunity cost methodologies shall theoretically be followed in order to design more efficient programs.

To sum up, all the aforementioned factors demonstrate that DR is still an immature market as very different approaches are taken worldwide and inconsistencies are identified regarding the political and regulatory decisions made in this context. Thus, this topic will continue being discussed in the forthcoming years as the need to meet higher electricity demand grows. Nevertheless, we all, researchers, policymakers, utilities, consumers and other actors need to keep in mind that although DR shorts on the decision on whether to curtail or not such load, all directives have to be focused on giving the end-customers the right to curtail it or not. If so, it will really mean that demand-side participants are empowered.

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