SEDC
Smart Energy Demand Coalition

Mapping Demand Response in Europe Today 2015

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Smart Energy Demand Coalition (SEDC)

The SEDC is an industry group, which supports the development, deployment and utilisation of smart energy demand in order to further the development of the Smart Grid.

The SEDC vision is to promote the active participation by the demand side in European electricity markets – ensure consumer benefits, increase security of supply and reduce carbon emissions.

The SEDC focus is to promote Demand Side programmes such as, demand response and time-varying pricing, energy efficiency, energy usage feedback and information, smart home, in-home and in-building automation, electric vehicle charging management, and other programmes related to making demand a smart, interactive part of the energy value chain.

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SEDC Members

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Foreword

Dear Reader,

The electricity industry is undergoing a dramatic transformation as Europe moves toward a greener, healthier future. The growth in renewable energy has been spectacular, but another topic is emerging as a key driver: the empowered energy consumer.

We founded the Smart Energy Demand Coalition five years ago in a Viennese Kaffeehaus with the explicit vision of "promoting the active participation by the demand side in European electricity markets – ensure consumer benefits, increase security of supply, and reduce carbon emissions." Our focus is to promote demand side programs such as peak clipping and shifting; energy usage feedback; smart home, in-home and in-building automation; electric vehicle charging management; and other programs related to making demand a smart, interactive part of the energy value chain.

Today, the SEDC is proud to be the leading voice for demand response Europe, providing research and education regarding policies, consumer benefits, and enabling technologies. In this spirit, we announce the publication of our latest market review, "*Mapping Demand Response in Europe Today (2015)*."

We trust this will be a valuable tool for policymakers, planners, and practitioners as they grapple with the challenges and opportunities of making the European Union's future energy vision a reality.

Brussels, this 30th day of September 2015.

Chris S. King
Chair
Smart Energy Demand Coalition

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Executive Summary

There is growing consensus, among policy makers and market participants alike, that demand-side flexibility, empowered through Demand Response, is a critical resource for achieving a low carbon, efficient electricity system at a reasonable cost. Today, this understanding is reflected within the European Network Codes, the Energy Efficiency Directive and the European Commission's Energy Union Communication. Within these, Demand Response is named as an important enabler of security of supply, renewables integration, improved market competition and consumer empowerment. It is now an integrated part of Europe's efforts to lower energy costs, support clean energy resources, and combat climate change. In other words, it is understood that Demand Response is an important facilitator of these public aims.

To fulfil Europe's energy goals and political promises, it will not be sufficient to engage one group of consumers, in one programme type, for one market. The **full range** of demand-side resources available (at competitive prices) must be engaged, and the full range of consumers must have the ability to benefit from their flexibility. This will require both Explicit and Implicit Demand Response.

Demand Response empowers consumers (Residential, Commercial or Industrial) by providing control signals and/or financial incentives to adjust their use of demand side resources at strategic times. These demand-side resources may include their consumption, use of distributed generation and/or storage capabilities.

In **Explicit Demand Response schemes** (sometimes called "incentive-based") the **aggregated** demand side resources are **traded** in the wholesale, balancing, and capacity markets. Consumers receive **direct payments** to change their consumption (or generation) patterns upon request, triggered by, for example, activation of balancing energy, differences in electricity prices or a constraint on the network. Consumers can earn from their consumption flexibility individually or by contracting with an aggregator: either a third party aggregator or the customer's supplier. **Implicit Demand Response** (also sometimes called "price-based") refers to consumers choosing to be exposed to *time-varying electricity prices or time-varying network grid tariffs* that reflect the value and cost of electricity and/or transportation in different time periods. They respond to wholesale market price variations or in some cases dynamic grid fees. Introducing the right to flexible prices for consumers (provided by the electricity supplier) does not require the role of the aggregator.

It is important to note that neither form of Demand Response is a replacement for the other. An Explicit Demand Response programme allows a customer to participate in a balancing market as outlined today in the Network Codes. It will also allow for regional demand-side services for Distribution System Operators (DSOs). On the other hand, Implicit Demand Response can be accessed by a wider range of consumers through supplier-enabled dynamic pricing programmes.

The role of aggregation and the need for regulatory clarity: Explicit Demand Response requires the coordinated participation of the full energy value chain. The players involved include the Transmission System Operator (TSO) in balancing markets, the DSO, the supplier, the Balance Responsible Party (BRP) and the aggregation service provider. Most consumers do not have the means to trade directly into the energy markets. In order to engage, consumers therefore require a clearly defined offer, which is both simple to use and contains clear benefits. And they require a party with expertise in **selling and providing this offer** through aggregation. Aggregation service providers (who may or may not be electricity suppliers) are therefore central players in creating vibrant demand-side participation and Explicit Demand Response.

The independent aggregator represents a new role within European electricity markets and defining the role of the aggregator is not an end in itself; rather, it is important due to its positive outcomes**.** An aggregator's success is entirely dependent upon the successful participation of the consumer in Demand Response programmes. The introduction of this role into a market creates critical momentum around the growth of Demand Response, attracts private investment and spurs competition between service providers[1].

To enable the participation of independent aggregation service providers in a safe manner, the relationship between the supplier, Balancing Responsible Party (BRP) and the aggregator **must** be defined. Standardised processes for information exchange, transfer of energy, and financial settlement between these parties are a critical requirement in order to facilitate the smooth functioning of the markets and ensure consumer protection. These should protect consumers' right to choose providers freely, while at the same time ensuring that market functions remain stable, in particular the one of the BRP.

Current Status of Explicit Demand Response

With heightened political expectations, both the costs of failure and the rewards of success increase proportionally. To date, policy makers have **assumed** that consumers will be empowered – and so be able to lower the cost of decarbonisation. Yet this is far from certain. While several Member States have made good progress in the past two years toward realising these assumptions, most still suffer from a critical gap between political plans for consumers and the regulations in place. Regulations, which should support efficient and beneficial consumer engagement, in many cases block consumers from the markets, or worse, open them up to abuse.[2] This is a troubling recent development and should be reviewed by policy makers. Consumers looking to provide demand-side flexibility should be encouraged and protected by regulation, and not be forced to choose between participation and their basic rights, such as data privacy.

The aim of this report is to provide an overview of current regulation in 16 Member States for the implementation of Explicit Demand Response. We focus on Explicit Demand Response because it requires no public investment in technology roll-out, and the business case is already positive[3] . Hence it is 'only' the regulatory framework at EU and national level, which currently decides whether or not Explicit Demand Response services are available to consumers. The report also looks to support the implementation of the Energy Efficiency Directive Art 15.8 (on Demand Response)

[1] For example, in some markets in the USA today, over 80% of demand side volumes are provided through independent aggregators, even though suppliers are able to offer the same services. Similar patterns occur wherever independent aggregation is allowed, including Ireland, Western Australia, Texas and New York.

[2] Consumers lose rights where regulators have yet to create defined standardised processes between aggregators and BRPs. This can leave them open to a range of questionable practices and is not an acceptable outcome of regulatory oversight. Examples can be found in all the countries which have 'open' balancing markets but have not yet clarified the roles and responsibilities of the aggregator. The results include loss of data privacy and other forms of pressure to discourage participation in the Demand Response market.

[3] Though Explicit Demand Response may indeed require investment in updated TSO & DSO processes.

and inform the completion of the Network Codes. (A report covering Implicit Demand Response is due Qu. 2, 2016.)

The information on Member States was gathered through desk research, and expert interviews, with TSOs, DSOs, suppliers, aggregators, regulators and technology providers. National market participants (who work with Demand Response) then reviewed the national reports. Therefore, the findings reflect the experience of the players on the ground. The Member State analysis graded markets according to the four main criteria: 1) Enabling consumer participation and aggregation 2) Appropriate programme requirements 3) Fair and standardised measurement and verification requirements, and 4) Equitable payment and risk structures. Figure 1 provides the final outcome when the results were tabulated and quantified into an overall score.

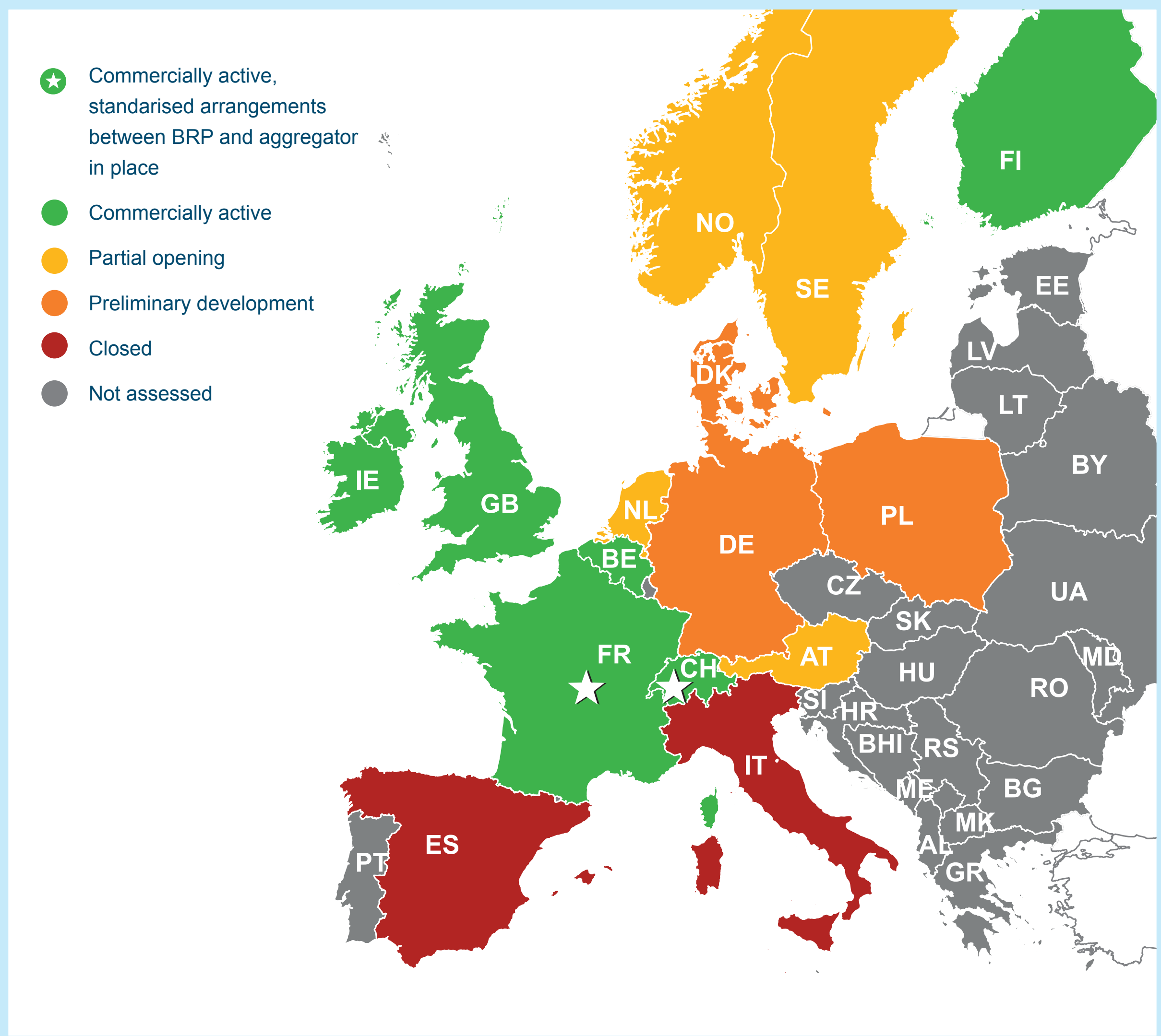

Figure 1: Map of explicit demand response development in Europe Today (SEDC, 2015).

Significant progress at the European level: In 2014-15 the most significant development was perhaps within the European Network Codes. The inclusion of Demand Response in the Network Codes represents a critical, positive step toward widespread consumer engagement in Europe. For the first time, there is a high-level structure enabling the participation of demand-side resources across markets and Member States. This success was achieved through productive stakeholder engagement between demand-side representatives, ENTSO-E, ACER and the European Commission.

That said, work remains: the Codes must be completed in a manner that ensures **a consistent level of consumer rights** across Member States for them to succeed in fostering market growth. This will require a clear and consistent definition and implementation of responsibilities for all players and in particular the BRP and Aggregator. This is yet to be assured and will require the engagement of the European Commission.

The Member States findings indicate **measurable progress** between 2014 and 2015 in response to the Energy Efficiency Directive requirements and the active engagement of National Regulatory Authorities (NRA) and TSOs with stakeholders. However the most significant changes made between 2014 and the first half of 2015 have been ones of solidification rather than significant shifts in position. While Member States which took a decision to enable Explicit Demand Response in 2013-14 have made significant progress, other Member States are still undergoing regulatory reviews or have decided against making any significant changes at this time.

Belgium, Finland, France, Ireland and Switzerland have reached a level where Demand Response is a commercially viable product offering and are therefore coloured green. Great Britain remains green due to its highly competitive energy markets, and open balancing markets, but the future of Demand Response in the country has become more difficult due to the launching of the GB Capacity Market. The market, thus far, is providing £1 billion income stream annually mainly to nuclear and fossil fuel generation resources, but does not create a level playing field for demand-side resources to participate. Finland and Belgium are green due to their positive programme and payment structures, which enable consumer engagement, though neither country has integrated independent aggregators fully into their systems as yet. France and Switzerland have restructured their programme requirements and defined roles and responsibilities of market participants specifically to allow for independent aggregation. Belgium is carrying out a similar review.

Sweden, the Netherlands, Austria and Norway remain 'yellow'.[4] In other words, while Demand Response companies are being established, significant regulatory barriers remain an issue and hinder market growth. This is usually due to programme participation requirements, which are not yet adjusted for both generation and demand-side resources. For example in Austria a consumer may be required to install a secured and dedicated telephone line to participate in the balancing market. In Norway, TSO signals are still delivered over the telephone, and therefore the minimum bid-size remains high. Rules such as these block the participation of all but the very largest industrial consumers. A lack of clarity around roles and responsibilities may also block new entrants.

The remainder of European Member States are orange or red, meaning that aggregated Demand Response is either illegal or its development is seriously hindered for all market participants -large industrial sites, suppliers or independent aggregators- due to regulatory barriers. Denmark, Germany and Italy are conducting regulatory reviews and this status may change in 2016. However,

[4] It should be noted that the Nordics are making significant progress in Implicit Demand Response through dynamic pricing. Smart Meter rollouts are now close to completion throughout the region and it is a mandated requirement that dynamic hourly pricing should be made available to all consumers.

Poland and Spain do not seem to be taking the required steps at this stage; this may be caused by limited regulatory resources or particularly intractable barriers.

Overall main regulatory barriers found repeatedly across Member States include:

1. **Demand Response may not be accepted as a resource:** Many Member States have wholesale, balancing, or capacity markets where aggregated demand is not accepted as a resource (in direct contradiction to the Energy Efficiency Directive, Article 15.8).

2. **Inadequate and/or non-standardised baselines:** It is important that consumers' demand-side flexibility is accurately measured. Many Member States lack standardised measurement and baseline methodologies, or have methodologies, which are designed for generators and therefore do not accurately measure consumption changes. This may entirely block a market, as consumers will not receive payment for the services they deliver.

3. **Technology biased programme requirements:** Consumers may be blocked by historical programme participation requirements, which were designed for the convenience of the national generation fleet only, and have not yet been updated to include the capabilities of demand side resources.

4. **Aggregation services are not fully enabled:** Prequalification, registration and measurement may be still be conducted at the individual consumer level rather than on the pooled load collected by the aggregator, blocking participation by placing heavy administrative and legal burdens on the individual consumer.

5. **Lack of standardised processes between the BRP and Aggregator:** As previously stated, without these processes in place, consumers cannot freely choose their service provider, and market competition around consumer services is severely hampered. It is important that standardised processes protect the customer-aggregator relationship, provide a direct path to market and include a standardised process for bidirectional payment of sourcing costs between the BRP and aggregator.

The EU Demand Response market is still in the early development phase and fragmentation is a result. At the national level, Member States have widely varying regulations, while a single Member State will contain between 4 to 9 separate electricity markets (forward, capacity, day-ahead, intraday, and a set of balancing markets) and each of these markets will have their own participation rules. Worse, in Member States with more than one TSO, each TSO may have different participation rules. Over and above this, even within this already severely fragmented market (28 countries, 4-9 electricity markets per country, individual rules per TSO), it is often impossible or illegal to aggregate customers across balancing zones

There is a critical need for standardised regulation at the European level, including clarified roles and responsibilities. The European Network Codes and the up-coming Market Design Initiative could unify and standardise the regulation across national markets. The Network Codes for example, do not yet provide detailed guidance concerning appropriate programme requirements, baseline methodologies or standardised national processes between market participants. Further guidance is required by European institutions, in particular the European Commission.

Taking into account the potential benefits of Demand Response and the regulatory barriers in place, **clearly defined action-plans**[5] will be required at a European and Member State level to ensure real progress. These should include logical step-by-step **strategies** for market development of consumer demand-side services, measured and verified against well-defined key performance indicators. Only a planned and coordinated effort can help to overcome the systematic historical barriers to Demand Response.

The European Commission's leadership in this process will be essential. The need for consumer empowerment and Demand Response is widely supported. Changing market processes will take time, work and a long-term commitment toward positive development.

[5] Adaptable according to the national contexts. These adaptations need probably cost-benefit analysis in each country member to determine pertinent targets for Demand Response development.

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AD	Active Demand
AEEG	Autorità per l'Energia Elettrica il Gas
AMR	Automatic Meter Reading
APG	Austrian Power Grid
APX	Power Spot Exchange
Belpex	Belgian Power Exchange
BMWi	Bundesministerium für Wirtschaft und Energie
BRP	Balance Responsible Party
BSP	Balancing Service Provider
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CAPEX	Capital Expenditure
CER	Commission for Energy Regulation
CHP	Combined Heat and Power
CIM	Continuous Intraday Market
CM	Capacity Market
DAM	Day Ahead Market
DECC	Department of Energy & Climate Change
DK1	Electricity Grid Price Area for West Denmark
DK2	Electricity Grid Price Area for East Denmark
DR	Demand Response
DSBR	Demand-Side Balancing Reserve
DSO	Distribution System Operator
DSU	Demand Side Unit
EDF	Électricité de France S.A.
EDRP	Emergency Demand Response Program

EED	Energy Efficiency Directive
EEX	European Energy Exchange
ELES	Elektro-Slovenija
ENEL	Ente nazionale per l'energia elettrica
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
ERCOT	Electric Reliability Council of Texas
ERDF	Électricité Réseau Distribution France
FCDM	Frequency Control by Demand Management
FCR	Frequency Containment Reserve
FCR-D	Frequency Controlled Disturbance Reserve
FCR-N	Frequency Containment Reserve - Normal
FERC	Federal Energy Regulatory Commission
FRFS	Fast Reserve Firm Service
FRR	Frequency Restoration Reserve
FRR-A/FRRa	Frequency Restoration Reserve - Automatic
FRR-M/FRRm	Frequency Restoration Reserve - Manual
GW	Gigawatt
GWh	Gigawatt hour
HV Grid	High Voltage Grid
I-SEM	Integrated Single Electricity Market
ICE	Intercontinental Exchange, Inc.
ICH	Interruptible Contract Programme
ICT	Information and Communication Technologies
IGCC	International Control Cooperation
INC	Imbalance Netting Cooperation
ISO-NE	Independent System Operator New England
kW	Kilowatt
kWh	Kilowatt hour
M&V	Measurement and Verification

mHz	MiliHertz
MISO	Midcontinent Independent System Operator, Inc.
MR	Minute Reserve
MW	Megawatt
MWh	Megawatt hour
NEBEF	Notification d'Échange de Blocs d'effacement
NRA	National Regulatory Authority
NYISO	New York Independent System Operator
Ofgem	Office of Gas and Electricity Markets
OMIE	OMI-Polo Español S.A
OPEX	Operating Expense
OTC	Over the Counter
PAB	Pay-as-Bid
PAC	Pay-as-Cleared
PCR	Primary Control Reserve
PJM	Pennsylvania, Jersey, Maryland Market
PQ	Pre-qualification
PSE	Polskie Sieci Elektroenergetyczne
Res	Renewable Energy Sources
RPM	Regulating Power Market
RR	Replacement Reserve
RTE	Réseau de Transport d'Électricité
SBR	Supplemental Balancing Reserve
SCR	Secondary Control Reserve
SDR	Strategic Demand Reserve
SEM	Single Electricity Market
SGEM	Smart Grids and Energy Markets
SGR	Strategic Generation Reserve
SME	Small and Medium Enterprises
SR	Strategic Reserve

STOR	Short Term Operating Reserve
STOR TR	STOR Tender Round
TA	Transitional Arrangements
TOR	Technical and Organisational Rules
ToU	Time-of-Use
TSO	Transmission System Operator
TW	Terawatt
TWh	Terawatt hour
UMIG	Utility Market Implementation Guide
USEF	Universal Smart Energy Framework
VOLL	Value of Lost Load
VPP	Virtual Power Plant

Introduction

Background: Why is Demand Response important?

Electric power systems have three important characteristics:

- Electricity cannot yet be stored economically, so the supply of and demand for electricity must be maintained in balance in real time.
- Grid conditions can change significantly from day-to-day, hour-to-hour, and even within seconds. Demand levels also can change quite rapidly and unexpectedly causing mismatches in supply and demand, which can threaten the integrity of the grid over very large areas within seconds.
- The electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes.

That said, today, most European electricity consumers still pay tariffs that are based on average electricity costs and bear little relation to the stress on the electricity grids and the true generation costs of electricity as they vary over time.

Demand Response is a tariff or programme established to incentivise changes in electric consumption patterns by end-use consumers in response to changes in the price of electricity over time, or to incentivise payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardised.

Demand Response is able to increase the system's adequacy and to substantially reduce the need for investment in peaking generation by shifting consumption away from times of extremely high demand. It can act as a cost effective balancing resource for variable renewable generation. Adding stability to the system, it lowers the need for coal and gas fired spinning reserves – must run power plants, burning fuel continuously, in order to be ready to supply power at short notice. It can decrease the need for local network investments, as it can shift consumption away from peak hours in regions with tight network capacity.

Apart from the indirect benefits that Demand Response delivers to society by lowering the costs and optimising the efficiency of the electric systems and markets, it also provides **direct** benefits to consumers by paying them directly for the value of their demand-side flexibility. In the USA this amounted to over €2.2 billion[6] in 2014. Finally, it encourages market competition, by allowing the participation of third party service providers (aggregators) and rewarding service-oriented suppliers.

Within the 2030 EU policy framework, Demand Response is regarded as key tool to achieve the targets of at least 27% for renewable energy and energy savings by 2030. It is now clear to policymakers that Europe will not be able to achieve these goals in a secure and cost-efficient manner unless our energy system becomes more flexible. Demand Response and consumer empowerment are understood as integral parts of the Energy Union's action plan, as they increase security of supply, by reducing dependence on foreign

[6] Joule Assets (2015)

imports and supporting renewable integration[7]. In the wider EU policy context, Demand Response is not only promoted because it addresses the **energy** trilemma, but also because it helps to reach a competitive, secure and sustainable **economy**. It does so by forming a natural partnership with renewable resources and energy efficiency. Each improves the performance and financial returns of the other, spurring increased investment and job creation.

Enabling both Explicit & Implicit Demand Response

Demand Response delivers these benefits by providing consumers – residential, commercial[8] or industrial – with control signals and/or financial incentives to adjust their consumption at strategic times. Demand Response programmes can be categorised into two groups:

In **Explicit Demand Response schemes** (sometimes called "incentive-based") the control of aggregated changes in load are traded in electricity markets, providing comparable services to supply-side resources, and receiving the same prices for those services. Usually this takes place within the balancing, capacity or wholesale energy markets. Consumers receive direct payments to change their consumption upon request (i.e., consuming more or less), which is typically triggered by activation of balancing services, differences in electricity prices or a constraint on the network.

Consumers can earn from their flexibility in electricity consumption individually or by contracting with an aggregator. The latter can either be a third-party aggregator or the customer's supplier.

Implicit Demand Response (sometimes called "price-based") refers to consumers choosing to be exposed to *time-varying electricity prices* or *time-varying network tariffs* (or both) that partly reflect the value or cost of electricity and/or transportation in different time periods and react to those price differences depending on their own possibilities and constraints (no commitment).

It is important to note that neither form of Demand Response is a replacement for the other. Many customers participate in Explicit Demand Response through an aggregator, and at the same time, they also participate in an Implicit Demand Response programme, through more or less dynamic tariffs. The requirements and benefits of each are different and build on each other. The two are activated at different times and serve different purposes within the markets. They are also valued differently. While consumers will typically receive a lower bill by participating in a dynamic pricing programme, they will receive a direct payment for participating in an Explicit Demand Response programme.

Perhaps most importantly, Explicit Demand Response provides a valuable and reliable operational tool for system operators to adjust load to resolve operational issues. Implicit Demand Response, on the other hand, allows consumers to benefit from price fluctuations in the wholesale energy markets to the extent they are willing and able. Therefore, a dynamic pricing programme does not allow a customer to participate in balancing markets, or in most existing capacity markets, which are currently the greatest sources of revenue for con-

[7] Brussels, 25.2.2015 COM (2015). Energy Union Package. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank. A framework strategy for a resilient Energy Union with a forward-looking climate change policy.

[8] The term Commercial is used here to mean all buildings and businesses which are not directly industrial or residential. In other words, municipal buildings, SMEs, businesses such as hotels, office spaces, etc.

sumers. It will also not allow for regional demand-side services for TSOs and DSOs, and it does not provide the system as a whole with a dispatchable resource. On the other hand, Explicit Demand Response does not have the same market reach as a supplier-enabled dynamic pricing programme. **Both forms** are therefore required to allow consumers to **fully participate in the markets** and benefit from their flexibility.

Benefits of aggregation

An aggregator is a service provider who operates – directly or indirectly – a set of demand facilities in order to sell pools of electric loads as single units in electricity markets. The aggregator – a service provider who may or may not also be a supplier of electricity – represents a new role within European electricity markets. Most consumers do not have the means to trade directly into the energy markets because, for example, they are too small to manage the complexity. They require the services of an aggregator to help them participate. Aggregators pool many different loads of varying characteristics and provide backup for individual loads as part of the pooling activity, increasing the overall reliability and reducing risk for individual participants. Aggregation service providers are central players in creating vibrant demand-side participation and Demand Response. **Aggregators** "aggregate" consumers' flexibility, to "build" reliable Demand Response services: they negotiate agreements with industrial, commercial and residential electricity consumers to aggregate their capability to reduce energy and/or shift loads on short notice. They create one "pool" of aggregated controllable load, made up of many smaller consumer loads, and sell this as a **single resource**. These loads can include fans, electric heating and cooling, water boilers, grinders, smelters, water pumps, freezers, etc.

It is important to recognise that the activity of aggregating consumers' loads requires a number of very specific competencies unique to this role. For example, the aggregator needs significant industry knowledge and experience to identify the flexibilities in various industries, technical assets and processes, and the limitations of those flexibilities, in order to match these to the requirements in a specific market. Consumers often do not know about their own potential for flexibility, so they need expert support. In addition, aggregators have the technical capability to physically connect the customers and integrate their load into their aggregated pool. These activities require a sophisticated communication infrastructure (hardware and software) and a central IT system capable of dealing with a wide variety of loads with different properties.

Aggregation can achieve performance levels that fulfil market requirements for reliability and can be comparable to or better than the performance of generation. The aggregation of diverse customers means that the system operator can utilise the aggregated demand-side capacity as a single, reliable resource. One of the key benefits of aggregation is the diversity of the aggregated portfolio (i.e., many small loads building one large resource), which ensures that the committed capacity will be delivered by the aggregator even when some individual consumers may not be able to perform[9].

[9] The aggregator will also never bid his full resource into a market – for example if he has 100 MW of load available, he may only offer 70-80 MW into the market – ensuring that the aggregator can fulfil his reliability requirement with high reliability.

The performance levels of Demand Response have been proven in existing markets in North America and Australasia, as well as in Austria, Belgium, Finland, France, Ireland and the UK. An example of the reliability of Demand Response can be seen in the table below. The table summarises the performance of Demand Response in PJM's summer product, during the period 2014-2015.

Zone	Committed ICAP (MW)	Reduction (MW)	Over/under performance (MW)	Performance (%)	Re-test (%)
AECO	43	67	24	155%	9%
AEP	1094	1674	580	153%	0%
APS	451	566	115	125%	0%
ATSI	640	868	228	136%	0%
BGE	667	1369	702	205%	0%
COMED	901	976	75	108%	61%
DAY	126	179	53	142%	56%
DEOK	244	287	44	118%	46%
DOM	731	938	207	128%	0%
DPL	122	149	27	122%	2%
DUQ	76	105	28	137%	0%
EKPC	123	132	9	108%	0%
JCPL	120	159	39	132%	39%
METED	188	239	50	127%	0%
PECO	341	408	67	120%	7%
PENELEC	241	270	29	112%	0%
PEPCO	184	253	69	138%	6%
PPL	503	628	124	125%	4%
PSEG	361	400	39	111%	0%
RECO	2	3	1	125%	0%
Total	7158	9668	2510	135%	12%

Table 1: PJM, Load Management Performance Report – 2014/2015. Load Management commitments, compliance, and test performance (ICAP) for Limited Summer product (where over-delivery is allowed)

Clarifying the role of the independent aggregator is important for the healthy growth of market competition around consumer-centric services. For example, the latest PJM Market Activity Report on Demand Response (from August 2015) shows that 82% of Demand Response capacity in PJM comes from independent aggregators[10]. This trend has been increasing over the last few years. The shares are similarly high in other jurisdictions that have mature Demand Response markets, such as Western Australia, New Zealand or other US interconnections (e.g., New England and New York). An aggregator can **only** succeed when their customers succeed and benefit from Demand Response. This is not to say that suppliers cannot provide aggregation services, it is simply an indication of the need for a market participant for whom Demand Response is their **core business**. This spurs competition in Demand Response services for customers.

The following chapter outlines the existing provisions for Demand Response at the EU level and analyses a set of regulatory requirements for truly enabling consumer participation in the electricity markets.

[10] PJM, 2015, Demand-Response Operation Marketactivity report August 2015; PJM calls aggregators Curtailment Service Providers (CSPs).

1

Regulatory Requirements for Enabling Demand Response

1.1 European Regulatory Framework for Demand Response

The European policy makers have demonstrated strong support for Demand Response. This is reflected in several important legislative texts:

The Electricity Directive – 2009/72/EC

The Electricity Directive[11] of the Third Energy Package defines the concept of "energy efficiency/demand-side management", acknowledging the positive impact on environment, on security of supply, on reducing primary energy consumption and peak loads. The Art. 25.7 requires network operators to consider Demand Response and energy efficiency measures when planning system upgrades. Art. 3.2 also states *"In relation to security of supply, energy efficiency/ demand-side management and for the fulfilment of environmental goals and goals for energy from renewable sources, [...] Member States may introduce the implementation of long-term planning, taking into account the possibility of third parties seeking access to the system".* This language was strengthened further within the Energy Efficiency Directive (EED).

The Energy Efficiency Directive (EED) – 2012/27/EU

The Energy Efficiency Directive (2012/27/EU)[12] constitutes a major step towards the development of Demand Response in Europe.

According to its Art. 15.2, Member States were required to undertake an assessment of the energy efficiency potentials of their gas and electricity infrastructure, in particular regarding transmission, distribution, load management and interoperability, […] and identify concrete measures and investments for the introduction of cost-effective energy efficiency improvements in the network infrastructure, by 30 June 2015.

Furthermore, Art. 15. 4 requires Member States to:

- "*Ensure the removal of those incentives in transmission and distribution tariffs that are detrimental to the overall efficiency (including energy efficiency) of the generation, transmission, distribution and supply of electricity or those that might hamper participation of Demand Response, in balancing markets and ancillary services procurement*".
- "*Ensure that network operators are incentivised to improve efficiency in infrastructure design and operation, and, within the framework of Directive 2009/72/EC, that tariffs allow suppliers to improve consumer participation in system efficiency, including Demand Response, depending on national circumstances*".

Of outmost importance is Art. 15.8 of the Directive, which establishes consumer access to the energy markets, either individually or through aggregation. In detail the Article states:

- "*Member States shall ensure that national regulatory authorities encourage demand side resources, such as Demand Response, to participate alongside supply in wholesale and retail markets.*"
- "Subject to technical constraints inherent in managing networks, Member States shall ensure that transmission system operators and distribution system operators, in meeting requirements for balancing and ancillary services, treat demand

[11] Directive 2009/72/EC, concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, 13 July 2009, art. 2 "Definitions".

[12] Directive 2012/27/EU, on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC, 25 October 2012.

response providers, including aggregators, in a non-discriminatory manner, on the basis of their technical capabilities."

- "*Member States shall promote access to and participation of Demand Response in balancing, reserves and other system services markets, inter alia by requiring national regulatory authorities […] in close cooperation with demand service providers and consumers, to define technical modalities for participation in these markets on the basis of the technical requirements of these markets and the capabilities of Demand Response. Such specifications shall include the participation of aggregators.*"

The 5th of June 2014 marked the end of the transposition period of the EED. Member States have submitted their National Energy Efficiency Action Plans outlining how they plan to implement the Directive and the European Commission is now in the process of checking and enforcing compliance of national implementing measures under the EED.

The Network Codes

The codes are a set of rules drafted by European Network of Transmission System Operators for Electricity (ENTSO-E), with guidance from the Agency for the Cooperation of Energy Regulators (ACER), to facilitate the harmonisation, integration and efficiency of the European electricity market. The importance of enabling Demand Response through the codes is already very clear in the ACER's Framework Guidelines on Electricity Balancing: "*These terms and conditions, (...) including the underlying requirements,* ***shall, in particular, be set in order to facilitate the participation of Demand Response,*** *renewable and intermittent energy sources in the balancing markets...*"

The Network Codes will create the foundation for the realisation of the provisions of two aforementioned Directives on Demand Response. Some of the Codes that are expected to be finalised and adopted in the coming months, such as the **Demand Connection Code**, the **Electricity Balancing Code** and the **Emergency & Restoration Code**, will be critical for the development of Demand Response, because they describe the terms and conditions under which Demand-side flexibility providers will be able to participate in the electricity markets.

ACER's recommendation for the Network Code Electricity Balancing includes article 31, which specifically deals with enabling *independent provision of demand-side response.* In this article, the Draft Network Code describes which processes should be standardised, including the adjustment of energy volumes and financial settlement. Creating these standards and making aggregators independent of the consent of the consumer's energy supplier are crucial steps in creating competition to procure explicit Demand Response services from consumers. However, in its current form, this provision is optional for member states. If the European Commission does not make it mandatory, this could result in further fragmentation of the Demand Response landscape in Europe.

State aid Guidelines for Energy and Environment

In April 2014, the European Commission adopted new rules on public support for projects in the field of environmental protection and energy. Among other issues, the new Guidelines clarify under what conditions state aid to secure adequate electricity generation is permitted. This allows Member States to introduce so-called "capacity mechanisms", for example to encourage producers to build new generation capacity or prevent them from shutting down existing plants or to reward consumers to reduce electricity consumption in peak hours. Although the text still refers to "generation adequacy", it requests the primary consideration of "alternatives" to capacity mechanisms, such as Demand Response. The rules state that once set up, the capacity mechanisms must provide adequate incentives to existing and future generation, Demand Response and storage. In detail, this is clarified in the following provisions:

- *(221) [...] Member States should therefore primarily consider alternative ways of achieving generation adequacy which do not have a negative impact on the objective of phasing out environmentally or economically harmful subsidies, such as facilitating demand side management and increasing interconnection capacity.*

- *(227) The measure should be open to and provide adequate incentives to both existing and future generators and to operators using substitutable technologies, such as demand-side response or storage solutions. [...]*

- *(232) The measure should be designed in a way so as to make it possible for any capacity which can effectively contribute to addressing the generation adequacy problem to participate in the measure, in particular, taking into account the following factors:*

- *(a) the participation of generators using different technologies and of operators offering measures with equivalent technical performance, for example demand side management, interconnectors and storage.*

Given that a number of Member States have already introduced or are considering introducing capacity markets, these rules will be vital to create the solid legal basis needed to ensure that, when state aid is permitted for guaranteeing system adequacy, it should be provided in such a way that demand-side resources are not excluded, and so the lowest cost combination of resources can be acquired. However, the real value of these guidelines in creating a level playing field between the different technologies will depend on the Commission's resolve to apply them.

1.2 Regulatory Needs to Enable Demand Response

Based on its previous reports *Demand Response Action Plan* and *Mapping Demand Response in Europe 2014*, the SEDC has developed a set of regulatory requirements to enable Demand Response. The requirements are structured around four main criteria:

- Enable Consumer Participation
- Create Viable Products
- Develop Measurement and Verification Requirements
- Ensure Fair Payment and Penalties

Enable Consumer Participation

The first set of requirements assesses the conditions for healthy competition between the different market actors, traditional and new, all seeking to involve consumers in a range of Demand Response programmes.

There is a striking contrast between the requirements of the EED and the effective means at the disposal of consumers willing to access the day-ahead, intraday, balancing or other markets. Today, few Demand Response service providers exist in Europe, and thus, in most EU Member States, only the very largest industrial consumers, with their own bilateral power purchasing agreements, can participate in Demand Response programmes. This is mostly due to an incomplete regulatory environment in the majority of Member States. To enable consumer participation, a set of regulatory steps should be fulfilled:

Participation of demand-side resources in electricity markets should be authorised.

This very simple condition is far from being fulfilled in the majority of EU Member States. In fact, in the majority of national electricity markets, demand-side resources are not allowed to participate, or they are allowed to participate just in one programme. For example, in Italy and in Spain, loads can only participate in one specific scheme (interruptible contracts), which is rarely triggered. The rest of the balancing and ancillary services can only be accessed by generation.

Aggregated load should be allo wed and encouraged to participate.

As described in the introduction, to make a significant quantity of demand-side side flexibility resources available to the system, TSOs and market operators have to open the markets to aggregated load. Most countries which have opened their product requirements to Demand Response have also enabled aggregated load to participate (e.g. France, Belgium, Switzerland, Great Britain, etc.). On the contrary, other European countries opened some of their markets to load participation, but not to aggregated load, therefore disqualifying all except the largest industrial consumers from accessing these markets (e.g. Slovenia, Poland).

Enabling independent aggregation

Enabling independent aggregation is important for the healthy growth of market competition around consumer-centric services. For example, the latest PJM Market Activity Report on Demand Response (August 2015) shows that **82% of Demand Response capacity in PJM is provided from independent aggregators**[13]. This trend has been increasing over the last few years. The shares are also high in other jurisdictions that have mature Demand Response markets, such as Western Australia, New Zealand or other US interconnections (e.g. New England and New York). An aggregator can only succeed when their customers succeed and benefit from Demand Response. Suppliers are also capable of providing aggregation services and can play an important role in explicit Demand Response programmes. However, the evidence from other markets shows that, for these services to be successful and lead to market growth, it must be possible for consumer flexibility to be unbundled from the sale of electricity.

To enable independent aggregators to enter the market in a safe and scalable manner, it is critical that the role and responsibilities of these new entrants are clarified. In particular, it is important that the relationships between suppliers, BRPs, and independent aggregators are clear, fair, and allow for fair competition.

Main principles and starting point of clarification of roles and responsibilities:

First principle of competitive market design: To promote demand-side flexibility, a market design should guard consumer interests and create a level playing field for all competitors. Consumers that wish to generate revenue from their flexibility should be able to choose freely between all market options and available service providers. They should not be restricted to using a service provider that is tied to or approved of by their supplier.

For this to happen, the aggregation service provider must be able to operate independently from the consumer's BRP/supplier, which is potentially its competitor[14]. Therefore, standardised frameworks and processes should be put in place to enable the smooth functioning of the market and at the same time protect the customer-aggregator relationship. Below is a short overview of the structure of this standardised process between the consumer's BRP and the independent aggregator.

In principle, a standardised framework should:

- create a level playing field on which (small) new market participants can compete with (larger) incumbent companies, encouraging market competition, improved services and freedom of choice for consumers. This includes provisions that allow aggregators to offer Demand Response services to consumers independently of the consumer's BRP/supplier.
- be cost efficient, allow for smooth market functioning, and allocate costs and rewards fairly amongst market parties.
- include processes for correcting the volumes in each affected balancing group, rules for compensation between BRP and aggregator, and provisions for information exchange that safeguard commercially sensitive information.

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[13] PJM, 2015, Demand-Response Operation Market activity report August 2015;

[14] The French competition authority, in its opinion 13-A-19, declares that the prior agreement to be given by a BRP for the participation on a market by an aggregator was not compliant with article 14.6 of the directive "Services" 2006.123/EC (12 December 2006). This article prohibits *"the direct or indirect involvement of competing operators, including within consultative bodies, in the granting of authorisations or in the adoption of other decisions of the competent authorities, with the exception of professional bodies and associations or other organisations acting as the competent authority; this prohibition shall not concern the consultation of organisations, such as chambers of commerce or social partners, on matters other than individual applications for authorisation, or a consultation of the public at large".* It is also important to note that if the consumer's supplier owns generation assets, the consumer's demand side flexibility is also a competitor to the supplier's supply side generation.

Content of the standardised framework: There are four elements to be defined through a standardised framework to allow the market to function reliably while allowing consumers to choose their aggregation service provider. Standardisation sets out "the rules of play":

- ***Volumes:*** Standardised processes for assessment of the traded energy between the BRP and the aggregator[15].
- ***Compensation:*** A price formula to calculate the price for the transferred energy. In the case of demand reduction, the aggregator pays the BRP; in the case of demand enhancement, the BRP pays the aggregator. This price formula should reflect as closely as possible the average sourcing costs of the energy transferred.
- ***Data exchange:*** A clear definition of what data needs to be exchanged between BRP and aggregator to ensure both can fulfil their obligations whilst not having to share commercially sensitive information.
- ***Governance structure:*** An appeals process and an appeals body, in case any issues need to be resolved.

Different adjustment mechanisms to address the above situation have been trialled in a few EU member states and implemented in international markets. **It is important that any settlement procedures are fair, standardised and well defined by the regulator and TSO in order to protect the financial interests of all parties**[16].

Create Viable Products

The second set of criteria against which the SEDC assessed the development of the regulatory environment for Demand Response in the different Member States was whether the participation requirements in the electricity markets enable access by a range of resources, including demand-side resources.

While genuine system constraints and security concerns must be respected, many different product/ programme participation requirements were historically designed around the specifics of generators. Today these narrow criteria are no longer justifiable because they block low-cost demand-side resources, and hence artificially inflate procurement costs. For example, a system's physical need for reserves typically requires the resource to be available for between ½-2 hours. However, the market participation requirements may state that load must be available for 12 hours up to 16 hours. This fits the requirements of coal-fired generation, which can operate for extended periods of time at minimal incremental cost once the start-up costs have been incurred, but it does not reflect the actual system need. This may not have been a problem in the past, but it is now, as it blocks consumer participation, since most consumers are unable to adjust their consumption for 16 consecutive hours. Markets should be designed in a granular manner, in order to enable the full range of resources to enter.

[15] Transfer of energy between the BRP's and the aggregator's balancing groups following a Demand Response dispatch.

[16] For further information on the standardised framework please read the SEDC White Paper: Clarification of the standard processes required between BRPs and independent aggregators, available at the SEDC website.

Product descriptions are historically oriented towards generation standards.

Here is a list of the most frequent hurdles with regards to product design faced by demand-side resources in the different European markets:

- **Over-sized minimum bids:** a consumer or aggregator may need to provide up to 50 MW to participate – rather than the more standard 3-5 MW or less.

- **Extended duration or availability requirement:** some demand-side resources may not be available for extended periods of time (e.g. 12 hours duration for Secondary Reserves in Germany) or would present different availability characteristics than generation (difference between week days/weekend, business hours/night hours, etc.).

- **Too frequent activations/short recovery periods:** this is done when a TSO does not want to have to make multiple calls for resources but prefers to make a single call and then have the resources available. This is convenient for the TSO, but lowers the ability of a range of resources – including demand and renewable resources – from participating.

- **Symmetric bids:** few consumers can increase and decrease consumption equally. A requirement for symmetrical bids acts as a significant market barrier to consumer participation. In Member states where the TSO is willing to enable Demand Response, asymmetrical bids are allowed.

The participation rules of the different products/programmes should allow a range of technologies to participate, taking into account their different characteristics, while ensuring that the system's needs are met. In a competitive market, the TSO and regulator have the responsibility to enable a range of resources to compete on an equal footing – not only selected forms of generation.

Each Member State has individual market structures and therefore there is not a one-size-fits-all set of perfect market products. Figure 2 illustrates a range of choices when designing Demand Response programmes, and how different choices impact on likely levels of participation by the demand side[17].

[17] For more information on Product Elements & Best Practices please see Annex III

Figure 2: Range of choices that determine the level of consumer participation in the product (EnerNOC)

Develop Measurement and Verification Requirements

The third set of criteria of the SEDC Member State analysis reviewed the measurement and verification standards within a market.

Performance measurement, which is typically known as measurement and verification (M&V), is the process of quantifying and validating the provision of the service according to the specifications of a product. The performance measurement process usually occurs at three stages:

- To qualify potential resources against product specifications as an entry gate to participation.
- To verify resource conformance to the product specifications during and after participation.
- To calculate the amount of product delivered by the resource as part of financial settlements.

Critical elements required to measure and verify a Demand Response activation are:

- baseline methodology metering configuration
- product delivery
- communication requirements
- frequency of interval readings
- accuracy standards
- timeliness of measurement data and
- communication protocols

Main characteristics of the performance measurement process:

All resources should be held to the performance specifications established by the product. However, demand-side and generation-side communication requirements will usually need to be designed separately and made appropriate to the characteristics of each. Measurement and verification protocols need to ensure reliable delivery of demand-side services in a manner that will still enable strong resource development.

Measurement and verification process should take place at the aggregated level.

It is important that, in the case of aggregation (by third party aggregators or suppliers), the communication protocols imposed are between the system operator and the aggregator. These protocols should not be mandated down to the individual customers. The latter communications should be at the discretion of the aggregator and his customer(s), so long as the aggregator is able to appropriately aggregate the data from his customers and pass that data to the system operator per specified protocols. This ensures that the system operator secures the data without additional special communications equipment and avoids the system operator the requirement of further transposing the data between communications systems once received.

This distinction is necessary because services provided by aggregated load can involve communications with hundreds of remote customer sites: quite a different situation from centralised generation. Communication requirements that may seem reasonable for a large power station are often prohibitively burdensome when applied to hundreds of individual customers.

Fair and transparent baseline methodologies should be publicly available

The volume of demand variation being sold into the market is assessed against a baseline. Volumes of demand-side flexibility are calculated as the difference between what the consumers normally consume (the baseline) and their actual measured consumption during the dispatch, measured using appropriate metering. The baseline cannot be measured directly, so it must be calculated based on other available measured data, using an agreed, robust methodology. Member States should adopt a small number of standardised baseline calculation formulas, ideally the same across Member State boundaries.

Transparent and reliable methodologies have been put in place in different markets around the world and there is extensive bibliography[18]. However, if there is a lack of transparency concerning the methodology and its requirements, this acts as a strong barrier against the development of Demand Response programmes. It is therefore essential that the methodologies in place are made available to consumers and Demand Response service providers.

Measurement and verification should be **accurate** enough to prevent free riding. Where possible, it should be **standardised**, taking into account that multiple standard baselines must exist to cover different types of Demand Response activations on a range of different consumption sites. This variety of standard baselines is common practice throughout the different balancing markets in which Demand Response currently participates. The existing baselines from these balancing markets should be a starting point to define standard baseline methodologies, although other markets have found that different methodologies are needed for programmes which have longer dispatches or longer notice periods. Depending on the market, these standards could be decided by the appropriate national authority within each Member State or by the TSO.

Dynamic tariffs and baseline methodologies: The baseline is the interpolation of the actual behaviour of the consumer. This includes the customer's behaviour in relation to electricity prices. Existing baseline methodologies have the capability of capturing this behaviour and should do so, where and when appropriate.

Ensure Fair Payment and Penalties

Payments and penalties is the fourth set of criteria reviewed in each Member State.

The market should be transparent

Payment criteria, volumes and values should be transparent and based on open and fair competition. For similar services delivered to the system, meeting the requirements of the market, compensation for Demand Response services should be commensurate with those services delivered by generation.

In many European Member States today, generation resources have access to the markets at an embedded guaranteed cost through a longstanding bilateral agreement with the TSO or supplier. This can result in suppressing the price for new entrants, such as aggregators, providing Demand Response services.

The market structures should reward and maximise flexibility and capacity in a manner that provides investment stability

The market structures should value and pay for flexibility. This will entail availability payments, a guaranteed

[18] Information on Measurement and Verification is technically detailed. For further information and more examples on Baselines, as well as an explanation of the appropriate measurement and verification elements, please see Annex IV

number of activations during the year or some other form of reliable form of payment. These should create investment stability to allow for the new build of resources designed to be available at short notice and for short periods of time. Ideally, market participants should be paid according to the Pay as Cleared (PAC) principle, to allow for the most competitive outcomes.

Penalties for non-compliance should be fair and should not favour one resource over the other.

Penalties are needed to ensure reliability, so both supply-side and demand-side resources should be penalised for non-compliance. That said, penalty calculations for each may need to be differentiated depending on the market. The calculation must be realised on risk for the system, related to the non-delivery product impact (different for each market). It is important that regulators do not use a one-size-fits-all model or they may unintentionally shut out consumer participation.

2

Member States Analysis

2.1 Methodology

Scope

While the 2014 report[19] focussed on the development of explicit or 'incentive-based' Demand Response mainly in the balancing markets, the updated 2015 report covers a wider range of markets (i.e. day-ahead, intra-day, balancing and capacity markets).

Country selection

The paper reviews the regulatory structures of 16 European countries. The 2015 report examines all countries studied in 2014, plus Slovenia. The selection was based on a preliminary research, which identified the European countries where progress Demand Response development was detectable. In detail, the countries researched are:

EU Member States			
Austria	Belgium	Denmark	Finland
France	Germany	Great Britain	Ireland
Italy	Netherlands	Poland	Slovenia
Spain	Sweden		

Non-EU Member States	
Norway	Switzerland

[19] SEDC (2014), Mapping Demand Response In Europe Today

Information gathering

The information was collected through desk research of regulation and market results, and expert interviews with the respective National Regulatory Authorities (NRAs), TSOs, DSOs, suppliers, aggregators, technology providers, consulting firms, research organisations and universities. National market participants (working with Demand Response) then reviewed the national reports. The findings therefore reflect the experience of the players on the ground.

Colour-coding and grading system used for analysis

The countries assessed were given a 'grade' – a colour code and number grade per assessed area. This was done in order to provide a **visual key** and an 'at a glance' analysis of each country's progress in the key areas required for enabling Demand Response. By combining the grades given to these four key areas, a map was created reflecting the status of incentive based Demand Response in Europe.

The 4 key areas on which the assessment of incentive-based Demand Response development was measured are:

- Consumer Access and Aggregation
- Programme Description and Requirements
- Measurement and Verification
- Finance and Penalties

Area 1. Consumer Access and Aggregation

This area encompasses fundamental conditions for the existence of Demand Response. It includes whether, and to what extent, demand is allowed as a resource within the different national electricity markets, and whether aggregation of demand-side resources is permitted and enabled. It also involves the clarification of involved parties' roles and responsibilities, allowing for direct access of consumers to service providers and therefore a clear path to the markets. In particular, it focuses on progress towards fair and standardised arrangements between **BRPs/**suppliers and aggregators. The relationship between third-party aggregators and BRPs has been classified as a market enabler or a barrier, with specific reference to standardised contractual agreements that resolve risks to the BRP/supplier caused by Demand Response activations by a third-party aggregator, namely imbalance and open energy position.

KEY	Consumer Access & Aggregation
5	Aggregated load is accepted in a range of markets, standardised arrangements between involved parties are in place – enabled through an independent third party
3	Aggregated load is accepted only in limited number of markets, lack of standardised arrangements between involved parties
1	Aggregated load is accepted only in one or two programmes, lack of standardised arrangements between involved parties
0	Load is not accepted as a resource in any market

Area 2. Programme Requirements

This area refers to the requirements of the different products/programmes (e.g. minimum bid limit, symmetric bid, maximum number of activations, notification time, duration, etc.), assessing whether these enable demand-side resources to participate.

KEY	Programme Requirements
5	Programme requirements adjusted to enable a range of resources (supply and demand) to participate in multiple markets
3	Minor barriers to demand-side participation in market remain, however participation is still possible
1	Significant barriers remain, creating major competition issues for demand-side resource participation
0	Programme requirements block demand-side participation

Area 3. Measurement and Verification

This area refers to standardised and transparent regulation on how Demand Response events should be measured. In detail, it looks at the definition of baseline methodologies in a harmonised and fair manner. It covers questions such as whether the requirements for measurement are proportionate to small consumer capabilities, taking into account the associated costs. It examines whether the pool of loads can fulfil the measurement requirements as an aggregate, or these take place individually at a per-consumer level.

KEY	Measurement and Verification
5	Requirements are well defined, standardised, proportionate to customer capabilities, and dealt with at the aggregated level
3	Requirements are under development, but do not act as a significant barrier
1	Requirements act as a significant barrier to consumer participation
0	There are no measurement and verification rules for Demand Response participation

Area 4. Finance & Penalties

This area examines whether payments for providing demand-side flexibility are fair, transparent and attractive. Apart from studying whether the financial conditions are healthy, including whether penalties for non-delivery are reasonable or discourage customer participation.

KEY	Finance & Penalties
5	Payment is fair and penalties are reasonable
3	Payment is adequate, but unequal per MW between supply and demand; Penalty structures create risk issues for service providers, but participation is still possible
1	Payment structures seem inadequate, unequal pay per MW between supply and demand, penalty structures create high risk issues
0	Payment structure inadequate and non-transparent; penalty structures act as a critical barrier

Overall Grading

Once this initial analysis was completed, each Member State was given an overall grade according to the general status of independent Demand Response in the overall electricity market. This final grade consists of the total sum of the results in the four aforementioned sections. A star was added to emphasise markets where a standardised arrangements between involved parties has been put in place.

KEY	Status of explicit Demand Response
★ 12 - 20	Commercially active and standardised BRP-aggregator arrangement in place
12 - 20	Commercially active
10 - 11	Partial opening
4 - 9	Preliminary development
0 - 3	Closed

2.2 Member States Reports

Austria

Overview

Austria made progress between 2013 and 2014 in enabling Demand Response within the Balancing Markets. However the overall structure remains complicated (and therefore expensive) to navigate and business development is still slow. In 2014 several amendments in the preconditions for the prequalification were implemented to ease the aggregation of demand resources and open the balancing market to Demand Response in Austria. Especially the possibility of pooling, the reduction of minimum size of a technical unit and the participation of consumers contributes to this.

However, a Demand Response provider has to have a bilateral agreement with the BRP for the BRP's sourcing costs, which creates an obstacle for entering the market. Interruptible contracts for large industrial consumers are not available and although in principal Demand Response could access the EPEX day-ahead market, practically no such activity is currently registered. There are also unjustified historical barriers which remain, such as that each consumer participating in a balancing market may be required to install dedicated telephone line, costing several thousand euros.

1. Consumer access & aggregation

Though several Balancing Markets are open to Demand Response, the BRP – Aggregator relationship does not allow for equal competition between aggregation service providers. This is visibly slowing market development in Austria as aggregators wait, sometimes over a year, for basic contractual arrangement to be completed. Certain customers have given up and disengaged from any effort to enter the market due to these barriers. Therefore the SEDC green grading of 2013-14 has had to be removed from this market.

A. Markets overview

The following table shows the electricity market products or sub-products and underlines where Demand Response and aggregation could participate, with the related market size.

ENTSO-E's terminology	APG's terminology		Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Control	+ / –	67 MW	✔ n/a	✔ *
FRR	Secondary Control	+	200 MW	✔ n/a	✔ *
		–	200 MW	✔ n/a	✔ *
RR	Tertiary Control	+	280 MW	✔ n/a	✔ *
		–	125 MW	✔ n/a	✔ *

* Pooled loads normally comprise distributed generation, backup generation and Demand Response, as entry levels for Demand Response alone are too high.

Table 2: List of balancing market products, including volumes and load accessibility in Austria

B. Markets open to Demand Response

Aggregation is legal and enabled particularly within the Balancing Markets. However, independent aggregation have to require the permission of the consumers BRP/ supplier to access customers.

Balancing Market

The current market rules and technical/organisational rules consider the aggregation of demand and generation resources (pooling). Austria also amended the existing framework for aggregation and Demand Response – especially the grid utilisation charges (*Netznutzungsentgelt, NNE*) have been adapted to favour the contribution of Demand Response in Austria's balancing markets, as they do not punish deviation from initial forecasts to the same extent any longer.

Capacity Market

At the moment Austria does not discuss the implementation of a capacity market in the classical sense. Existing instruments, such as congestion management, balancing market programmes and the cross-border cooperation with Switzerland, Slovenia and Germany are estimated to be sufficient[20]. However, under certain conditions, the introduction of a Capacity Market in other European countries, in particular in Germany, could result in a positive financial effect for the Austrian market.[21]

Interruptible Contract

Interruptible contracts do not exist in Austria at the moment.

[20] According to Martin Graf, Chairman of the Austrian regulator E-Control, available at: http://www.aggm.at/energy-news/e-control-energie-markt-wandel-bringt-vernetzung (retrieved on 11th April 2015)

[21] Sweco (2014): "Capacity markets in Europe", available at: http://www.e-control.at/portal/page/portal/medienbibliothek/presse/dokumente/pdfs/Studie_Capacity%20Markets%20in%20Europe_final%20February%202014.pdf retrieved on 7th April 2015)

Wholesale Market

Currently there is no Demand Response participation on the EPEX spot market from Austria, although in principle Virtual Power Plants (VPP), including demand-side flexibility, could already participate in the day-ahead market.

The combined total of German and Austrian power being traded on the EPEX day ahead market increased in 2014 by 7% to a new record high of 262’920’580 MWh. The intraday market volume also increased in the same period by 34% to 26’382’790 MWh, also an all-time high[22].

C. BRP’s agreement prior to load curtailment and other contractual needs

An independent third-party aggregator needs to inform and contract with the BRP/supplier in order to use the flexibility of Demand Response resource (for the balancing market). The aggregator is then also obliged to contract with the TSO (APG) and Demand Response providing units (for balancing market). The following delays and increase in costs, slows the deployment and lowers the participation of aggregated Demand Response in the balancing markets.

D. Imbalance settlement after load curtailment

So far, there is no standardised compensation mechanism in place for suppliers’ revenue losses resulted by a third party, which is why these have to be bilaterally negotiated.

E. BRP-aggregator adjustment mechanism

There is currently no standardised adjustment mechanism in place, which addresses the open energy position faced by the Supplier or BRP when Demand Response is initiated by a third party aggregator. Therefore all Demand Response providers need to **bilaterally negotiate** such a mechanism with the respective BRP, which creates difficulties and conflicts of interest between parties.

F. Distribution network

There were several research and development projects in Austria, which are targeting the development of the future role of DSOs. As an example, hybridVPP4DSO[23] investigates the use of a VPP for commercial trading activities combined with the technical management of the distribution grid.

[22] EPEX (2015): Press release, available at: https://www.epexspot.com/document/30189/2015-01-13_EPEX%20SPOT_2014_Annual%20 Press%20Release+.pdf (retrieved on 16th April 2015)

[23] hybridVPP4DSO (2015): Homepage, available at: www.hybridvpp4dso.eu (retrieved 12th April 2015)

2. Programme requirements

This section reviews the programme descriptions in the different markets in order to ascertain if they enable consumers to participate. Overall the results are positive and significant progress has been made between 2013-2014.

Balancing market and Ancillary Services

Enablers

With regards to the balancing market, the relevant requirements take into consideration some particularities of aggregated Demand Response. In 2014 the product requirements for the tertiary reserve were changed in order to fit consumer capabilities in a better way. For example, the minimal bid size was reduced from 10 MW to 5 MW for fully automatized activations (*AutoMOT*; put into operation in 2014 Q4). Though 5 MW is still quite a large bid size for such a small market it was a significant improvement over 10 MW and is manageable. Furthermore, the duration of the activation was reduced from 16 to 4 hours, enabling participation for a range of demand resources. A 4-hour duration, is a significant improvement over 16 hours and is possible for an aggregator to manage. However it still significantly reduces the demand-side capacity available within the Austrian markets, as it requires the aggregation service provider to pool large numbers of consumers in order to maintain the 5 MW bid over the 4-hour period. Consumers can be fully engaged when the requirement is lowered to 1-2 hours.

Barriers

There remain a few historic regulations in place which are not appropriate for consumers, these treat a single consumer as if they were a large generation unit, for example by requiring them to have a dedicated telephone line to the TSO in order to provide Demand Response services. This significantly increases the cost of participating in Demand Response for consumers, again shrinking the size of the market.

Primary Control

Primary control is tendered on a weekly basis, only symmetric bids with a minimum size of 2 MW are allowed. A symmetric bid blocks most customers from participating in this market, as a customer will often not be able to change their consumption pattern in an exactly symmetric manner. Markets open to consumers do not require that bids are symmetric.

APG cooperates cross border on primary control with the Swiss TSO Swissgrid based on a TSO-TSO model. A part of the necessary primary control reserve can be procured via the neighbouring partner-TSO. Surplus bids can be put at disposal to the partner-TSO and will be transferred into the neighbouring market if they are cheaper than the domestic bids.

Secondary Control

Secondary control is tendered on a weekly basis with 3 different time windows (weekday peak, weekday off-peak, weekend) for both positive and negative regulation. The separation of positive and negative regulation supports demand-side participation as does the 3 time windows, as this means a consumer/aggregator is able to choose and bid into the time window as is appropriate for them. There are two cooperation agreements with neighbouring countries in place for secondary reserves: the Imbalance Netting Cooperation (INC) with Slovenia and the International Grid Control Cooperation (IGCC) with Germany, which reduce the amount of activation of secondary control in Austria significantly.

Tertiary Control

Tertiary control is tendered on a weekly basis, with separate tenders for weekdays and weekends, both split into 6 four-hour windows. In addition, a day-ahead auction for the same time windows is being held, with however only an utilisation payment and no availability payment included. It should be noted that a 4-hour duration requirement, though a significant improvement over 16 hours, is still not optimal. Consumers can be fully engaged when the requirement is lowered to 1-2 hours.

3. Measurement & Verification

Prequalification

Technical & organisational rules (TOR) do not consider some of the requirements for providers of balancing services in detail. Respective rules regarding verification, monitoring and baseline will have to be adapted accordingly to cover Demand Response aggregators.

Prequalification is valid for 3 years, each balancing reserve programme requires an own prequalification process. After successful completion of the prequalification process, providers can enter into a framework agreement (for each programme separately) with the TSO, which allows them to participate in the bidding process for the respective programmes.

The official prequalification process of APG takes usually min. 3 months – depending on the quality of the submitted papers and the complexity/novelty of the used aggregation system the process could also last longer (due to additional questions or the need for clarification).

The length of the process, the fact that each programme must be pre-qualified separately and the complexity of the paperwork, all add to the cost of each consumer's participation and ensures that only the very largest customers have access to the markets either alone or through aggregation. Again this is an example of the process itself shrinking the size of the market, though it is still legally possible to consumers to enter.

Baseline methodology

The baseline definition is given in the Conditions for Pre-Qualification. [24]Anyway, specific details can be defined bilaterally with APG. The communication infrastructure used by APG in Austria for balancing power is relying on well-established but relative old standards (e.g. IEC 101). Experience showed that – from the point of view of cyber security – the risk using the IEC 104 protocol is too high (severe event covering Austria and parts of Germany in 2013).

[24] APG (2015): "Dokumentation zur Präqualifikation", available (only in German) at: https://www.apg.at/~/media/FA1843A24D1A4DDF-92313BE5CE657F13.zip and https://www.apg.at/~/media/14AEB29A7F15493FB5126B085EE3FFDB.zip (retrieved 12th April 2015)

The prices for capacity (€/MW/h) in Austria were relatively high in the past but saw a decrease in 2014. Like in Germany, also the balancing markets in Austria saw a shift of revenue/prices from capacity to energy prices. The cost of balancing power in Austria increased to about 203 million € in 2014. Especially tertiary reserve already saw some Demand Response participation, which is expected to grow further in the future.

Availability/utilisation payments

Product	Category	Availability payments[25]	Utilisation payments	Access
Primary Control	+ / –	22,01 €/MW/h	Not provided	tender-based
Secondary Control	+ Peak	7,38 €/MW/h	119,03 €/MWh	tender-based
	+ Off Peak	9,75 €/MW/h		tender-based
	+ Weekend	7,82 €/MW/h		tender-based
	– Peak	6,72 €/MW/h	-123,09 €/MWh	tender-based
	– Off Peak	14,20 €/MW/h		tender-based
	– Weekend	20,28 €/MW/h		tender-based
Tertiary Control	+ Weekdays	3,22 €/MW/h	164,09 €/MWh	tender-based
	+ Weekend	1,01 €/MW/h		tender-based
	– Weekdays	5,45 €/MW/h	-63,98 €/MWh	tender-based
	– Weekend	11,53 €/MW/h		tender-based

Table 3: Overview of availability and utilisation payments in the balancing market in Austria

Penalties

Penalties include a time-limited exclusion from the participation in the balancing markets and also monetary penalties (amount not specified; it is within the discretion of the TSO). In case of repeated non-delivery/under-performance the prequalification process has to be repeated.

The most attractive markets for Demand Response are from a technical point of view the tertiary control (relatively low entering barrier due to low technical requirements) and from an economic point of view secondary control (high prices and amount of activations).

Currently the business case for Demand Response in Austria is relatively weak. Aggregators can only attract customers with big amounts of flexible load and/or backup generation (e.g. industry) to contribute to a pool. Smaller resources are still reluctant to participate due to low revenue streams.

[25] E-Control (2015): Market price overview, weighted average over the period of W22/2013 – W21/2014, available at: http://www.e-control.at/portal/pls/portal/portal.kb_folderitems_xml.redirectToItem?pMasterthingId=2417724 (retrieved 8th April 2015)

Belgium

Overview

Belgium has taken noteworthy steps in order to open its ancillary services to Demand Response through a series of changes in the product requirements. Demand Response can participate to the Primary and Tertiary Reserves, as well as in the Interruptible Contracts programme, classified under the Tertiary Reserve. However, the Secondary Reserve is not yet open to Demand Response. Additionally, a share of demand-side capacity is participating in the Strategic Reserve, introduced in 2014 to ensure a sufficient level of security of supply during the winter periods.

The main difficulty within the Belgian market is that aggregators need the prior agreement of the customer's supplier/BRP to contract with the customer. Programme requirements generally enable Demand Response participation. Some improvements are still needed regarding measurement and verification, where some barriers block the full potential of Demand Response: for instance local energy production cannot be isolated from the available flexible power potential, or the prequalification process required by the DSO for some programmes. Payments to provide ancillary services are quite attractive and penalties are considered reasonable

The challenge for wider Demand Response participation is now to give customers easier access to the spot market. Participation in the spot market, Belpex, is currently limited only to a few large industrial consumers.

1. Consumer access & aggregation

A. Market overview

The following table shows the Belgian electricity market products, their size and underlines where Demand Response and aggregated loads can participate.

ENTSO-E's terminology	Elia's terminology		Market size	Load Access & Participation[26]	Aggregated Load Accepted
FCR	Primary frequency control (R1)	R1-200mHz	28 MW	✗	✗
		R1-Down	27 MW	✗	✗
		R1-Load(Up)	27 MW	✓ 27 MW	✓
FRR	Secondary reserve (R2)	R2-Down	140 MW	✗	✗
		R2-Up		✗	✗
FRR-M	Tertiary frequency control (R3)	R3-Prod	400 MW	✗	✗
		R3-DP		✓ 60 MW	✓
FRR-M	Tertiary frequency control Interruptible clients (R3 ICH)		261 MW	✓ 261 MW	✓
RR	Voltage control and reactive power control		2700 MVAr	✗	✗
RR	Black start		n/a	✗	✗
RR	Strategic Reserve (SR)	SGR	750 MW	✗	✗
		SDR	97 MW*	✓ 97 MW*	✓

* Additional capacity has been contracted for the winter 2014/2015, as described below

Table 4: List of balancing market products, including volumes and load accessibility in Belgium

B. Markets open to Demand Response

Ancillary Services and Balancing Market. Primary and Tertiary Reserves allow Demand Response participation, whereas Secondary Reserve does not. In addition, Demand Response represents about one tenth of the capacity involved in the Strategic Reserve. This reserve has been introduced in 2014[27] to ensure a sufficient level of security of supply during the winter periods, in the particular context of an important reduction of nuclear power generation, due to the recent simultaneous breakdown of nuclear reactors. Finally, Load flexibility is provided also through the Interruptible Contracts programme, which is dedicated to Demand Response.

DSO-connected consumers can participate in R3-DP (since 2014) and SDR as from 2015-16. Other products might open to DSO consumers in the future, though the remaining issues with the lack of transparency concerning DSO blocking of a given consumer's access put this into question (see section 3, *Measurement & Verification*).

Wholesale market. Electricity consumers can enter demand bids with indication of price in the power exchange, Belpex Spot. The participation remains low, due to remaining barriers, such as the requirement for aggregators to sign agreements with the consumer's supplier/BRP of the consumer or becoming a BRP.

[26] Elia (2015a): "Required total volumes of ancillary services for year 2015, for R1, R2, R3 and R3-ICH", available at: http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-Services-Volumes-Prices (retrieved on 15th April 2015)

[27] Belgian Government (2014): Law of 26 March 2014, art. 5, published on the Official Gazette n. 97/2014

Furthermore, the share of the electricity traded in the spot market is still low in comparison with the total market volume. The participation of demand-side resources in Belpex Spot is limited to a few large industrial players, such as steel or chemical industries, or though some operators, such as Powerhouse[28], that acts as an aggregator for smaller consumers (e.g. greenhouses, pumping stations, cold stores, etc.).

Regarding the quarter-hourly spot market, the participation has reached 17,1 TWh[29] for the Day-Ahead Market (DAM), and 0,7 TWh[30] for the Continuous Intraday Market (CIM), during 2013, which represents almost the 21% of the total electricity supplied by the TSO (80,6 TWh).

C. BRP's agreement prior to load curtailment and other contractual needs

Selling load flexibility requires signing agreements with the consumer's BRP or becoming the consumer's BRP, except R3 ICH, which does not require this. Existing arrangements are in the form of bilateral contracts. As the situation stands now, customers do not have free choice in choosing their aggregation service provider, since they have to obtain the permission of their BRP/supplier. The supplier has the legal right to refuse any cooperation with a different service provider or even renegotiate the consumer's contract for supply of electricity. For the moment, this creates significant entry barriers both for consumers and aggregators in an otherwise open market. The issue is under review by the Belgian Regulator and the framework defining the relationship between third-party aggregators and suppliers/BRPs is expected by 2016.

At the same time it is difficult and expensive for a new entrant aggregator to become a BRP, because of the associated costs, bank guarantees and the high level of penalties, which might reach the value of 4.000 €/MWh in case of imbalance.

D. Imbalance settlement after load curtailment

BRPs may experience imbalances in a perimeter where Demand Response event took place. Two solutions are used at the moment for the existing balancing products open to Demand Response, based on consensus reached with market parties for a possible compensation of the balancing perimeter of the BRP:

(1) For the TSO-connected consumers in the interruptible contracts (R3 ICH) and in the Strategic Reserve demand-side (SDR) products, the curtailed energy is added back to the portfolio of the BRP (day-ahead nomination is used instead of the actual metering) and therefore the consumer pays for the energy curtailed;

(2) For R1-Load, R3-DP and SDR 2015-16, the latter for DSO-connected consumers, the portfolio of the BRP is not corrected. This means that the consumer would pay for the energy actually consumed and the BRP is paid imbalance prices, for the energy sourced, but not delivered to his consumers. In the specific context of the Belgian imbalance prices and by the fact that curtailment is only activated when the control area is short, this means the BRP is considered to get a more than adequate remuneration for his open energy position (typically significantly above day-ahead market price).

[28] Powerhouse, RWE Group: website, available at: www.powerhouse.be (retrieved on 15th April 2015)
[29] CREG (2013): Rapport Annuel 2013, pag. 42 (retrieved on 15th April 2015)
[30] Belpex (2013): Yearly Overview, available at: http://www.belpex.be/wp-content/uploads/Belpex-2013.pdf (retrieved on 15th April 2015)

E. BRP-aggregator adjustment mechanism

Regarding electricity bought in advance and not consumed due to Demand Response, BRPs are not compensated, in the R1-Load, R3-DP and for the DSO consumers for the SDR products.. For the R3 ICH product, and TSO consumers in the SDR product, the consumer pays the energy curtailed to the BRP.

F. Distribution network

Some projects and discussions on DSO-controlled flexible sources are on-going, limited to local production, and do not yet include demand-side resources.

2. Programme requirements

The minimum size to participate in the programmes generally allows Demand Response participation, and the market conditions are in average in line with similar products. Tenderers have limited possibilities to take a speculative position in annual programmes tenders, therefore a significant up-front sales & marketing investment is required to secure customers with risks not to win a contract. This limits Demand Response potential and some improvements might be studied to design the capacity market. The following table contains an overview of the main programmes' technical requirements.

<table>
<tr><th colspan="2">Product</th><th>Minimum size (MW)</th><th>Notification Time</th><th>Activation</th><th>Triggered</th></tr>
<tr><td colspan="2">R1-Load (Up)</td><td>1 MW</td><td>15s (50%)
30s (100%)</td><td>Automatic speed, rotation and frequency control system</td><td>No limit, but reasonable number of activations per year, about 80 min/ year</td></tr>
<tr><td colspan="2">R3-DP</td><td>1 MW</td><td>15 min</td><td>Remote control</td><td>Max 40 times/year</td></tr>
<tr><td colspan="2">R3 ICH</td><td>1 MW</td><td>3 min</td><td>Remote control</td><td>Not more than 4 times/ year</td></tr>
<tr><td rowspan="2">SDR</td><td>SDR_4</td><td>1 MW</td><td rowspan="2">6,5h (warm-up) + 1,5h (ramp-down)</td><td rowspan="2">TSO's website, day-ahead forecast + intraday correction</td><td>Max 40 times/year</td></tr>
<tr><td>SDR_12</td><td>1 MW</td><td>Max 20 times/year</td></tr>
</table>

Table 5: Description of some main programme requirements concerning the balancing products accessible to DR in Belgium

Primary Reserve (R1-Load)

Demand-side resources will have to adjust their consumption only for deviations above 100 mHz, which has reduced impact on the industrial processes. The volume must be kept stable for at least 15 minutes, without interruptions[31]. The TSO offers four different types of products:

- R1-symmetrical 200 mHz (activated between -200 mHz, +200 mHz),
- R1-symmetrical 100 mHz (between the range [-100,-200] mHz and [100,200] mHz,
- R1-upwards (-200 mHz, -100 mHz),
- R1-downwards (100 mHz, 200 mHz).

Demand Response is competitive, especially because the up-regulation from generation is generally more expensive than the down-regulation. The combination of generation down-regulation and load curtailment is usually the best solution. This separation indeed halves the number of the events for each regulation and the bandwidth required to offer the service.

Tertiary Reserve, (R3-Dynamic Profile)

The duration per activation is limited to a maximum of 2 hours, with a minimum 12 hours period between two interruptions, in order to ensure consumers do not to become overburdened by multiple activations[32]. The R3-DP product is Demand Response only, but it competes with R3-Prod (generation): the 2015 tender, with a cap of 100 MW[33], ended with only 60 MW contracted, due to an aggressive bidding strategy of the largest players. Demand Response product was challenged by non-Demand Response products, and for that reason discussions are ongoing to allow a bigger share of Demand Response in 2016. The extra volume of Demand Response had the opportunity to bid into SDR additional volume in the 2015 auction.

Tertiary reserve – Interruptible Service (R3 ICH)

The programme is the other facet of tertiary reserve (R3) off-take, and it will be phased out over the coming years. There must be at least 24 hours between two interruptions. The TSO offers three possible levels of service, according to the maximum duration of an interruption:

- A4: 4 hours per call, 16 hours per year;
- A8: 8 hours per call, 24 hours per year;
- A2: 12 hours per call, 24 hours per year[34].

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[31] Elia (2002): Federal Grid Code, Arreté Royal 19 December 2002, F.2002-4675, section III, art. 242

[32] Elia (2015b): “A specific tertiary offtake reserve: Dynamic Profile” available at: http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/S-Ondersteuning-net/S_Grid%20support_En.pdf (retrieved on 15th April 2015)

[33] Elia (2014a): “Demand-side participation, Recent and Upcoming Developments”, presented at SPF Economie / IEA-DSM Seminar, 10 June 2014

[34] Elia (2015c): “Paid offtake interruption in order to preserve the grid”, available at: http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/S-Ondersteuning-net/S4_F_INTERRUPTION.pdf (retrieved on 15th April 2015)

Strategic Reserve (SR)

The 2014-2015 programme has a total capacity of 850 MW overall, whereof 750 MW of generation (SGR) constituted for a period of three years, and about 100 MW of Demand Response (SDR), contracted for one year. On top of that, a significant extra volume has been contracted for the winter 2014/2015, among the non-awarded participants in the ICH and R3-DP tenders[35]. For the winter 2015-2016, the SR size will be increased to 1500 MW, or up to 3500 MW[36] if the two missing nuclear power plants will not return to operation. In this context, at least 300 to 500 extra MW will be reserved for generation, with two year contract, and the rest will open to competition[37]. For SDR, on-site generation behind the meter is not allowed to participate because of regulatory barriers. This issue, which might require a regulatory change, is possible to be addressed to design the new Capacity Market. Regarding SDR, two sub-programmes are in place:

Programme	Maximum duration of one activation	Minimum duration of one activation	Minimum time between consecutive activations	Maximum cumulated duration in winter period
SDR_4	4 hours	1 hour	4 hours	130 hours
SDR_12	12 hours	1 hour	12 hours	130 hours

Table 6: Description of Strategic Reserves duration and activation characteristics in Belgium

Day Ahead and Intra-Day

Discussions to open the Day-Ahead and Intra-Day markets are expected this year, in parallel with the set up an energy only bid ladder platform[38] where market players can offer all available flexibility for balancing purposes.

3. Measurement & verification

Measurement provisions currently do not enable full access of customer load to market. Since volatility of local energy production (e.g. from a locally installed wind turbines) at one site cannot be isolated from the available flexible power potential on that same location, a large amount of the available Demand Response potential remains inaccessible for aggregation. This is also the case for the volatility of non-flexible energy consumption within one site that cannot be separated from the available power flexibility. As such, there is a need for "meter behind meter" provisions in the settlement process within all reserves that demand can offer to a TSO (except R1). This issue therefore causes significant Demand Response barriers within the measurement and verification criteria. The UMIG 6.0 market design, expected to take place from 2018, might lead some changes.

[35] Elia (2015d) : «Rapport sur l'avancement du développement de la capacité d'interconnexion et de la gestion de la demande», art. 2.4.3 (published on 13th February 2015)

[36] Elia (2015e): "Additional explanatory memo regarding the volume of the strategic reserve for winter 2015-2016" (notice of 11 th February 2015)

[37] Belgian Government (2015) : "Réserve stratégique en **électricité**", available at : http://economie.fgov.be/fr/consommateurs/Energie/Securite_des_approvisionnements_en_energie/reserve_strategique_electricite/#.VOGvpfnF8dn (retrieved on 15th April 2015)

[38] New programme under consideration by the TSO to allow extra generation or flexible demand to participate without the need to go through a traditional tender mechanism for reserves. Elia (2015): "Bin ladder platform", available at: http://www.elia.be/en/users-group/ad-hoc-task-force-balancing/Bid-ladder-platform (retrieved on 10th June 2015)

Prequalification

For R3-DP and in the forecast for SDR 2015-2016, the prequalification process required by the DSO limits the available Demand Response potential and hinders Demand Response sourcing efficiency. This is due to the fact that the DSOs have difficulty evaluating the potential congestion issues linked to market driven behaviour of DSO consumers and therefore tend to be cautious and discriminating towards allowing Demand Response. Currently the DSO is able to block or refuse consumer access to Demand Response without taking responsibility for the costs incurred by the consumer, aggregator and TSO, or even providing transparent measurement and risk calculation information used as a basis of the decision (in fact the DSO is not required to take accurate measurements of the risks involved). This lack of transparency and measurement requirements will become a significant barrier to Demand Response development if the issue remains unsolved.

Baseline methodology

The baseline is required at least for the control of activation of the R3 ICH (TSO level) and SDR (TSO and DSO levels) products. For R3-DP, the use of the measure of a quarter hour before the event is used as baseline[39]. Specifically, R3-DP requires the installation of an AMR meter, with 15 minutes metering, and which needs to be validated by a distribution system operators or by the TSO. Sub-metering (meter behind the meter) has been introduced for the SDR product for 2015-16, but for TSO consumers only. It will most probably also be allowed for R3 from 2016, but again only for TSO consumer. Discussions to allow the participation for DSO-connected consumers are ongoing and could drive changes from 2017. Finally, R1 is evaluated a posteriori by frequency-variation reports drawn up by the TSO, to verify the proper activation of the programme, as well as to analyse the process.

4. Finance & penalties

Availability/utilisation payments

Payments are attractive in the reserves markets. In R1 a single payment covers both the provision and the activation of the service. In R3, the auction process by the TSO sets the capacity payment, and in Interruptible Contract programme (ICH) an additional payment is rewarded per activation. SR remunerates for activation, warm up and utilisation periods.

[39] Elia (2014b): "Expert Working Group", available at: http://www.elia.be/~/media/files/Elia/users-group/Expert-WG-10122014_slides.pdf

Product	Availability payments	Utilisation payments	Access
R1-Load	5-6 €/MW/h[40]	0	Monthly tender
R3-DP	3,07 €/MW/h[41]	0	Tender
R3 ICH	1,41 €/MW/h[42]	linked to the bid prices for upward activation, minimum of 75 €/MWh	Tender
SDR	Not public	68 €/MWh[43]	Yearly Tender

Table 7: Overview of availability and utilisation payments in the balancing market in Belgium

Penalties

The penalties are in line with the accountability of supplying reserves to a TSO and can be considerate acceptable. The availability penalty of R1-Load is the 130% of the remuneration price. R3-DP has a penalty of 130% of the capacity remuneration in case of missing power. R3-ICH has a penalty of 120% of the remuneration, in case of more than 3% of missing power reserve. SR requires a penalty of 130% of the remuneration in case of unavailability, and allows a period of unavailability without penalty, in case of needed reparation or scheduled inspections[44].

[40] Elia (2014c): Tender results for 2014, average range price, available at:, http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-Services-Volumes-Prices (retrieved on 15th April 2015)

[41] Elia (2015f): Tender results for 2015, average range price, available at http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-Services-Volumes-Prices (retrieved on 15th April 2015)

[42] Ibid. (retrieved on 15th April 2015)

[43] Elia (2015g): Average utilisation payment, during a day with SR event http://www.elia.be/en/grid-data/data-download (retrieved on 19th March 2015)

Denmark

Overview

The use of Demand Response in Denmark remains quite limited. In theory, electricity consumers are allowed to participate in every ancillary service in Denmark. However, due to the regulatory environment, Demand Response participation within the markets remains limited. Demand Response aggregation takes place only through suppliers, and there are no independent aggregators in the Danish market today. The balancing programmes are mainly designed around the characteristics of generators, leading to a situation where only the largest consumption units are able to participate.

Tertiary Reserve is the most accessible programme for demand-side participation. The planned introduction of Demand-side Strategic Reserves will incentivise further Demand Response participation. However, its limited volume (20 MW) would not trigger significant business development. Furthermore, with an important share of Secondary Reserve volumes being contracted from the Norwegian TSO, Demand Response has limited room for development.

Energinet.dk, the Danish TSO, is currently working on an energy market reform proposal named "Markedsmodel 2.0". This reform aims at better integrating the large and growing share of RES through the use of flexibility and market coupling with the other Nordic countries. Introducing clear price signals is envisaged as one of possible enhancer of flexible demand. The reform is currently in its second phase, and the recommendations should be published in August 2015[45].

Aggregation is legally possible in Denmark, however the lack of clarity of roles and responsibilities between aggregators and BRP/suppliers represents an important competition issue. As in many a European countries, in order to contract with a customer, a third-party aggregator would need the prior agreement of the customer's BRP/supplier. As a result, only suppliers provide aggregation services, and in a limited manner, due to the remaining barriers.

Main enablers:

- Ancillary services are open to Demand Response;
- Prequalification is made at the aggregated pool level;
- Demand Response can participate in the wholesale market.

Main barriers:

- Programme requirements are still largely generation oriented and block demand-side resources
- Ancillary services require symmetric bids and other generation-oriented requirements;
- Third-party aggregators have to bilaterally contract with the consumer's BRP in order to provide Demand Response services;
- Payments in the wholesale market are low.

[44] Elia (2014d): "Procedure for constitution of strategic reserves", applicable for 2014 tender, art. 4.3.1

[45] Energinet.dk (2014), "Market Model 2.0. Phase 1 Report", available at: http://www.energinet.dk/EN/El/Engrosmarked/Ny%20markedsmodel/Sider/default.aspx (retrieved on 10 June 2015)

1. Market access & aggregation

A. Market overview

The Danish transmission system is divided into two areas (Western-DK1 & Eastern-DK2). DK1 is synchronous with Germany and the Continental grid, whereas DK2 is coupled with the Nordic one. A connection exists between them, called "Storebælt HVDC" (the Great Belt Power Link). This situation influences the structure and use of Demand Response in Denmark as some programmes are separate for each area.

The substantial share of Danish ancillary services is procured from neighbouring countries. As a result, it is less feasible to assess the exact volumes contracted in Denmark. The table below presents the total volumes, contracted from Denmark or neighbouring countries.

ENTSO-E's terminology	TSO's terminology	Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Reserve (DK1)	≈23 MW	✔	✔ (23 MW[46])
FRRa	Secondary Reserve (DK1)	≈100 MW	✔	✔
FCR	Frequency-controlled normal operation reserve (DK2)	≈22 MW	✔	✔
FCR	Frequency-controlled disturbance reserve (DK2)	37 MW	✔	✔
FRRm	Tertiary (Manual) Reserve (DK1 and DK2)	≈868MW	✔ (555 MW)	✔
RR	Short-circuit power, reactive reserves and voltage control (DK1 and DK2)	0 MW	✔	✔
-	Strategic Reserves (DK2)	200 MW	✔	✔

Table 8: List of balancing market products, including volumes and load accessibility in Denmark

B. Markets open to Demand Response

Balancing market and ancillary services

In Tertiary Reserve, Demand Response's participation is limited to electric boilers installed at local district heating plants. Today, 45 units with a total capacity of 555 MW are installed in Denmark. Part of these (share unknown) also participate in the Primary Reserve. This type of Demand Response is made possible by the complementary use of natural gas fired CHPs and relatively large heat accumulators, allowing for high flexibility in electricity consumption and production.

[46] Electrical boilers cover all demand for negative primary reserves (i.e. down regulation)

- **DK1.** Secondary reserve in DK1 is fully contracted from Norway, thus there is no such market for Danish players at the moment. According to Energinet.dk, a common Nordic market for Secondary Reserve is being discussed.

- **DK2.** There is a common market for Frequency-controlled normal operation reserve and Frequency-controlled disturbance reserve between DK2 and Sweden. Energinet.dk concluded also an agreement with the German TSO Tennet for a common market on Primary Reserves.

Wholesale

Consumers can trade their flexibility into the common Nordic wholesale markets (Elbas, Elspot). However, the traded volume is very limited, mainly due to low prices.

Consumers can sell their flexibility independently or via an aggregator, but in both cases the agreement of the consumer's BRP is required. This issue is currently being addressed in the discussion on "Markedsmodel 2.0. Approximately 85% of Danish electricity is traded on the Nord Pool Spot market.

Strategic Reserves

A plan to introduce a 200 MW Strategic Reserves for 2016-18, is waiting for the approval from the Danish regulator[47]. However, the specific Demand Response sub-programme will represent only 20 MW[48].

Capacity market

The possibility of introducing the capacity mechanism is being addressed in "Markedsmodel 2.0" discussion.

C. BRP's agreement prior to load curtailment and other contractual needs

Third-party aggregators have to bilaterally contract with the consumer's BRP in order to provide Demand Response services. This represents an important market barrier.

D. Imbalance settlement after load curtailment

There is currently no mechanism in place to bring the BRP back into balance.

E. BRP-aggregator adjustment mechanism

There is no standardised mechanism to compensate the electricity bought in advance by the BRP and not consumed because of a Demand Response event triggered by a third-party aggregator.

[47] Energitilsynet (2014): Strategic Reserves in Eastern Denmark, available at: http://energinet.dk/DA/OM-OS/Indkoeb/Sider/Udbud-af-strategiske-reserver.aspx

[48] p. 4, ibidem (retrieved on 10 June 2015)

F. Distribution network

Several demonstration projects have been run by utilities. Their focus is on integration of intermittent energy into the grid. For example, DONG (Danish incumbent and main utility), together with SEV (Faroe Islands' utility), created a Virtual Power Plant on the Faroe Islands, called Power Hub. It was introduced in 2012 with the aim to prevent power cuts in an isolated energy system[49].

2. Programme structure and requirements

Balancing Market and Ancillary Services

As mentioned above, Denmark is divided into two transmission areas (Western-DK1 & Eastern-DK2) influencing the structure of the market. The rules for ancillary services are mainly designed around generation-standards. For example the requirement to have an online metering system constitutes a substantial cost for any entity willing to provide its services.

Primary Reserve

In DK1, the primary reserve is an automatically operated reserve for frequency containment. It requires very short delivery time and too frequent activations for traditional Demand Response to cope with – except for some MW-scale electric boilers.

In DK2 primary reserve, the TSO requires delivery of 50 % within 5 seconds and 100 % within the next 25 seconds, thus most of Demand Response units are disqualified. For example, some back-up generators can provide 50% in 6 seconds, but this is not accepted. This requirement may change with the adoption of the European Network Codes. The frequency restoration reserve requires symmetric bidding[50]. In markets such as the UK, the requirement for symmetric bidding was removed in order to enable consumers to participate.

Secondary Reserve

Today, the Secondary Reserve Market requires upward and downward regulation/symmetrical bids[51]. Furthermore, the whole volume of Secondary Reserve is currently contracted from Norway.

Tertiary Reserve

Common rules apply to both DK1 and DK2. The main barrier consists in the high minimum bid (10 MW), this reserve being still manually operated. The Tertiary Reserve is activated through a regulating market, which is common for Nordic countries. In addition, the participation in the Tertiary Reserves Market requires a control centre operating 24/7, which represents a cost barrier for a new aggregator[51].

Strategic Reserves

The Strategic Reserves are procured through a one-off tender with participation of both consumption and production units. Both production and consumption

[49] Jessica Shankleman, Case Study: Faroe Islands reveal the secrets of successful 'negawatts', Business Green, available at: http://www.businessgreen.com/bg/feature/2227368/case-study-faroe-islands-reveal-the-secrets-of-successful-negawatts (retrieved on 10 May 2015)

[50] A requirement for symmetrical bids acts as a market barrier to consumer participation. Consumers can rarely generate and consume in equal measure. In Member states where the TSO is willing to enable Demand Response asymmetrical bids are allowed.

[51] EURISCO ApS (2013): "Activating electricity demand as regulating power. Flexpower – testing a market design proposal", p. 8, available at: http://www.eurisco.dk/images/1027_flexpower_activating_electricity_demand_as_regulating_power.pdf (retrieved on 10 June 2015)

units must provide offers on the following three cost drivers:

- availability payment per year for the volume offered;
- costs for start/stop;
- variable production costs per MWh[52].

Whereas there is a requirement of 24/7 availability for the production units, the consumption units taking part in the reserves will have to provide price flexible bids on the day-ahead market.

These programme specifications are currently under discussion in the "Markedsmodel 2.0". The following table represents the main programme requirements:

Product	Minimum size (MW)	Notification Time	Activation	Triggered
Primary Reserve (DK1)	0,3 MW	30 sec	automatic	n/a
Secondary Reserve (DK1)	1 MW	15 min.	automatic	n/a
Frequency-controlled normal operation reserve (DK2)	0,3 MW	150 sec	automatic	n/a
Frequency-controlled disturbance reserve (DK2)	0,3 MW	50% in 5sec, 50% in additional 25 sec	automatic	n/a
Tertiary (Manual) Reserve (DK1 and DK2)	10 MW (5MW from late 2015)	n/a	manual	n/a
Short-circuit power, reactive reserves and voltage control (DK1 and DK2)	*n/a*	n/a	on the spot market	n/a
Strategic Reserves	200 MW (a share of maximum 20MW is available for consumption under special conditions	Minimum 10 hours	manual	n/a

Table 9: Description of some main programme requirements concerning the balancing products accessible to DR in Denmark

Wholesale Market

In order to participate in the wholesale market, a Demand Response provider needs to sign an agreement with a BRP.

[52] p. 2, "Strategic reserves in Eastern Denmark, *op.cit.*

3. Measurement & verification

Prequalification

In order to participate in the ancillary services Market it is enough to fulfil the requirement at an aggregated level.

Participation in frequency-based ancillary services requires local frequency measurement equipment with accuracy and sensitivity of measurement being better than 10 mHz. Online metering is required by the TSO to participate in Primary and Secondary Reserve, which is costly. By default, the local DSO is responsible for the metering and for online measurements. Installation prices of €3,000 – 6,000 have been quoted for this equipment. Moreover, the participation in the Tertiary Reserves Market requires a control centre operating 24/7. The high cost of participation is particularly an issue in Denmark, where the majority of flexible loads are within the commercial sector, in relatively small sites. For this market to grow, these customers would need to be specifically enabled through low entry barriers and upfront costs.

Baseline methodology

There is no directly available baseline methodology, the lack of market transparency acting as another barrier to market entry.

4. Finance, penalties & business risks

Availability/utilisation payments

Payments are not attractive in Elspot, Elbas or in the Tertiary Reserve. Especially in Western Denmark (DK1), which is synchronous with Germany, the prices for RPM are low.

As far as Strategic Reserves are concerned, flexible bids have to be placed in five hours per day where three of the hours will have to be within 8:00 and 20:00. The bids will have to be in the price range 1000-2999,9 €/MWh. The required price range serves two purposes:

1. the maximum price has to be lower than the curtailment price at the day-ahead market (3,000 €/MWh) in order for the reserve to be activated;

2. the minimum bid price must be high enough to discourage the establishment of new consumption only to participate in the reserves, such as installation of boilers.

Finland

Overview

Finland sources a significant share of its flexibility needs from its neighbouring countries, Sweden and Norway. In 2009, due to a combination of low water levels in Norway, nuclear generation repairs in Sweden and a cold winter, three severe price spikes occurred of over 1.000 Euros/MWh. In 2010, the Energy Market Authority (Energia Virasto) ordered a study on the potential impact of lowered peak demand, during the 2009 capacity events. It was found that a demand reduction of less than 1% would have lowered prices by 500 Euros.

Finland has done several steps to allow Demand Response participation, which is today legally possible for all ancillary services. On the Demand-Side Management side, the TSO Fingrid has also contracts with the largest industrial consumers to provide emergency reserves. Active market participation of Demand Response and aggregation are possible, but limitations still exist. The contractual relationship between aggregators and BRPs remains an important barrier. Moreover aggregating loads under different BRPs' area is not allowed, even if the aggregator is able to provide BRPs the adequate information to mitigate their balancing risks. Today, aggregators operate in the frequency control, in the tertiary reserve and in the spot market, while only pilot projects participate in the secondary reserve and in the frequency normal reserve. The important minimum bid size for some products limit the full potential of Demand Response. The payments are quite attractive for the ancillary products, but with some penalisation compared to the generation ones.

1. Consumer access & aggregation

A. Market overview

All the products are legally open to Demand Response, with some limitations. However, only some pilot projects participate in the Primary Reserve normal (FCR-N), and Secondary Reserve (FRR-A). The following table presents an overview of the different programmes and their respective sizes, where public data are available.

ENTSO-E's terminology	TSO's terminology	Market size	Load Access & Participation[53]	Aggregated Load Accepted
FCR	Frequency controlled normal operation reserve (FCR-N)	140 MW [54,55]	✔ (pilots)	✔
	Frequency controlled disturbance reserve (FCR-D)	260 MW	✔ 70 MW	✔
FRR -A	Automatic frequency restoration reserve (FRR-A)	70 MW[56,57]	✔ (pilots)	✔
FRR-M	Fast disturbance reserve (FRR-M)	1.614 MW[56,57]	✔ 385 MW	✔
RR	Strategic reserves	365 MW	✔ 40 MW	✔
	Balancing Market (RPM)	300 MWh[56]	100-400 MW*	✔

* Fingrid's Estimation

Table 10: List of balancing market products, including volumes and load accessibility in Finland

B. Markets open to Demand Response

Ancillary Services and Balancing Market

All ancillary services are open to Demand Response. However, some limitation exists concerning aggregation. For instance, the aggregator needs the agreement of consumer's supplier and the aggregation of loads from different BRPs' perimeters is not allowed which reduces the full potential of Demand Response. As a consequence, consumers do not have access to Demand Response service provider of their choice, as their supplier can block consumers' access to the markets. This lowers competition around consumer centred services and significantly hampers demand-side development

Participation in Primary Reserve normal operation (FCR-N) and in the Secondary Reserve (FRR-A), is limited to some pilot projects of load curtailment. The other programmes know a wider participation. The Tertiary Reserve (FRR-M) allows the participation of disconnectable loads through long-term bilateral agreements with the TSO Fingrid. Industrial consumers are involved, such as wood processing, chemical and metal industries[57]. Demand Response represents a significant percentage of the capacity involved with approximately 400 MW[58] – about a fourth of the involved capacity and representing an increasing share during the last years. The TSO also runs three pilot projects, to enlarge the market participation. They involve controlled freezer unit for FCR-N; load shifts of Uninterruptible Power Supply devices (back-up generation) and generators controlled for the Primary Reserve disturbance (FCR-D) and FRR-M; and smart control of household loads[59].

[53] Fingrid (2014a): "Demand-side management", available at: http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Pages/default.aspx (retrieved on 15th April 2015)

[54] Fingrid (2014b): "Reserves", available at: http://www.fingrid.fi/en/powersystem/reserves/Pages/default.aspx (retrieved on 15th April 2015)

[55] Fingrid (2014c): "Tilannekatsaus varavoimalaitoksiin, nopeaan häiriöreserviin sekä kysyntäjoustoon (Status of fast reserves and elasticity of demand)", available at: http://www.fingrid.fi/fi/asiakkaat/asiakasliitteet/Kayttotoimikunta/2014/21.5.2014/Tilannekatsaus%20varavoimalaitoksiin%20nopeaan%20h%C3%A4iri%C3%B6reserviin%20kysynt%C3%A4joustoon.pdf (retrieved on 15th April 2015)

[56] NordPool Spot (2014a), Market values in Finland, calculated at sum between up-regulation and down-regulation

[57] Fingrid (2014d): "Procurement of reserves, FRR-M", available at: http://www.fingrid.fi/en/powersystem/reserves/acquiring/fastreserve/Pages/default.aspx (retrieved on 15th April 2015)

[58] Fingrid (2014e): "Demand Side Management", available at: http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Pages/default.aspx (retrieved on 15th April 2015)

[59] Fingrid (2014f): "European Utility Week 2014 Amsterdam, Pre-conference seminar, November 3rd 2014"

Furthermore, Demand Response and aggregation are allowed in the Regulating Power Market (RPM)[60], a specific balancing market managed by NordPool Spot and operated by the TSO. The RPM is a common system where bids from all Nordic countries are collected. Balancing Service Providers (BSPs)[61], have access to the RPM by signing a contract with the TSO. The TSO can source a part of its balancing resources from the RPM.

Wholesale Market

The Spot Market (day-ahead Elspot and intraday Elbas) is open to Demand Response and aggregation, but only directly from BRPs, or with an agreement with a BRP. Information related to consumers' bids into Nord Pool is not public, but Fingrid estimates that between 200 and 600 MW of consumers' flexibility participate in Elspot and up to 200 MW in Elbas. Overall and similarly to the other Nordic markets, a significant share of electricity is traded in the spot market. A volume of 53 TWh has been exchanged there in 2013 (52,7 TWh in the day-ahead market Elspot and 0,6 TWh[62] in the intraday market Elbas) which represents almost 63% of the total electricity consumption.

Capacity market

Finland has not developed a capacity market. Finland has established a Strategic Reserve mechanism, which opened to Demand Response in 2013. A capacity of 40 MW will be contracted for the next two years (in addition to the 365 MW already contracted on the generation side).

C. BRP's agreement prior to load curtailment and other contractual needs

In order to be an independent third-party aggregator, the company should register as a BRP. To obtain this status, the fee is reasonable € 200/monthly, but a bank deposit of minimum € 200.000 is required, in case of bankruptcy. Even in that case the aggregator would have to sign an agreement with the consumer's BRP. Otherwise, the aggregators can also operate as service providers for a supplier. In this case, the aggregator reaches a contractual agreement with the supplier and pools loads from his balancing group according to the contract.

Thus far, the third-party aggregators have been able to protect the suppliers from financial losses on lost energy sales, through efficient and timely communication. However, the bilateral agreement requirement severely limits the ability of the consumers to choose service providers of their preference, since it gives the possibility to the suppliers/BRPs to decide with whom and under which conditions they are allowed to cooperate.

D. Imbalance settlement after load curtailment

The BRPs do not pay for imbalances due to load curtailment, as they are settled by the TSO. The TSO corrects the curve of the BRP's area taking into account his balancing orders.

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[60] NordPool Spot (2015b): RPM Finland market data, available at: http://www.nordpoolspot.com/Market-data1/Regulating-Power1/Regulating-Power--Area1/FI/Norway/?view=table (retrieved on 15th April 2015)

[61] A market participant providing balancing services (energy and/or capacity) to the TSO

[62] NordPool Spot: respectively 2014 and 2013 values (retrieved on 15th April 2015)

E. BRP-aggregator adjustment mechanism

A scheme to compensate the electricity bought in advance by the BRP, and not consumed because of a load curtailment, is usually defined in the power purchasing agreement between the supplier/BRP and the aggregator/consumer. Either the cost is passed-through or it is included in the risk margin that the customer pays to the supplier/BRP.

This bilateral arrangement menas that customers have to rely on the good will of their supplier 'allowing them' to participate in a Demand Response programme at a reasonable cost. The law provides no consumer protection or standardised requirements.

F. Distribution network

The pilot project Smart Grids and Energy Markets (SGEM)[63] was run in 2014, to evaluate the potential of the residential dynamic Demand Response and focusing on the following five areas: Smart grid architectures and distribution infrastructure, Intelligent management and operation; Active resources; Market integration and New business models. Direct load control of about 7000 electrically heated ToU partial storage houses, in rural areas, shown a potential of about 10 MW, and dynamic load control capability was implemented in about 35 MW of full storage electrically heated houses, identifying a 14MW potential for Demand Response[64].

2. Programme requirements

Ancillary Services

Some limitations still exist in the minimum bid size for some frequency reserves and for the strategic reserve. The following table presents an overview of some of the main programmes' technical requirements.

[63] CLEEN: "Smart Grid and Energy Market" project, available at: http://www.cleen.fi/en/sgem (retrieved on 15th April 2015)

[64] VTT Technical Research Centre of Finland (2014): "Demand Response in the Nordic countries: Principles, barriers, Aggregation and Experiences", page 55

Product[65]		Minimum size (MW)[66]	Notification Time	Activation	Triggered
FCR-N		0,1 MW	3 min	Automatic out of 49,95 - 50,05 Hz	Several times per hour
FCR-D	standard	1	50% in 5s, 100% in 30s	Automatic < 49,9Hz	Several times a day
	on-off model	10	instantly	Automatic < 49,5Hz	About once a year
FRR-A		5	2 min	Automatic	Several times a day
FRR-M		10	15 min	Manual	About once a year
Strategic reserves		10	15 min	Manual	1-2 times in winter
Balancing Market		10	15 min	Market based	Several times per day

Table 11: Description of some main programme requirements concerning balancing products accessible to DR in Finland

Wholesale Market

Both day-ahead and intraday markets require a minimum size of 0,1 MW to participate. Smart meters have been almost fully deployed and suppliers are legally required to make available tariffs based on hourly prices.

These tariffs enable consumer to lower their energy bills in the short to medium term. First, the customers, by accepting volatility in prices, no longer pay the supplier's risk premium which lowers retail energy prices when averaged over an extended period of time. Consumers also have the opportunity to adapt their energy consumption over time to choose cheaper periods. That said the Finnish programmes are not always directed toward providing consumer feedback or encouraging demand-side flexibility, which would require communication technology and/or some form of home/business automation. These automation offerings are currently being developed and deployed in limited areas, such as the Helsinki region.

65 Poyry and Fingrid (2014): "Sähkön Kysyntäjoustopotentiaalin Kartoitus Suomessa (Demand Response potential, Mapping in Finland"), available at: http://www.fingrid.fi/fi/sahkomarkkinat/markkinaliitteet/Kysynt%C3%A4jousto/Fingrid_Julkinen_raportti_kysynt%C3%A4jousto_16062014.pdf
66 Fingrid (2015a): "Demand Side Management / Market Places", available at: http://www.fingrid.fi/en/electricity-market/demand-side_management/market_places/Pages/default.aspx (retrieved on 15th April 2015)

3. Measurement & verification

Prequalification

The pool of loads has to fulfil all requirements, including prequalification, as an aggregator. This is a critical enabler of Demand Response as it allows the aggregator to act as mediator for the consumer, protecting them from onerous and complex technical pre-qualification measures. Another positive enabler: there is no minimum required size for consumer participation and no technical requirements for the single unit.

Baseline methodology.

Several practical questions remain around measurement and verification. Fingrid is still actively working with market participants to solve these issues.

4. Finance & penalties

Availability/utilisation payments[67]

FCR-N (where only pilot projects participate on the demand-side) and FCR-D-standard provide only availability payments. The prices have increased for 2015, from the previous year. FCR-D-on-off-model provides availability and utilisation payments (this programme is rarely activated). FRR-M provides both availability utilisation payments. In the reserves where utilisation payments are provided, some issues regarding the aggregation of loads from different BRPs' perimeters still exist. The Balancing power market provides only utilisation payment ('pay-as-cleared'). Currently, availability fees represent about 50% of the running costs for BSP; these prices are expected to rise.

[67] Fingrid (2013): market places, average data 2013, available at: http://www.fingrid.fi/en/electricity-market/load-and-generation/Demand-Side_Management/Market_places/Pages/default.aspx (retrieved on 15th April 2015)

Product		Availability payments	Utilisation payments	Access
FCR-N		16,21 €/MW/h[68]	0	Yearly Tender Hourly Market
FCR-D	standard	4,13 €/MW/h[69]	0	Yearly Tender Hourly Market
	on-off model	0,5 €/MW/h + activation fee 580 €/MW[70]	580 €/MWh	
FRR-A		0	Hourly market + Market price	Hourly Market
FRR-M		0,5 €/MW/h[71]	580 €/MWh	Fingrid's plants Long-term contract
Balancing Market		0	Market prices	Hourly bids
Strategic reserves		not yet published	not yet published	Long-term contract

Table 12: Overview of availability and utilisation payments in the balancing market in Finland

The growing amount of variable renewable energy sources will increase the gap between price peaks and valleys in the day-ahead market, making the business case for demand-side participation more attractive and stable. Moreover, this market provides the opportunity to diversify revenue streams for consumers who are already involved in balancing schemes, thus consolidating existing participation.

Penalties

The penalties appear reasonably proportionated. In the tertiary reserves (RPM and FRR-M) and spot markets (Elspot and Elbas), they are based on the imbalance settlement price which corresponds to the Nordic balancing market price plus a small penalty set by the TSO.

[68] Fingrid (2015b): information, value for 2015

[69] Ibidem

[70] Fingrid (2014g): Market values, available at: www.fingrid.fi/en/electricity-market/Demand-Side_Management/Market_places/Pages/default.aspx (retrieved on 15th April 2015)

[71] Ibidem

France

Overview

Since the last edition of our report, the French regulator has consistently worked on opening up all ancillary service markets to Demand Response and third-party aggregators – building on a history of demand-side flexibility enabled by EDF.

Since 2003, large industrial customers have been participating in the balancing mechanism, and from 2007, the first pilots were run in order to introduce aggregated residential load to the mechanism. In 2014, for the first time an industrial consumer provided its energy reduction as a FCR or Primary Reserve[72]. This programme, together with Secondary Reserve (FRRa), is accessible to load participation since 1 July 2014.

2014 also revealed the first results of the experimental phase of the NEBEF mechanism which allows curtailed load to bid as energy directly into the wholesale electricity market. During the first year, the volume amounted to a modest figure of 313 MWh. A mild winter could be one of the reasons for such a result.

Hence, although the process is still under development, France is becoming one of the most forward thinking and active markets in Europe. Current "energy transition" legislative efforts[73], could be another enhancer for the Demand Response market. The new legislation is expected to be adopted in 2015. The capacity market for 2017 and beyond should also open new possibilities for Demand Response.

Main enablers

Balancing mechanism and ancillary services are open to aggregated Demand Response. Loads can also participate in the wholesale market via NEBEF and in the coming capacity market;

The French TSO has been adjusting programmes' requirements, to better fit the capabilities of the demand side;

The relationship between aggregators and suppliers/ BRPs has been regulated in 2013 and a standardised framework put in place.

Main barrier

Some participation requirements (for reserves) limit Demand Response participation.

[72] RTE (2014) : "Les consommateurs industriels désormais fournisseurs de services pour la fréquence du système électrique français", available at : http://clients.rte-france.com/lang/fr/clients_producteurs/services/actualites.jsp?id=9693&mode=detail (retrieved on 20 May 2015)

[73] more information about the draft law on energy transition is available on the French government's website: http://www.developpement-durable.gouv.fr/-La-transition-energetique-pour-la-.html

A. Market overview

The charts below show ancillary services and other mechanisms where Demand Response participation is allowed:

ENTSO-E's terminology	TSO's terminology	Tot. Capacity Contracted[74]	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Control (*Réglage Primaire de Fréquence*)	600 – 700 MW	✔ (≈40MW)	✔
FRRa	Secondary Control (*Réglage Secondaire de Fréquence*)	600 – 1000 MW	✔ (0 MW)	✔ (0 MW)
FRRm	Fast Reserve (*Réserves rapides*)	Max. 1000 MW	✔	✔
RR	Complementary Reserve (*Réserves complémentaires*)	Max. 500 MW	✔	✔
DSR - RR	Demand Response Call for Tender (*Appel d'Offres d'Effacement*)	2014: max. 750 MW 2015: max. 1800 MW	✔ (2014: 750MW, 2015: 1800MW)	✔

Table 13: List of balancing market products, including volumes and load accessibility in France

On the wholesale market, the experimental phase of the NEBEF mechanism (2013-2014) resulted in a load participation of 310 MWh.

The first auction of the French capacity market will be held in 2015.

[74] RTE (2009), "Documentation Technique de Référence, Chapitre 4 – Contribution des utilisateurs aux performances du RPT, Article 4.1 – Réglage Fréquence/Puissance", available at: http://www.rte-france.com/uploads/Mediatheque_docs/offres_services/reftech/24-04-09_article_4-1__v3.pdf (retrieved on 10 June 2015)

B. Markets open to Demand Response

Balancing Mechanism

Today, three programmes are open to Demand Response and aggregation:

- Demand-Side Replacement Reserves,
- Replacement Reserves,
- Frequency Restoration Reserves (manual).

Ancillary Services: Tests to enable Demand Response and aggregation (limited to sites located on the transmission network) with interim rules have started in July 2014 in:

- Frequency Containment Reserves (*Réglage Primaire de la Fréquence*)
- Automatic Frequency Restoration Reserves (*Réglage Secondaire de la Fréquence*).

Wholesale market

The test phase of the Demand Response mechanism called NEBEF ("*Notification d'Échange de Blocs d'Effacement*") took place from December 2013 to December 2014 on the wholesale market. The final rules of the NEBEF mechanism were issued on 19 December 2014[75]. The volume activated during the experimentation phase was quite modest (310 MWh), partially due to a mild winter. In 2014, the total volume traded on the Epex Spot day ahead market amounted to 67,8 TWh.

Besides, Demand Response based on retail prices has been valued based on wholesale electricity market prices for more than 40 years. France has a history of retail Demand Response programmes lead by EDF, the French incumbent utility. The programmes were based on variable retail price schemes, and EDF runs both residential and industrial load management programmes.

Capacity market

The market, due to start delivering in 2017, will be open to both generation and demand-side participation. The final rules applicable to the mechanism were issued on 22 January 2015. The product exchanged being "capacity", it will reflect only the availability of DR in the market[76]. Its effective activation will be counted through the balancing mechanism or NEBEF mechanism. This market could act as an important enabler for demand-side development.

C. BRP's agreement prior to load curtailment and other contractual needs

Since 2014, there is no need for consumers or aggregators to contract with a BRP in order to provide its flexibility to the markets (Balancing, NEBEF, Capacity mechanisms).

Participation of Demand Response to FCR and FRRa is only possible through a secondary market. For this reason, consumers and aggregators have to sign bilateral contracts with producers to sell them their products.

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[75] the list of players participating in NEBEF Mechanism is available on the French TSO' website : https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_operateurs.jsp

[76] To participate, the Demand Response operator will have to prove its ability to activate Demand Response programmes matching the capacity it claims for in its portfolio.

D. Imbalance settlement after load curtailment

The rules on the imbalance settlement are under evaluation within on-going discussions on the new law on energy transition. In the balancing mechanism, ancillary services and wholesale markets, the BRP perimeter is corrected by the TSO after the load curtailment, so that the BRP does not face any imbalance due to Demand Response.

Balancing mechanism

A standardisation is on-going.

At the transmission network level, consumers' load curves are corrected based on the energy curtailed, which is then invoiced by the electricity supplier at the retail price.

At the distribution network level, in 2014, electricity suppliers were not compensated. In 2015, the consumers will compensate the electricity supplier for the energy curtailed:

- Either based on regulated scales approved by the regulator ("regulated regime"), or
- Decided by a contractual arrangement between the Demand Response operator and the electricity supplier ("contractual regime").

Ancillary services

Participation is limited to the transmission network, where load curves are corrected based on the energy curtailed, which is then invoiced by the electricity supplier at the retail price.

Wholesale market

There are 3 different regimes for the BRP's compensation:

- Contractual regime: the compensation is decided by a contractual arrangement between the DR operator and the supplier of the site.
- Regulated regime: a financial transfer (in €/MWh) from Demand Response operator to the suppliers of the curtailed customers (the settlement) is supposed to represent only the energy component of the supplier's BRP price for the customers concerned by Demand Response programmes. The price scale is set by the TSO RTE, and is differentiated for industrial sites and households (because they have different kinds of meters). This settlement price has been introduced to ensure that the supplier/BRP of curtailed customers maintains the injection of the energy that it has sourced for its customers even if it leads to an imbalance of its perimeter and to an absence of remuneration of its customer for the energy that has been sourced and injected by this supplier.
- "Corrected consumption" regime: for consumers connected to the transmission network, the consumer's supplier invoices the electricity related to the DR event to the aggregator/consumer.

Additionally, RTE is investigating to what extent the possible shift or rebound effects caused by Demand Response could be taken into account in the settlement scheme.

Capacity mechanism

In the French capacity market, the product reflects only the availability of Demand Response in the market. The effective activations are counted through the balancing or NEBEF mechanism which include BRP's compensation mechanisms.

F. BRP-aggregator adjustment mechanism

The decree from 4 July 2014 provides for a compensation paid by the aggregators to the suppliers/BRPs for the suppliers sourcing costs (the unused electricity)[77]. The set of compensation rules includes a "regulated regime" where RTE sets a price reflecting the cost of the sourced electricity, i.e. the energy share of the retail price. The rules apply to the electricity reductions that are bid into the wholesale market and into Balancing Mechanism. Details are provided together with the imbalance settlements' rules in the section above.

The existence of a price 'per default', preventing resource-consuming negotiations, is an important enabler for Demand Response development.

F. Distribution network

ERDF runs 15 demonstration projects, aiming at testing programmes that could allow a better network management. The projects range from RES integration to evaluation of so-called active demand solutions[78]

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2. Programme requirements

As a critical enabler, all main electricity markets are open to Demand Response. Moreover, the establishment of the capacity mechanism could provide a source of long-term investment stability for Demand Response, a programme that provides predominantly a capacity service.

RTE's products are adapted to Demand Response and have been improved further to be aggregation-friendly, i.e. to allow aggregation irrespective of the type of network, metering, electricity supplier, BRP, etc. However, certain consumers with a curtailment clause in their supplier contract are blocked from participating in forms of Demand Response.

Ancillary Services

FCR (*Primary Control*) **and FRRa** (*Secondary Control*)**.** Minimum schedules for FCR & FRRa are 1MW. FCR & FRRa are mandatory symmetrical products. From July 2014 Demand Response participation (certificated consumption sites, industrial & aggregated load as participants) is limited to the transmission grid and is based on bilateral contracts[79].

RTE is considering allowing unsymmetrical products, Demand Response participation from distribution grid and more aggregation-friendly conditions in the near future.

FRRm (*fast reserves*) **and RR.** The minimum bid is set at 10 MW for FRRm and RR since April 2014. Although this is not the 1-5 MW requirement achieved in most Demand Response friendly markets in Europe, it is a significant improvement over the earlier 50 MW requirement.

[77] Décret n° 2014-764 du 3 juillet 2014 relatif aux effacements de consommation d'électricité, available at: : http://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000029190216&categorieLien=id (retrieved on 10 June 2015)

[78] more information on ERDF's website, at the following address: http://www.erdf.fr/smart-grids-ou-reseaux-intelligents (retrieved on 10 June 2015)

[79] Thomas Veyrenc, "Market design for Demand Response: the French experience", presentation of July 3, 2014, International Energy Agency, available at: https://www.iea.org/media/workshops/2014/esapworkshopii/Thomas_Veyrenc.pdf (retrieved on 10 June 2015)

Experimentation for 1-10 MW Replacement Reserve is expected in April 2015 for RR, and for FRRm in October 2015. As for the availability within FRRm, the RTE tender allows much flexibility: Demand Response to participate for certain days only (and not 24/7).

RTE activates bid volumes on the Balancing Mechanism (FRRm, RR, DSR-RR) by merit order. Generation and consumption are in competition on a level playing field. The dispatcher activates the most economic offer and also takes into account technical constraints when needed (e.g. the activation delay).

Product	Minimum size (MW)	Notification Time[80]	Activation	Triggered
Primary Control (FCR)	1 MW	<30 s	automatic	Triggered continuously
Secondary Control (FRRa)	1 MW	<15 min	automatic	Unlimited
Fast Reserves (FRRm)	10 MW	13 min	manual	Unlimited
Complementary Reserves (RR)	10 MW	30 min	manual	Unlimited
DR Call for tender (DSR – RR)	10 MW	2 h	manual (ongoing works on automation)	Up to 60 days/year

Table 14: Description of some main programme requirements in the balancing products accessible to DR in France

Wholesale market

In order to participate as a provider within NEBEF mechanism, the Demand Response operator is required to sign a contract with RTE. The declarations indicating available Demand Response volumes, are submitted by the providers one day (before noon) before the planned reduction.

Product	Minimum size (MW)	Notification Time	Activation	Triggered
NEBEF	0,1 MW	5:30 PM day ahead the latest	n/a *(acc. to bid)*	n/a *(acc. to bid)*

Table 15: Description of some main programme requirements in the NEBEF mechanism in France

[80] The figures related to notification times are available on the French NRA's webpage, at: http://www.cre.fr/reseaux/reseaux-publics-d-electricite/services-systeme-et-mecanisme-d-ajustement (retrieved on 9 April 2015)

Capacity mechanism

Demand Response operators have two options to participate in this market:

- contracting with suppliers and reducing the obligation of suppliers through Demand Response programmes,
- or going through a certification process of loads and acting independently.

Demand Response operators can choose between methods of participation and can switch from one method to another – from one delivery year to another. The peak periods both on the obligation side and on the certification side have been designed to allow Demand Response operators to participate.

Demand Response operators are able to go through the certification process closer to real time than generators. Existing generators need to be certified 3 years ahead whilst Demand Response operators need to be certified only 1 year ahead of the delivery year. Such a solution is useful for Demand Response operators at it can give them bigger flexibility as far as planning their development is concerned.

3. Measurement & verification

Prequalification

The pooled load has to fulfil requirements as an aggregate. This is a critical enabler of Demand Response as it allows the aggregator to act as mediator for consumers, protecting them from onerous technical pre-qualification measures and from costly duplication of procedures.

However, there are specific requirements according to the types of reserves, which can be difficult for the demand-side to meet. In addition, aggregation possibilities are limited (not all sites can be aggregated with other sites).

Baseline methodology

The methodology is published on the RTE's website, and requires the approval of the regulator.

In the NEBEF mechanism, there are several means of monitoring: two baseline methodologies are available (based on values just before and after the DR event, or "historical" based on longer period). RTE makes also possible actors to propose new measurement processes.

Availability/utilisation payments

The following chart provides an overview of accessible payments:

Product	Availability payments	Utilisation payments	Access
Primary Control (FCR)	160k€/MW/y for obligations. Free deals on secondary market. DSR is only on secondary market	10.43€/MWh for obligations. Free deals on secondary market.	Obligation to provide for generators (DSR participation possible through secondary market)
Secondary Control (FRRa)	Idem	Idem	Idem
Fast Reserves (FRRm)	36 k€/MW (2015-2016)	n/a	Merit order based (energy)
Complementary Reserves (RR)	21 k€/MW (2015-2016)	n/a	Merit order based (energy)
DSR-RR	10-40 k€/MW/year[81]	max 200 € or 2x spot price	Merit order based (energy)
Free bids on the Balancing Mechanism	n/a	Max 300-400€/MWh (very rare)	Merit order based

Table 16: Overview of availability and utilisation payments in the balancing market in France

Other

Premium Explicit Demand Response in the residential sector (so called "*l'effacement résidentiel diffus*") can receive a premium for the consumption reductions that they provide. In 2015, the premium is set at the level of 16 €/MWh during daytime (7-23) and 2 €/MWh during night. There is a cap of 250 GWh per Demand Response operator, indicating the maximum amount of provided electricity reductions. This premium is financed through the tax included in the electricity tariffs. However, this premium is under question as a possible subsidy and its future is unclear at this stage.

Capacity Market

The prices on the balancing market do not reveal the full value of flexibility and capacity – services provided through Demand Response. The capacity market could help to address this issue, assuming it truly enables demand-side participation. It is based on a decentralised market structure with an obligation for the supplier to buy capacity certificates up to the level of their portfolio peak consumption.

[81] Average estimates based on global budget allocated by RTE for an auction. RTE does not disclose detailed results of auctions.

Penalties

Penalties are reasonably proportionated and do not put the entire business case at risk. Controls are frequent and prevent gaming.

Bank guarantee

It is needed in all mechanisms and could be difficult for a small aggregator to secure. From 2015, RTE will start allowing Demand Response operators to have the choice between a bank guarantee and regular deposits.

Germany

Overview

Today, a significant portion of demand-side flexibility in Germany remains untapped and will remain so, until important barriers are removed.

With an announced plan to achieve 35% of renewable electricity supply by 2020 and the phasing out of nuclear power by 2022, the German energy system will integrate more and more de-centralised variable energy generation (wind, solar) as well as de-centralised energy generation by biomass and biogas, and will increase its needs in de-centralised flexibility. Situations where variable generation from wind and solar plants surpasses the general demand in the grid are expected to happen more frequently in the future.

Currently, the German market regulation creates significant barriers to most forms of Demand Response programme types, including both those provided by suppliers and independent aggregators. However, the government is aware of these barriers and is undergoing a preliminary regulatory review to facilitate change. Conclusions of this review are summarised in 'An electricity market for the energy transition'. Should the suggested changes be fully implemented, the situation in Germany will improve.

The current list of barriers include:

- the amount of pre-qualification requirements at the asset level (rather than exclusively at a pooled level);
- the measurement requirements;
- the complex generation-centred programme requirements (e.g. minimum bid size, length in time of products);
- network fees that are designed to incentivise a flat consumption pattern, hence penalise those who provide flexibility to the system;
- the obligation for a third-party aggregator to get the bilateral agreement from its potential competitor, the BRP;
- the lack of a standardized role for third-party aggregators within the market model – requiring a multitude of contractual relationships between BRPs, Suppliers and the third-party aggregators;
- no single standard, market roles not clearly defined, pooling across balancing zones.

A. Market overview

In principle, Demand Response and aggregation are legally allowed in all German balancing market programmes. The actual share of flexible demand-side loads in the overall participation is however very hard to estimate.[82]

ENTSO-E's terminology	German TSOs' terminology		Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary control reserve (PCR)	+ / –	≤ 670 MW	✔ (n/a)	✔
FRR	Secondary control reserve (SCR)	SCR +	≤ 2500 MW	✔ (n/a)	✔
		SCR –	≤ 2500 MW	✔ (n/a)	✔
mFRR	Minute reserve (MR)	MR +	1513 MW	✔ (n/a)	✔
		MR –	1782 MW	✔ (n/a)	✔
Interruptible loads	Immediately interruptible loads (SOL) – AbLaV[83]		465 MW	✔ (246 MW)	✔
Interruptible loads	Quickly interruptible loads (SNL) – AbLaV		929 MW	✔ (648 MW)	✔

Table 17: List of electricity balancing market products with volumes and load accessibility in Germany

The minimum bid size of 50 MW, combined with a maximum of 5 aggregated units per pool, makes it practically impossible for aggregated load to participate in the interruptible loads programmes.

The wholesale market and re-dispatch (incl. winter grid reserve) are closed for Demand Response. Intra-day markets are open for consumers working with their electricity supplier. There is no capacity market in Germany, but debate to introduce a capacity reserve, which, according to the design proposals in the German White Paper, will also be closed for Demand Response.[84]

[82] 50Hertz/Amprion/TransnetBW/TenneT (2015): Data for control reserve, available at: https://www.regelleistung.net (retrieved on 4th April 2015)
[83] Verordnung für abschaltbare Lasten
[84] German Ministry of Economy and Energy (BMWI) (July 2015): "Ein Strommarkt für die Energiewende", available at: http://www.bmwi.de/DE/Mediathek/publikationen,did=718200.html

B. Markets open to Demand Response

Balancing market and Ancillary Services

The programmes in the balancing market are open to Demand Response resources.

Re-dispatch is closed for Demand Response: both the continuously contracted Re-dispatch resources as well as the "winter grid reserve". These are generation-only, non-marketed programmes. The TSOs contract power plants bilaterally without going through any public auction or tendering process. The regulatory oversight is performed by the Federal Network Agency (BNetzA) and the Federal Cartell Office.[85]

Interruptible loads

Interruptible loads are defined as large consumption units which are connected to the high and extra high voltage grid, nearly continuously consume a large volume of electricity and can, when called upon, reduce or interrupt their demand on short notice and for a fixed minimum duration, thanks to the nature of their production process. In Germany, such a programme has been put in place in 2013 for an initial duration of 3 years.

Capacity market

The German Ministry for Economy and Energy (BMWi) published a Green Paper[86] in October 2014, discussing the fundamental question of whether Germany should install a capacity market or whether an energy-only market "2.0" will be sufficient. In July 2015, the BMWi published a White Paper[87] announcing the decision that Germany will not introduce a capacity market, but instead will further develop the energy-only market and complement it with a capacity reserve for the transition period ahead. This capacity reserve is open for generation only, with no access for the demand side, and initially will encompass 2.7 GW of lignite coal power plants. The legislative process with final design proposals is scheduled for autumn/winter 2015.

Wholesale market

German electricity is being traded at the European Energy Exchange EEX in Leipzig (forward market) and the EPEX SPOT in Paris (day ahead and intraday market). However, for the time being, only very large consumers participate on the spot market, and as intraday trade for Demand Response is still closed, the participation of demand-side aggregators is practically non-existing. In contrast, 3rd party aggregation of distributed generation assets, e.g. wind, biomass and biogas is a viable business opportunity, as the distributed renewable energy unit chooses a BRP to market its generation. VPP (Virtual Power Plant) providers have started to participate, but with very small amounts of Demand Response in their portfolio.

[85] For further information on the reserve power generation directive, please see BMJ/juris (2015): Reservekraftwerksverordnung – ResKV, available only in German at: http://www.gesetze-im-internet.de/bundesrecht/reskv/gesamt.pdf (retrieved on 4th April 2015)

[86] BMWi (2014): Ein Strommarkt für die Energiewende, available at: http://www.bmwi.de/DE/Themen/Energie/Strommarkt-der-Zukunft/gruenbuch.html (retrieved on 4th April 2015)

[87] http://www.bmwi.de/DE/Mediathek/publikationen,did=718200.html

C. BRP's agreement prior to load curtailment and other contractual needs

Third-party aggregation is currently very difficult in Germany, due to regulatory barriers that require independent service providers (e.g. aggregators) to ask the bilateral permission of multiple parties – including the consumer's BRP, a potential competitor – prior to offering a consumer's flexibility into the market. In total, an aggregator operating in Germany has to negotiate and sign five different contracts:

- Consumer (agreement on participation)
- TSO (prequalification (PQ), supply of reserve energy)
- DSO (agreement, report of non-availability, confirmation for PQ)
- Consumer's BRP (agreement on schedule exchange, BRP-approval for PQ)
- Consumer's supplier (agreement on payments)

A particular difficulty is the requirement to reach a bilateral agreement on schedule exchange and compensation payments with the consumer's BRP and supplier. There are no standards for this, and the BRP and supplier often have no interest in working with the aggregator to reach such an agreement. The reason for this is that BRPs/suppliers usually see the aggregator as competitor: someone who is approaching their customer to offer services the BRP/supplier may not yet be able to offer. The aggregator's dependency on the approval of a potential competitor is the single largest barrier for competition between service providers in Germany.

The BMWi White Paper published in July 2015 acknowledges the need for further clarification of the role of aggregators (measure 10).

One way to escape from these difficulties is for the service provider to work for and within a supplier. In this case the aggregator is pooling loads in one supplier's balancing group. Though in principle it is positive to see Demand Response services offered by suppliers, this limitation hinders market growth by lowering competition.

D. Imbalance settlement after load curtailment

After curtailment (as part of positive balancing reserve):

1. The aggregator sends information to the BRP, on the basis of the bilateral agreement.
2. The balancing group settlement is processed through a "day-after" schedule exchange.
3. The aggregator sells the curtailed energy to the TSO (as positive balancing energy).

The consumer's BRP sells the same amount of energy to the aggregator in order to correct both its own and the aggregator's balancing perimeter.

The aggregator must pay the BRP/supplier for the energy curtailed during a Demand Response event, on the basis of their commercial agreement. There is no standard or regulatory oversight of such agreements, so the supplier and BRP set the prices.

E. BRP-aggregator adjustment mechanism

A standardised adjustment mechanism does not exist in Germany. Several European countries have put in place adjustment mechanisms addressing the open energy position faced by the Supplier/BRP when Demand Response is initiated by a third-party aggregator (e.g. France, Switzerland). Thereby, they have enabled the unbundling of retail and Demand Response services, and allowed for effective competition for Demand Response. This is not the case in Germany, where retail and Demand Response aggregation activities are still effectively bundled by the market model.

F. Distribution network

As in most European countries, possibilities for DSOs to invest in Demand Response are very limited. Currently there are no programmes operating on the distribution level, with the exception of controlled overnight heating. This is partly due to the fact that the incentive regulation favours CAPEX over OPEX, hence it is better from a DSO perspective to expand its network (and thus increase its capital base) than to contract with a Demand Response provider. Nevertheless, this possibility is being discussed within the energy industry associations and the regulator (BNetzA) is considering various models for a future incentive regulation.

2. Programme requirements

Balancing Market and Ancillary Services

Programme requirements act as a barrier for the development of Demand Response in Germany.

Primary Control Reserve

Suppliers of PCR need to prequalify with each TSO in whose area the prospected reserve will be offered. A prerequisite for completion of the Master Agreement is the successful prequalification of a unit with a performance at least equal to the minimum bid size. The current volume of 670 MW includes 67 MW from the Netherlands and 25 MW from Switzerland, who both bid in the same pool of PCR.

Secondary Control Reserve

Secondary reserves are tendered on a weekly basis, requiring a BSP to estimate available resources more than 10 days in advance. Consumers participating in SCR, however, risk potential increases in grid tariffs for deviations from their normal (flat) energy consumption profile, which constitutes a significant financial disincentive for offering their flexibility in this market.

Minute Reserve

Minute reserves are tendered on a daily basis for positive and negative regulation in 6 four-hour time windows for the following day. Two main challenges exist for the participation of Demand Response in the Minute Reserve programme: positive Minute Reserve faces a historical oversupply by 50-100%, although this figure seems to diminish with the overall decrease of residual load. Consumers participating in Minute Reserve also risk potential increases in grid tariffs for deviations from their normal (flat) energy consumption profile, which constitutes a significant financial disincentive for offering their flexibility in this market.

Product	Minimum size (MW)	Notification Time	Activation	Triggered
PCR	1 MW	30 sec	Automatic	Up to several times per day
SCR	5 MW	5 min	Remote-controlled	Up to several times per day
MR	5 MW	15 min	Automatic activation by Merit Order List Server	Up to several times per day

Table 18: Description of some main programme requirements in the balancing products accessible to DR in Germany

Enablers

Minimum bids for all balancing programmes have been downsized in 2011 and 2012, making them more accessible for Demand Response[88]. Minimum bids do not exceed 5 MW, except for the Interruptible Load programme (AbLaV – "Verordnung für abschaltbare Lasten") where the threshold is still set at a prohibitive 50 MW[89]. As a result, prices have been decreasing, which reveals the broader range of offers now available.

Barriers

Reserve power requires the ability to be activated for a duration of 4 hours for Minute Reserves and 12 hours for Secondary Reserves (up to 60 hours over the weekend) whereas the service is normally only required for much shorter periods and the reserve power concept foresees secondary reserve to be replaced by minute reserve within much shorter timeframes. Markets such as Austria, Belgium, the Nordics, and the UK have lowered the required activation period in order to allow demand-side resources to compete. German Demand Response participants do manage to operate in both reserves, by relying on larger pools and backup generation assets. However, the resource remains significantly repressed due to these requirements.

Those providing demand-side flexibility may face higher network fees, often removing any business case for Demand Response. The network charging regime incentivises consumers to maintain a regular, standardised consumption profile, damaging the business case for flexibility. It also gives discounts to large consumers that remain above a certain "full load hour" level. Such consumers, when providing negative reserves (that is increasing electricity consumption), risk losing these discounts and paying significantly higher network charges, even when the negative reserve energy is provided to the TSO for system balancing reasons. A similar effect can occur with the provision of positive reserves where the total consumption may fall below the required threshold, due to the provision of balancing services to the TSO. The structure of the network fees constitutes a severe barrier and restricts the participation of energy-intensive

[88] 50Hertz/Amprion/TransnetBW/TenneT (2015): Minute reserve, available at: https://www.regelleistung.net/ip/action/static/ausschreibungMrl (retrieved on 18th April 2015)
[89] 50Hertz/Amprion/TransnetBW/TenneT (2015): ibidem

industrial consumers in the balancing market. This has been acknowledged in the recently published BMWi White Paper, and changes to these rules have been announced.

Another barrier is the pre-qualification process itself, which can take many months, or in extreme cases up to a year at times when TSOs have limited resources to deal with (sometimes large amounts of) pre-qualification requests. This unpredictability makes it challenging for consumers and their service providers to develop a reliable business case.

Interruptible loads (AbLaV)

Through AbLaV, the legislator made it possible for TSOs to contract directly with interruptible loads that can help to maintain grid and system security[90]. The German TSOs issue a call for tender each month for 1,500 MW of immediately interruptible loads (SOL), with a response time of less than 1 second, and an equal volume of quickly interruptible loads (SNL), with a response time of less than 15 minutes. Payments for availability are fixed at €2,500/MW per month, and payments for activations are between €100-400/MWh.

Not even half of the offered tender volume is being tendered for so far, due to the very strict eligibility criteria. The minimum bid size of 50 MW, combined with restrictions on aggregation and very rigorous requirements on the consumption profile that only allows a few seconds of deviation per month, create significant entry barriers for consumer participation. Only a very small number of large consumers can technically participate. The AbLaV programme is due to end on 1 January 2016 and is currently being considered for extension.

3. Measurement & verification

Prequalification

Several pre-qualification tests are required at an individual asset level: a significant barrier to consumer participation as each small consumer site is treated as if they were a 500 MW generation unit. This is significantly limiting participation, as many loads/assets that would provide valuable contributions to a pool through their specific capabilities, cannot pass the pre-qualification stage on their own. Given that it is the pool delivering the services to the TSO, it should be the pool that is pre-qualified, not the individual assets/loads within the pool. Many neighbouring countries have moved to pool-level pre-qualification, such as France, Switzerland and Austria.

Pre-qualification also has to be done with each of the 4 German TSOs separately, increasing the cost and time required. As the market structures in Germany are unified it is illogical that the pre-qualification results cannot be shared between the TSOs.

[90] With the amendment of the Energy Industry Act (EnWG) of 20 December 2012 and by means of the "Ordinance on Interruptible Load Agreements (AbLaV)".

Baseline methodology

An unofficial baseline definition is agreed bilaterally between the aggregator and all 4 TSOs, although this information does not appear to be public and is not equally available to all Demand Response providers.

The definition should become a standard across Germany and be published in a transparent manner. This will require further effort on the part of the regulatory bodies, in particular the BNetzA. Currently not only is the baseline not standardised between the BRP and Demand Response provider but also among the different BRPs or between them and the TSO. This results in costly duplication of data exchange operations, which could be simplified or even centralised by the TSO, as it is the case in Switzerland.

4. Finance & penalties

There is a growing gap between the continuously low wholesale market prices and the much higher balancing market prices in Germany. The gap is regularly exceeding a factor of 100, due to the fact that large amounts of renewable energy generation are available within the intra-day markets. This has damaged the business case for flexible generation – mainly gas fired power plants – as they are moved out of merit. On the other hand, growth in variable generation drives increasing demand for balancing services.

Availability/utilisation payments

The primary reserve programme provides availability payments only. Secondary and Tertiary reserves programmes provide availability and utilisation payments. Bids are accepted following the merit order list of availability prices. During activation, the merit order list of utilisation prices applies. In particular for the negative SCR there is a wide range of accepted utilisation prices, of which the higher end is rarely called. All payments are issued pay-as-bid. Secondary and negative Minute reserves appear to be the most attractive for now.

Great Britain

Overview

Great Britain (GB) was the first country to open several of its markets to consumer participation in Europe. Today, all balancing service markets are open to Demand Response and aggregated load is accepted. However, unfortunately in recent years it seems that the stakeholder process between providers, DECC and Ofgem has not been as effective as would be expected in a mature market. As a result, measurement, baseline, bidding and many other procedural and operational requirements are inappropriate for demand-side resources, noticeably reducing the number of demand-side MWs in the system (even as national capacity continues to decline). Therefore, though the markets remain open in name, the actual results are worse in 2015 than in 2013-14. If the trend continues the UK will no longer be a viable market for demand response providers.

The BRP and Aggregator issue is not yet resolved in GB. However, as the aggregator is not required to contract directly with the supplier/BRP, this lack of clarity has not yet had an adverse impact on the market. In future, it will be important to clarify this relationship for the fairness of all involved – including the supplier/BRP.

The Capacity Market, introduced at the end of 2014, does not place demand-side resources on an equal footing with generation. In fact, only one demand-side aggregator, of the approximately 15 in the market, secured a contract within this new market in the first Capacity Market auction. (This design is in fact under question within the European Court of Justice[91]. The outcome of the case is unknown at the time of publication of this report.)

As National Grid is under growing 'distress' because of the growth of embedded generation, interconnection and large transmission-connected renewables, and also DNOs encouraging more innovative products, the opportunity for Demand Response is in principle higher than ever. However, due to poor policy development and design choices, that opportunity cannot be realised.

1. Consumer access & aggregation

A. Market overview

All balancing market programmes in Great Britain are open to Demand Response, however there is no data available as to the share of Demand Response in the various programmes. Aggregation is possible in all the programmes and is especially needed in those programmes with high minimum bid sizes. The only dedicated programme for Demand Response is the Demand-Side Balancing Reserve (DSBR), which was introduced last winter.

[91] Only 1 Demand Response provider was allowed to participate by DECC in the Capacity Market Design Committee, which met for over a year to design the market, while 13 generation representatives were included. Therefor the design bias is not surprising.

ENTSO-E's terminology	National Grid's terminology		Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Firm Frequency Response (FFR)[92]	Dynamic	180 MW	✔ (n/a)	✔
		Non-Dynamic	0 MW	✔ (n/a)	✔
FRR	Fast Reserve Firm Service (FRFS)*[93]	Dynamic	2313 MW	✔ (n/a)	✔
		Non-Dynamic	54 MW	✔ (n/a)	✔
RR	Short-Term Operating Reserve (STOR)[94]	Committed	2420.6 MW	✔ (n/a)	✔
		Flexible	757.7 MW	✔ (n/a)	✔
RR	Demand-Side Balancing Reserve (DSBR)		318.7 MW	✔ (n/a)	✔
FCR	Frequency Control by Demand Management (FCDM)		Not public	✔ (n/a)	✔

* The very high frequency of activations (10-15 per day) makes it practically impossible for DR to participate

Table 19: List of balancing market products, including volumes and load accessibility in Great Britain

B. Markets open to Demand Response

Balancing markets and Ancillary services

The programme with the greatest historical Demand Response participation is the STOR programme. Though STOR spurred Demand Response development in 2011-12, the incumbent STOR programmes no longer support Demand Response participation. Prices have fallen and those demand-side resources which cannot be available for the whole duration of the participation window (usually 11-13 hours per day) have been devalued in terms of their tendering competitiveness. Demand Response now represents a limited part of this reserve. For example, during the Season 8.3, load curtailment represented less than 10% of the overall STOR participation. Two new variations, STOR Premium Flexible and STOR Runway, have been designed to provide better opportunities for Demand Response aggregation in STOR.

Two new balancing service pilots have been developed to support National Grid in balancing the system and address tightening capacity margins until 2016. The new services are Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR). DSBR is a Demand Response opportunity, targeted at large energy users who volunteer to reduce their demand during winter weekday evenings between 4 and 8 pm in return for a payment. SBR is targeted at power stations that would otherwise be closed and is close to Demand Response. Capacity margins are expected to tighten after 2016, and National Grid has recently consulted on whether to extend DSBR for two further years. Even if it is extended, it will still be a short term, dead-end opportunity, which does not represent a good bridge to the capacity market.

Fast Reserve Firm Service (FRFS), & Frequency Control Demand Management (FCDM) allow for aggregated Demand Response participation, but its participation is limited mainly due to requirements that it is difficult for consumers to meet (see next chapter).

92 All accepted tenders active in January 2015
93 All accepted tenders active in January 2015
94 Data for STOR year 8 – weighted average capacity over all 6 seasons

Wholesale market

Demand Response currently only directly participates in the British Day-ahead and Intraday markets in the form of flexibility of suppliers and large industrial customers that are already trading members.

There are two main power exchanges in Great Britain: APX and N2EX. UK power futures exchange traded contracts are also available on the Intercontinental Exchange (ICE). In 2012, around 85% of power was OTC traded (down from 95% in 2011), a trend that is set to continue slowly.

Capacity market

Aggregated Demand Response has access to the Capacity Market in theory, although in practice participation rules are considered to be strongly biased in favour of generation. At the time of writing, the issue of State Aid approval of the Capacity Market is in the European Court.

C. BRP's agreement prior to load curtailment and other contractual needs

The aggregator is not required to ask for permission or to inform the supplier prior to load curtailment and has direct access to consumers. They may aggregate load from all over the country. The consumer, however, is contractually obliged to inform the supplier about the intended participation. In the future, these rules will need to be formalised and legislation introduced which allows third-party aggregation while protecting the supplier/ BRP from sourcing losses and imbalance payments caused through a Demand Response activation by a third-party aggregator.

D. Imbalance settlement after load curtailment

Concerning BRP's imbalances caused by the load curtailment, the customer has no obligation to maintain a consumption profile and British legislation does not address this issue. However, as the market develops further it will be necessary in GB, as it is now in France and other markets, to define the roles and responsibilities of the BRP and BSP (aggregator or consumer) in such a manner that the costs are reasonably and fairly allocated.

E. BRP-aggregator adjustment mechanism

Due to the number of incumbent suppliers and the relatively low participation of Demand Response in general, Ofgem has so far not seen any urgent need to elaborate such an adjustment mechanism. However, Ofgem has indicated its intention to investigate the BRP and aggregator roles and responsibilities at a later date, likely addressing items C, D and E.

F. Distribution network

Ofgem's approach to incentivising network innovation supports demand-side measures when these are cost-efficient:

Under the 'Totex' approach to regulation in distribution price control 5 (2010-15), innovation measures are treated on a par with capital investment;

Network Innovation Competitions, especially the Low Carbon Network Fund (about £500m over five years)[95];

The current Distribution Price Control (2015-23), under the new regulatory framework RIIO-ED1, is based on innovation & specific outputs, obliging all DNOs to initiate or adopt Active Network Management.

Recently implemented and continuously revised regulation mechanisms create the necessary incentives for network companies to introduce smart grid solutions, a dynamic that helped Great Britain attain thought leadership and become a frontrunner in levels of investments in this sector.

As a result, five out of the six DNOs are currently running Demand Response trials. Trials in the Thames River Valley and in Bristol involve a few dozen commercial buildings each, with a large scalability potential, but do not provide any payment to the end customer. Other trials involve the use of new commercial contracts for large customers (>100kVA) or seek avoidance of network reinforcements through smart voltage control in major substations.

2. Programme requirements

Balancing Market and Ancillary Services

The chart below outlines some of the key requirements for participation in the balancing market programmes in Great Britain.

Product	Minimum size (MW)	Notification Time	Activation	Triggered
FFR	10 MW	n/a	Automatic	Up to several times per day
FRFS	50 MW	2min	Automatic	10-15 times per day
STOR	3 MW	4h	Manual	Up to several times per day
DSBR	0.1 MW	2h (can be less)	Manual	Never[96]
FCDM	3 MW	2sec	Automatic	n/a

Table 20: Description of some main programme requirements in the balancing products accessible to DR in Great Britain

[95] Though the Low Carbon Network Fund has had some difficulty in attracting a satisfactory amount of commercially viable projects, partially due to the lack of payments to consumers for providing demand side flexibility.

[96] In the pilot delivery period November 2014 – February 2015

Short Term Operating Reserve

The STOR programme requirements are challenging for consumers, as they require daily weekday participation, with a window of 11-13 hours per day, in order to be paid at a competitive level. It is possible to choose one time window (morning/evening), but it involves an important devaluation of the resource, lowering revenues. National Grid hardly ever calls STOR Flexible: due to undercutting across several tender rounds, initially accepted Flexible rates have turned out to be too high. STOR TR prices fall distinctly between TR-6 and TR-3, meaning that only tenders at least one year ahead are really economically attractive. Another significant barrier is the long period of time between contracting a site and obtaining first payments. STOR Runway, a new option, will shorten this period, as National Grid will accept tenders for volumes that have not yet been fully "created" and qualified. This allows aggregators to "grow" their pool with financial guarantees, a positive step forward.

Firm Frequency Response

FFR is open to Demand Response providers, with a minimum capacity of 10MW, in both dynamic and non-dynamic profiles. Dynamic is where generation or consumption output will rise and fall automatically in line with the system frequency. Static is where an agreed amount of energy is delivered if the system frequency hits a certain trigger point e.g. 49.8Hz.

Fast Reserve Firm Service

The FRFS programme requirements are very stringent, making it difficult for consumers to participate. It requires a 50 MW minimum bid size. Incremental additions are a minimum of 10 MW for each bidding unit. Coupled with a frequency of 10-15 activations per day, FRFS is not an attractive product for Demand Response.

Demand Side Balancing Reserve

Ofgem granted National Grid permission to introduce a new demand-side pilot product for two years from winter 2014/2015. It offers businesses an opportunity to reduce their electricity use during times of high demand (in the window between 16:00 and 20:00 on weekday evenings in the winter) in return for an utilisation payment plus an upfront payment for set-up and optionally for administrative costs (the latter only for units involving 50 or more meter points). Customers participating as part of an aggregated portfolio must be under contract and enabled in order to be eligible for tender. A very short application period of only 5 weeks in the first tender round for the 2014/2015 delivery period made it very difficult to gather sufficient market intelligence and customer support for this programme.

Frequency Control by Demand Management

The FCDM programme is used to manage large deviations in frequency, such as those caused by the sudden loss of a large generating unit. FCDM is triggered at a static set point of 49.7Hz and therefore there are few events per year. There were nine events in 2013 and nine in 2014, always with a maximum duration of 30 minutes. The service is a route to market for demand-side providers, and is entirely managed through bilateral contracts between potential providers and National Grid.

Capacity Market

Despite the fact that a special transitional system was introduced for Demand Response units and distributed generators, with two auctions in 2015 and 2016, the overall design of this market does not offer a level playing field. For example, new generators will be eligible for 15-year capacity agreements, whereas Demand Response providers will only be eligible for one-year capacity agreements. In the T-4 auction, a mere 0.4% of total capacity has been awarded to Demand Response[97]. A legal case has now been submitted to the

[97] Auction results available at: https://www.gov.uk/government/statistics/capacity-market-location-of-provisional-results

European Court on the grounds that this market does not comply with the EU competition law.

Through the 2014 T-4 Capacity Market auction, the UK government has procured 49.26GW of capacity at a clearing price of £19.40kW. This will cost a total of £0.96bn (in 2012 prices). The capacity requirement for the first delivery year, 2018/19, is 53.3 GW, of which 50.8 GW was procured in the December 2014 T-4 auction. The remaining capacity will be procured in a T-1 auction one year ahead of delivery, if needed[98]. The Capacity Market also includes a Transitional Arrangements (TA) opportunity for the purpose of building new Demand Response and distributed generation capacities, which is to include the procurement of only these resources via an auction process for delivery in the two years (2016/2017 and 2017/2018) preceding the first delivery year of the Capacity Market. The first TA auction will be in January 2016. Though demand-side resources have access to the Capacity Market in theory, the rules have not in practice enabled participation – see below discussion of business risks.

Triad Charges

Triads, or formally – Transmission Network Use of System (TNUoS) charges – are three half-hour periods on three different days separated by at least 10 days (the triad periods), that electricity demand is at its highest across GB. They were established to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. The triad days occur between November and end of February. Customers' average consumption in each network zone over the 3 triad periods is calculated, and then it is multiplied by the triad charge. This gives the total amount that supplier needs to pay to National Grid. Customers receiving pass-through charges pay their share based on average consumption during the three highest peak triad periods. Service providers may send triad warnings to their customers about 20-30 times annually, up to one day in advance, by e-mail, text message or other devices in order to warn them of a possible peak triad period. Lowering the triad charges brings good value for load flexibility.

3. Measurement & verification

Prequalification

Prequalification takes place at the pooled assets level. Signing a STOR framework agreement can take between 2 weeks and several months. In the capacity market, procedures seem straightforward, however the mandatory provision of a credit cover for new (i.e., unproven) Demand Response poses a significant barrier to potential participants. A change to regulations, providing longer deadlines for credit cover submissions, is part of the current consultation process[99]. DR units will need to complete a metering assessment before the delivery year, as well as a metering test if required.

Baseline methodology

Baseline methodologies vary by market and product. No one methodology works for all types of Demand Response, and under current rules, some methodologies favour customer generation over load curtailment. In some other cases, the methodology does not accommodate certain types of Demand Response

[98] More information on the T-4 Capacity Market Auction 2014 in the Auction Monitor Report, available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/391622/t4_cm_auction_2014.pdf

[99] See Government response to consultation: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/412934/Government_Response_to_Feb_2015_consultation_on_amendments_to_the_CM_Reg.pdf

(e.g. the Capacity Market baseline methodology for Demand Response does not accommodate CHP type resources; the latter is eligible but devalued). Added to the programme structure issues described above, participation in Fast Reserves requires a new IT system adapted to Demand Response, which represents a high cost for aggregators.

4. Finance & penalties

Availability/utilisation payments

Product	Availability payments	Utilisation payments	Access
Short Term Operating Reserve (STOR)[100]	£1.33/MW/h Committed £0.60/MW/h Flexible	£164/MWh Committed £100/MWh Flexible	tender-based
Firm Frequency Response (FFR)[101]	£4.99/MW/h	£4.55/MW/h	tender-based
Fast Reserve Firm Service (FRFS)[102]	£3.67/MW/h	£0.94/MW/h (positional fee)	tender-based
Demand Side Balancing Reserve (DSBR)	Not provided*	£250-12500/MWh (£2400/MWh) [103]	tender-based
Frequency Control by Demand Management (FCDM)	>£4/MW/h	Not available	bilateral contracts
Capacity Mechanism (CM)[104]	£19.4/kW/y	Not provided	tender-based

* Providers can request Setup and Administration (for pools of more than 50 meter points) payments

Table 21: Overview of availability and utilisation payments in the balancing market in Great Britain

The current imbalance (or 'cash-out') prices, which market participants have to pay when generating or consuming more or less electricity than they have contracted for, are not creating the correct signals for the market to balance. This could increase the risks to future security of supply and undermine balancing efficiency, unnecessarily increasing costs.[105]

DSBR utilisation payments tend to be relatively high as these resources are not expected to be utilised. Additionally, DSBR payments are determined in relation to the Value of Lost Load (VOLL) (i.e. the cost to the UK economy of black-outs).

100 National Grid (2015): STOR results for TR 9 and 10, available at: http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Short-Term-Operating-Reserve/Short-Term-Operating-Reserve-Information/ (retrieved on 20th March 2015)

101 average prices for all accepted tenders active in January 2015

102 average prices for all accepted tenders active in January 2015

103 weighted average of TR1 (winter 2014/2015) in brackets

104 T-4 auction result from December 2014

105 See Ofgem's Electricity Balancing Significant Code Review: Ofgem (2015): Electricity Balancing Significant Code Review, available at: https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review (retrieved 18th March 2015)

Capacity Market

Despite the fact that the Capacity Market included the Transitional Arrangements, intended specifically to help develop Demand Response in advance of the Capacity Market, with year-ahead auctions in 2016 and 2017, the overall design of the Capacity Market does not offer a level playing field[106]. Importantly, participation in the TAs is restricted to those Demand Response resources that have not participated in the Capacity Market T-4 auctions, and customer loads that participate in the TAs are barred from the first three T-4 auctions. Demand Response participants are forced to make choices on whether to participate in the uncertain TAs or forego the TAs and secure commitments in the Capacity Market via the preferred T-4 auction mechanisms. Aggregators that take on an obligation in any of the first three T-4 auctions may face difficulty when populating the Demand Side Units, as all customers who have participated in the TAs, even with another aggregator, will be disallowed.

Penalties

In STOR, failure to provide at least 90% of contracted capacity (defined in more particular terms as Events of Default) result in reduction of availability payments or eventual termination of a contract.

For DSBR, units that fail to deliver more than 75% of their contracted quantity during a dispatch or sample test are subject to a performance test. Repeated failure in a performance test may result in termination of contract and forfeiture of upfront payments.

In the capacity market, depending on the programme, the level of guaranteed availability for delivery is set between 75-90%. Penalty for non-delivery is 1/24th of the relevant auction's clearing price, adjusted for inflation. A cap is set at 200% of a provider's monthly capacity revenues. An overall annual cap of 100% of revenues means participants cannot lose more than they are paid.

[106] NERA Economic Consulting (2014), The Potential Impact of Demand-Side Response on Customer Bills, Prepared for EnerNOC, Kiwi Power and Open Energi, available at: http://www.nera.com/content/dam/nera/publications/2014/PUB_Anstey_DSR_0814.pdf

Ireland

Overview

While balancing market programmes still remain closed to Demand Response, Ireland has seen increasing Demand Response activities in recent years. Having phased out its main Demand Response scheme in early 2013, Ireland's TSO, Eirgrid, is providing incentives to Demand Response providers to enrol as Demand Side Units (DSU). Enrolment makes them eligible for capacity payments in the Single Electricity Market (SEM). The first DSU became operational in July 2012; the second in December 2012.

There is room for optimisation in the prequalification procedure for DSUs, whereas the interruptible loads programme STAR (Short-Term Active Response) is adequately designed.

With a rapid expansion of wind energy and a target of 40% renewable energy in electricity generation by 2020, the system's need for flexibility is set to increase in the following years. Further business opportunities will be created with the opening of the balancing markets for DSUs in the coming years.

The Commission for Energy Regulation and the Utility Regulator of Northern Ireland are currently developing an Integrated Single Electricity Market (I-SEM), intended to be implemented by late 2017. The detailed design is still under consideration, but they have settled on a volume-based capacity market, using reliability options. The I-SEM will replace many of the structures described here. The result could be better or much worse for Demand Response than the status quo, depending on some of the elements of the detailed design which have not yet been decided.

1. Consumer access & aggregation

A. Market overview

A DSU consists of one or more individual Demand Response sites that can be dispatched by the Transmission System Operator (TSO) as if it was a generator. Individual Demand Response sites may be aggregated to be operated as a single DSU. Eirgrid issues dispatch instructions at an aggregate level and the DSU aggregator then coordinates the reduction from the individual Demand Response sites. By being available for dispatch the DSU will be eligible for capacity payments in the Single Electricity Market (SEM).

ENTSO-E's terminology	Eirgrid's terminology		Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Operating Reserve		n/a	✗	✗
FRR	Secondary Operating Reserve		n/a	✗	✗
RR	Tertiary Operating Reserve		n/a	✗	✗
RR	Replacement Reserve	Synchronised	n/a	✗	✗
		De-Synchronised	n/a	✗	✗
Interruptible loads	STAR		n/a	✓	✓
Price-based capacity provision	DSU		7,046 MW[107]	✓	✓

Table 22: List of balancing market products, including volumes and load accessibility in Ireland

B. Markets open to Demand Response

Balancing Market

Ancillary services are still closed to Demand Response. A multi-stage consultation process through a review of System Services has been completed by the TSOs and the regulators are analysing recommendations. In its recommendations to the regulator, Eirgrid proposes that the services should be technology-neutral. New products are expected as well: ramping margins would be maintained to counter wind volatility by procuring Ramping Capacity[108]. At the moment, the results of this consultation process are expected to enable Demand Response in the Balancing Market by 2017.

Wholesale Market

Demand Response participates in the wholesale electricity market from the point of view of bidding and dispatch, however Demand Response providers do not earn an energy payment for this. Participation in the wholesale market is required to earn capacity payments in the capacity market.

Interruptible Contracts

Eirgrid's STAR scheme provides short-term reserves to the transmission grid, using under-frequency relays at industrial sites. Providers of this service can expect 10 to 20 unplanned and instantaneous interruptions per annum typically of the order of 5 minutes duration.

Capacity market

A volume-based capacity market does not yet exist in Ireland. Ireland has established a price-based capacity provision in the wholesale market, with a fixed cap of total payments being split across the year into each half-hour window. Prices per half-hour vary throughout the year, and eventual payments are then split between all capacity providers that subscribed their capacity for this particular half-hour. There is 80% accuracy in upfront capacity calculations, with wind forecasting having the strongest influence on uncertainty.

[107] CER (2014a): Total Capacity requirement for 2015, available at: http://www.allislandproject.org/GetAttachment.aspx?id=229e36bd-411a-4a88-8140-f0a43068ad70 (retrieved on 20th February 2015)

[108] For a description of these products, see: Eirgrid/SONI (2012): "DS3: System Services Consultation – New Products and Contractual Arrangements", available at: http://www.eirgrid.com/media/System_Services_Consultation_Products.pdf, p. 25-27. (retrieved on 24th March 2015)

C. BRP's agreement prior to load curtailment and other contractual needs

The aggregator works as a service provider for demand sites gathered to fulfil the DSU requirements. He does not have to ask for permission or to inform the supplier or BRP prior to load curtailment. The aggregator can aggregate load from anywhere in the country. They are treated as a part of the consumer's unpredictable behaviour. The SEM is currently an ex-post settled market. Suppliers do not take a position in advance and are not a BRP. All energy is settled ex-post.

D. Imbalance settlement after load curtailment

Neither the BRP nor the aggregator is charged for the imbalances caused by the load curtailment. The Irish electricity market is centrally dispatched, which means that the imbalances are covered by the TSO. When Demand Side Units are dispatched by the TSO, the demand site supplier has avoided costs (imperfections, capacity charges, Mechanism Operated Contacts) for the demand reduction quantity.

E. BRP-aggregator adjustment mechanism

There is no commercial loss for the supplier in the case of load curtailment. As a centrally dispatched market, the Irish market does not require the supplier to plan demand in advance. No such adjustment mechanism is currently needed.

F. Distribution network

Currently there is not much activity on the distribution network level. However, this is likely to change in the near future with a strong involvement expected from DSOs.

2. Programme requirements

Capacity market

Once they have filled the Demand Side Unit (DSU) requirements, consumers or aggregators are treated like generators in the market. DSUs that are available for demand reduction are eligible for a capacity payment in the Single Electricity Market (SEM). They bid in prices and quantities for demand reduction and receive availability payments[109]. However, DSUs do not receive an utilisation payment. About €530 million was available in total in the capacity market in 2013 for availability payments. DSUs participate in this market. The Energy market is valued at €2.1 billion[110]. Aggregators must provide a minimum of 4 MW bids, but there is no minimum size for individual units in the pool.

[109] The payments are based on 'value' of capacity (month, trading day and trading period). Payments are given for each ½ hour of every day (assuming availability) and vary significantly for a given trading period - from zero to €181.

[110] SEM-O (2013): SEM Market Overview, July 2013, available at: http://www.sem-o.com/Publications/General/SEMO%20Market%20Overview.pdf (retrieved on 20th March 2015)

Product	Minimum size (MW)	Notification Time	Activation	Triggered
DSU	4 MW	n/a	Manual	Up to several times per day
STAR	none	2 seconds	Automatic	10 – 20 per year

Table 23: Description of some main programme requirements in the balancing products accessible to DR in Ireland

Enablers

The minimum bid size of 4 MW and the permission of aggregation for DSUs allows for Demand Response participation (though due to the small market size a minimum of 1 MW would be a significant improvement over the current 4 MW requirement).

The STAR scheme has no minimum bid size, making it very accessible for consumption units. However a careful cost-benefit analysis should be made for small units, as the installation costs for all equipment has to be covered by the unit's owner.

Barriers

The balancing market is still closed to Demand Response. Moreover, the prequalification process for DSUs has to be fulfilled on an individual assets level (see below).

3. Measurement & verification

Prequalification

The individual units of each pool of loads have to fulfil all technical and prequalification requirements. Therefore aggregators are not able to shield consumers from these technical and difficult prequalification procedures: each consumer is treated as if they were a large generation unit. This is a critical barrier to consumer participation as it forces providers to go through onerous technical pre-qualification measures, which they may not have the ability or knowledge to fulfil. This prequalification is also very costly and might even get worse in the years to come, with the opening of the balancing market programmes to Demand Response. Prequalification should be carried out at the pooled level to avoid this issue.

Baseline methodology

As of today, a meter-before/meter-after system is used and no common baseline methodology has been agreed upon. This is inadequate. Nevertheless, a group has been created to discuss the issue in cooperation with the TSO.

Availability/utilisation payments

Product	Availability payments	Utilisation payments	Access
STAR[111]	Not provided	8,20 €/MWh*	fixed
Powersave[112]	n/a	0.38 €/kWh (off-peak) 0.95 €/kWh (peak)	fixed
DSU / capacity provision	81.60 €/kW/year[113]	Not provided	tender-based

* Supplemental rates of 1.74€/MWh – 6.97€/MWh, depending on excess number of interruptions

Table 24: Overview of availability and utilisation payments in the balancing market in Ireland

Penalties

In case of repeated under-performance or non-delivery a Demand Response aggregator faces license restrictions from the Commission for Energy Regulation (CER) and/or Utility Regulator of Northern Ireland.

[111] Eirgrid (2015): Payments and charges, available at: http://www.eirgrid.com/media/2014_2015_HarmonisedAncillaryServiceStatement%20_of-Payments_and_Charges.pdf (retrieved on 20th March 2015)

[112] CER (2013): Proposed 2013/2014 rates, available at: http://www.cer.ie/docs/000776/cer13216b-powersave-consultation-paper.pdf (retrieved on 20th March 2015)

[113] CER (2014b): Total CPPS (Capacity Period Payment Sum) for 2015, available at: http://www.allislandproject.org/GetAttachment.aspx-?id=229e36bd-411a-4a88-8140-f0a43068ad70 (retrieved on 20th March 2015)

Italy

Overview

In the recent years, the electricity market has been characterized by a rapid growth of renewable generation and by a decrease of electricity consumption. Italy relies mostly on hydro and gas for its flexibility needs, while the framework for consumer participation in the balancing market is not yet in place. The only exception is the interruptible contracts programme, which is a dedicated Demand Response programme separate from the balancing market. As Demand Response is not yet legal in the frequency reserves, here are overviewed only the rules of participation in the Interruptible Load Programme. The enrolment of interruptible loads is currently about 4 GW, with a minimum size of 1 MW to participate. Aggregation is not allowed. The payments are attractive and related mostly to availability payments rather than real utilisation. The programme has been called very few times during the last years, or never in some cases.

Flexibility can access the day-ahead market, but only as demand bids with indication of price, as dispatching user (BRP). Tenders to access the new capacity market, initially planned for the coming years, are expected to start at the end of 2015. The publication of the capacity market's rules, in the coming months, will reveal if a fair competition between loads and generation has been put in place.

The possible opening of balancing products to demand-side resources could lead to an increase of load participation. The potential progress is reflected in the strategic guidelines for the period 2015-2018, in which the Italian NRA (AEEG) included the evaluation of demand-side mechanisms, for further market development[114].

1. Consumer access & aggregation

A. Market overview

The following table shows the electricity market product or sub-products and underlines where Demand Response and aggregation could participate, including related market sizes.

[114] AEEG (2014a): "DCO 528/2014/A, consultation document", published on 30 October 2014, available at: http://www.autorita.energia.it/allegati/docs/14/528-14.pdf

ENTSO-E's terminology	TERNA's terminology		Market Size	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Frequency Control		1,5% of the total installed power	✗	✗
FRR	Secondary Frequency Control		4,77 TWh[115]	✗	✗
RR	Tertiary Reserve		8,99 TWh	✗	✗
	Interruptible (Mainland)	Fast	3.300 MW	✓ 3.300 MW	✗
		Emergency	0 MW	✓ 0 MW	✗
	Interruptible (Islands)	Fast	389 MW Sicily 372 MW Sardinia[116]	✓ 389 MW Sicily 372 MW Sardinia	✗
	Capacity Market		Not yet defined	✓	Not yet defined

Table 25: List of balancing market products, including volumes and load accessibility in Italy

B. Markets open to Demand Response

Balancing market

Market participation is not yet allowed for load curtailment, and consequently for aggregators. Primary Frequency Control is an uncompensated service, mandatory for non-intermittent generators bigger than 10MW[117]. Secondary Frequency Control and Tertiary Reserve are paid services, but not open to load curtailment. The NRA considers starting by the end of 2015 identifying market entry barriers and possible changes in the programmes in order to enlarge participation. In this context, load participation could be evaluated, though this remains unclear.

Interruptible Contracts

The participation is allowed for consumers with a minimum available curtailment potential of 1 MW, for each site[118]. Aggregation is not allowed. Interruptible Loads, managed by the Italian TSO (Terna), are trigged after a TSO's order and have to react almost instantly (200 ms). Some conditions vary between the mainland Italy and the insular Italy (Sicily and Sardinia). Specifically, in the mainland Italy, all the capacity has been already contracted for 3 years, starting from 2015. New entrants are only provided access in case of some participants' withdrawal.

115 AEEG (2014b): "Report 428/2014/I/eel, annex A", of 7 August 2014, art. 9.1, 2013 values, available at: http://www.autorita.energia.it/allegati/docs/14/428-14.pdf

116 Terna (2013): Action results for the period 2013-2015

117 Terna: "Allegato A15 Codice di Rete, Partecipazione alla regolazione di Frequenza e frequenza-potenza (Grid Code, Annex 15, Participation to frequency and to frequency-voltage control)", art.4, available at: http://www.terna.it/LinkClick.aspx?fileticket=TwRReqwHbvk=

118 Terna (2015a): "Regolamento per l'approvvigionamento a termine delle risorse interrompibili istantaneamente e di emergenza nel triennio 2015-2017 (Regulatory framework for the period 2015-2017)", art.2, available at: http://www.terna.it/linkclick.aspx?fileticket=6Df1L3TC-JsA%3D&tabid=663

Aggregation is not allowed, but participation is allowed for Consortium, which is a legal association of private companies or public bodies (i.e. agricultural associations, associations of public bodies, etc.)[119]. In that case, the Consortium manages all the energy needs for its members and could be interpreted as a different form of aggregation. However, only two Consortiums were awarded for the 2015-2017 tender[120] .

Wholesale market

Flexible consumers can access the spot market, in a single or aggregated form (as dispatching user), with demand bids with indication of price[121]. The participation is still low but has risen slightly. The context of raising economic constraints could explain this growing interest for limiting energy costs. Participants entered offer for 46,5 TWh in 2013 of which only 5,9 TWh were accepted.

In 2013, a significant share of electricity has been traded on the spot market. Excluding the bilateral contracts, almost 230 TWh of electricity have been exchanged, 207 TWh in the day-ahead market and 23 TWh in the intraday market, which represent almost the 70% of the electricity consumption[122].

Capacity market

In 2014, the NRA approved a new regulation for the capacity market in order to replace the previous temporary framework[123]. The market, tender-based, will be administered by the TSO with a first auction expected in the end of 2015. In this regulation, the NRA underlined that the demand-side resources should be able to access this market from the first auctions. The final rules would have to be closely monitored to prevent any form of prejudice to demand-side resources.

C. BRP's agreement prior to load curtailment and other contractual needs

This section is not applicable as Demand Response does not have access to the balancing market and aggregation is illegal. In the specific case of Interruptible Load Programme, to participate, a consumer is required to be a BRP or have an agreement with a BRP (*dispatching user* in that case)[124].

D. Imbalance settlement after load curtailment

This section is not applicable as Demand Response does not have access to the balancing market and aggregation is illegal. Regarding the Interruptible Load Programme, the imbalances are directly corrected by the TSO.

[119] Terna (2015), ibid.

[120] Consorzio Lattiere Virgilio Soc. agr. (agricultural) with 2MW, and Consorzio Toscana Energia Spa. (public bodies of Tuscany Region) with 211MW, Terna: "Auction results Fast Interruptible Contracts, period 2015/2017", Ibid.

[121] Italian electricity market is divided into 6 market zones: North, Central North, Central South, South, Sicilia and Sardegna

[122] AEEG (2014c): "Report 428/2014/I/eel, annex A", Ibid., art. 8.1, and GME (2013): "Annual report 2013", available at: http://www.mercatoelettrico.org/En/MenuBiblioteca/documenti/20141029_AnnualReport_en.pdf

[123] Ministry of Economic Development (2014): GU 158/2014, 10 July 2014 (Italian Official Gazette), Decree 30 June 2014

[124] Terna (2015c): "Contratto tipo per la regolazione del servizio di interrompibilità istantanea (Framework Interruptible Loads)", premise (j), available at: http://www.terna.it/LinkClick.aspx?fileticket=79I33oECozE%3D&tabid=106&mid=468 (retrieved on 15th April 2015)

E. BRP-aggregator adjustment mechanism

This section is not applicable as Demand Response does not have access to the balancing market and aggregation is illegal. Regarding the Interruptible Load Programme, there is no specific provision to balance potential open energy position of the BRP.

F. Distribution network

As in most European countries, programmes run by the DSOs are still limited or in a pilot phase. Some pilot projects seek to evaluate the potential of Demand Response at DSO level. "Enel Info+[125] " is an energy efficiency project carried out by ENEL Distribuzione. It was initially set up in Isernia Province from 2012 to 2014 and involved some thousands of LV consumers. The participants received an energy monitoring kit including a specific device called "Smart Info" which enables easy access to energy consumption data and, at a later stage, facilitates involvement into Demand Response programmes. Enel Info+[126] has been launched in 2015 in L'Aquila Province and in Apulia within the scope of smart city projects.

Moreover, an energy management system (EMS)[127] has been implemented for the Universal Exposition 2015 by ENEL Distribuzione in partnership with Siemens, in order to offer advanced energy management services to the pavilions and exposition areas. Consumption data are collected by Smart Info and other services like the management of some devices or information through user-friendly interfaces for the energy managers and the visitors are enabled.

Other projects dealing with Demand Response were carried out such as "Address", "Advanced" or are ongoing such as "Flexiciency"[128]. Other pilot projects are run by other DSOs, such as "Smart Domo Grid"[129], by A2A Distribuzione.

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[125] ENEL (2015a): "Enel Info+Infopiù", available at: http://eneldistribuzione.enel.it/it-IT/Pagine/enel_infopiu.aspx (retrieved on 10th June 2015)

[126] This device can be plugged in any socket to collect the certified data managed by the smart meter through power-line. ENEL (2015b): "Smart Info", available at: http://eneldistribuzione.enel.it/it-IT/smart_info_domanda_attiva (retrieved on 10th June 2015)

[127] ENEL (2015c): "Sistema Ems", available at: http://eneldistribuzione.enel.it/it-IT/sistema_ems_domanda_attiva (retrieved on 10th June 2015)

[128] ENEL (2015c): Ibidem

[129] A2A (2015): "Progetto Smart Grid Domo ", available at http://bilancio.a2a.eu/it/2012/bilancio-sostenibilita/la-responsabilita-sociale/i-clienti-citta-dini-servizi/commercializzazione-elettricita-gas.html?page=7 (retrieved on 10th June 2015)

Balancing Market

As mentioned above, the requirements for participation in the balancing market do not explicitly take into consideration some particularities of aggregated Demand Response, though these may be under review in future. The current requirements give access only to generation units (e.g. symmetric bidding). The following table contains an overview of the programmes' technical requirements:

Programme		Minimum Size (MW)	Notification Time	Activation	Triggered
Interruptible contract (Mainland)	Fast	1 MW	200 ms	After TSO request	No limit
	Emergency	1 MW	5 s	After TSO request	No limit
Interruptible contract (Islands)	Fast	1 MW	200 ms	After TSO request	No limit

Table 26: Description of some main programme requirements in the balancing products accessible to DR in Italy

Interruptible Contracts

In the mainland Italy, the yearly volume for the period 2015-2017 has been reduced from 3.900 MW to 3.300 MW[130]. Two sub-programmes are managed by the TSO: Fast Interruptible and Emergency Interruptible. This latter is triggered only in case of under participation in the Fast Interruptible tender. Different programme conditions apply for Sicily and Sardinia, where the previous scheme is still in force for the period 2013-2015. Interruptions are called by the TSO, with no limit of activation. The number of calls is not public, but activations can be estimated at only few times per year.

Spot Market

Flexible consumers can make demand bids with indication of price. They should belong to the same market zone[131], and bid a minimum of 1 MWh. The participation fee is € 7.500, for the registration to the platform, and €10.000 as yearly fee, plus some variable costs over the electricity traded[132].

[130] AEEG resolution 566/2014/R/eel, 13 November 2014

[131] Italian electricity market is divided into 6 market zones: North, Central North, Central South, South, Sicilia and Sardegna

[132] GME (2015): "Corrispettivi (Fees)", available at: www.mercatoelettrico.org/en/Mercati/MercatoElettrico/corrispettivi.aspx (retrieved on 15th April 2015)

3. Measurement & verification

Prequalification

Participation in the interruptible contracts requires the compliance with the Grid Code, as well as the presence of a smart meter with a remote control, triggered by the TSO. The compliance with the requirements involves significant investments and the TSO can proceed with site-inspections, or documentation verification. However, the level of participation in the last tender by single consumers was good, and fulfilled all available budget expected for the fast contracts.

Regarding the Balancing market, the possible participation of demand-side resources would require a control centre operating 24/7, which is a market entry barrier. The rules regarding verification and definition of baseline are not explicit yet.

Baseline methodology

To participate to the interruptible contract, a consumer must have a minimum load equal to its bid load, corrected by a monthly factor. The correction factors, defined by the TSO, vary between 1 and 0,9 (for January, August, October and December) and were a bit increased for the period 2015-2017, in comparison with the previous rules.

4. Finance & penalties

Availability/utilisation payments

From 2015, the maximum bid values of the Interruptible Contracts have been reduced of 10% in the mainland Italy[133]. This change, combined with the programme size reduction, aims to save about € 140 million per year according to the Ministry plan. Furthermore, a higher reduction occurred during the 2015-2017 tenders, when the results appeared to be significantly under the maximum bid price. The overall expenses are about € 300 million for mainland, and about € 230 million for islands. The following table summarises the economic conditions to participate in the in the interruptible programmes:

[133] AEEG (2014): "Resolution 566/2014/R/eel" art.8, available at http://www.autorita.energia.it/allegati/docs/14/566-14.pdf

Product		Availability payments	Utilisation payments	Access
Interruptible contracts (Mainland)	Fast	89.899 €/MW in average[134] (135.000 €/MW, tender cap)	extra 3.000 €/MW for each additional interruption, if the number of interruptions is >10, or paid back if the number of interruptions is <10[135]	Tender-based
Interruptible contracts (Mainland)	Emergency	no unassigned resource in the fast interruptible contracts tender (90.000 €/MW, tender cap)		Tender-based
Interruptible contracts (Islands)	Fast	≈300.000 €/MW in average (300.000 €/MW, tender cap)	extra 3.000 €/MW for each additional interruption, if the number of interruptions is > 20.	Tender-based

Table 27: Overview of availability and utilisation payments in the balancing market in Italy

Payments for capacity market are not yet defined, but the availability payments are expected to be set at around 25.000 €/MW.

Penalties

The agreement between the TSO and the Interruptible Users is withdrawn in case of more than 3 failures of interruption during the period 2015-2017, or in the case where the consumer's load would be reduced under 70% of the contractual load[136].

134 Terna (2015): "Tender results, period 2015-2017", Ibid.
135 AEEG (2014): "Resolution 301/2014/R/eel" 20 June 2014, art. 4, available at: http://www.autorita.energia.it/allegati/docs/14/301-14.pdf
136 Ibid., art.3.3

The Netherlands

Overview

The Netherlands presents an interesting model, as the TSO seems to have succeeded in enabling a good amount of demand-side flexibility with relatively simple market structures, namely clear and timely price signals – particularly to green-house owners. This is positive and offers an opportunity to enable further market development through encouraging market competition between service providers.

In 2014, there were no significant changes in the state of Demand Response in the Netherlands. Tennet, the Dutch TSO, estimates that currently up to 1 GW of flexibility (including demand and supply) might be present in the Dutch market. The total volume of balancing energy activated by the TSO per year presently stands at 500 GWh.

The balancing market plays a central role in the Dutch electricity system. The main drivers for demand-side participation is imbalance management of BRPs for their own portfolios and so-called "passive balancing", which presents the advantage of simplicity, but prevents third-party aggregator to access consumers directly.

In 2015, a variation of Emergency Power programme, called "Omgekeerd Noodvermogen", is starting to operate[137]. This will allow upward and downward regulation, accessible also by loads.

Main enablers

- Demand Response can access the majority of ancillary services;
- Bidders are free to state condition for the activation;
- Minimum volumes in ancillary services are adequate for Demand Response capabilities.

Main barriers

- The aggregators can participate in the market only through BRPs.
- The minimum contracted volume in the Emergency Power programme is 20 MW, which constitutes an entry barrier for potential providers.

[137] NL Noodvermoogenpool (2014): "Noodvermogen Afregelend", available at: http://nlnvp.nl/Nieuws (retrieved on 13 March 2015)

A. Market overview

The table below gives an overview of the programmes used by Tennet in order to balance the Dutch network:

ENTSO-E's terminology[138]	TSO's terminology	Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Control (*Primäre Regeling*)	weekly procurement	✗	✗
aFRR	Regulating Capacity (*Regelvermogen*)	300 MW, yearly procurement; Additional voluntary bids per ISP (15 mins)	✓	✗ (portfolio product, presumably no load involved)
mFRR	Reserve Capacity (*Reservevermogen*)	Voluntary bids only, per ISP (15 mins)	✓	✓
mFRR	Emergency Power (*Noodvermogen + Omgekeerd Noodvermogen*)	350 MW[139]+ 150 MW, yearly procurement	✓	✗ (>230 MW industrial load and aggregated resources)
RR	Replacement Reserves	n/a, traded on the intraday market	✓	✓

Table 28: List of balancing market products, including volumes and load accessibility in the Netherlands

B. Markets open to Demand Response

The biggest share of demand-side flexibility is used in "passive balancing/passive contribution". It is based on voluntary contributions from BRPs to balance the grid, without being actively selected via a bidding ladder. In case of a short or long market, the BRPs can be rewarded for their imbalance – instead of being punished for it as it may happen in other countries – if their position contributes to the balancing of the whole network. Such solution is possible due to publicly available near real-time imbalance positions and prices[140]. The aggregators typically pool demand-side resources from greenhouses, hospitals, small industries with CHP and load shedding capabilities.

[138] Elia (2014): "Potential cross-border balancing cooperation between the Belgian, Dutch and German electricity Transmission System Operators", p. 4, available at: http://www.elia.be/~/media/files/Elia/users-group/141008_Final_report.pdf (retrieved on 14 March 2015)

[139] Energie Keuze (2014): "Tennet zoekt nieuwe leverancier noodvermogen na wegvallen 100 MW", available at: http://www.energiekeuze.nl/nieuws.aspx?id=1926. (retrieved on 14 March 2015)

[140] "In the Dutch imbalance management system control area imbalance positions and imbalance price are made public in near real-time. Therefore all market participants have the opportunity to voluntarily contribute to the TSO's efforts in maintaining the system balance. This so called 'passive contribution' is believed to result in a substantial reduction in the required control energy." TenneT (2011): "Imbalance Management TenneT Analysis report", p. 14, available at: http://www.tennettso.de/site/binaries/content/assets/transparency/publications/tender-of-balancing-power/imbalance-management-tennet---analysis-report.pdf (retrieved on 15 March 2015)

Balancing Market and Ancillary Services

Demand Response and aggregation are allowed in Frequency Restoration Reserves (FRR) – automatic and manual (it includes Regulating, Reserve and Emergency Power), and in Replacement Reserves. Primary Control does not allow load access and aggregation.

In the Regulating/Reserve Power scheme, large electricity consumers (> 60 MW) are required to make their flexibility resources available to the TSO[141]. All other parties can do so on a voluntary basis. Bidders are free to state the conditions for activation. These include automatic activation or scheduled products, activation time and bid price. The TSO then accepts the bids according to its needs.

Moreover, Tennet contracts complementary FRR in the Emergency Power scheme (manual, directly activated) annually, (350 MW) which can be utilised up to 40 hours per year and with a maximum of 8 hours for a single call[142]. New variation, allowing downward regulation, will be added to the programme in 2015 and is planned to amount up to 150 MW. Use of Emergency Power is increasing, from 19 times in 2013 to 27 times in 2014.

Wholesale

The wholesale market is a portfolio market for buying and selling energy and any Demand Response offer can be bided into the wholesale market.

Replacement Reserves

are traded on the intraday market; they are not activated by the TSO.

In 2013, 48% of the total Dutch load was traded via Power NL Day-Ahead Market[143].

Congestion management

The programme, introduced by Tennet in 2008, aimed at distributing limited amounts of transmission capacity. In case of expected congestion, a participant (generator) could offer to refrain from injecting electricity into the grid, in exchange for payments. However, the programme is not currently active and does not include the possibility for consumers to reduce consumption for the same payment.

Capacity market. The introduction of the Capacity Remuneration Mechanism (CRM) has been discussed, however no firm decision has been taken yet.

C. BRP's agreement prior to load curtailment and other contractual needs

In the Netherlands, competition over demand-side services is not enabled. The offering is always bundled with the sale of electricity. Consumers must either reject the entire service or accept the aggregator's/ BRP combined offer, or try to re-negotiate their entire retail contract with another supplier in order to access Demand Response services they required.

Aggregators in the Dutch Market offer portfolio optimisation services to BRPs, through trading on the day-ahead, intraday and balancing markets. BRPs optimise imbalances through real-time dispatch and may act as balancing service providers. BRPs can act as aggregators or they can hire a third-party aggregator for this service.

[141] Tennet (2012): "Implementation Guide", available at: http://www.tennet.org/english/images/120214%20SO%20SOC%2012-xxx%20Uitvoerings-regels%204%202%20%20UKclean_tcm43-19026.pdf (retrieved on 14 March 2015)

[142] Ioannis Lampropoulos et al.(2012), "Analysis of the market-based service provision for operating reserves in the Netherlands", p. 3, available at: http://www.e-price-project.eu/website/files/EEM%5C'12%20-%20I.%20Lampropoulos%20et%20al.%20[31-03-2012].pdf (retrieved on 15 March 2015)

[143] APX Holding BV (2014): "Annual Report 2013", p 11, available at: http://www.apxgroup.com/wp-content/uploads/APX-Group-Annual-Re-port-20131.pdf (retrieved on 15 March 2015)

In this context, a third-party aggregator is obliged to have an agreement with the consumer's BRP and with its supplier. The aggregator can only work as the BRP's service provider. As in other Member States, this creates a market entry barrier for new entrants.

D. Imbalance settlement after load curtailment

Within the Frequency Restoration Reserve the TSO activates demand-side resources offered from BSPs. When load curtailment is taking place, the TSO updates the BRP's balance status in order to avoid any imbalances caused by the requested volumes.

In the other balancing markets, aggregation is limited to the BRPs portfolio optimisation, therefore the settlement process does not require any adjustment. As it was already stated, most of Demand Response events are performed on the market (*passive balancing* – within the BRPs own portfolio) and will either result in a change of commercial schedules between BRPs (BRPs trading lack and excess of loads), or ultimately in imbalances to be settled with the TSO.

The imbalance settlement price is established every 15 minutes and acts as a real time market signal which incentives BRPs to balance the system, and not only their own portfolios. This does not require the direct involvement of the TSO as the price acts as a balancing signal.

E. BRP-aggregator adjustment mechanism

For the time being, aggregators can only work as the supplier/BRP's service provider. Therefore no such mechanism is in place.

F. Distribution network

There are few experimental projects run by DSOs, focused on electricity storage or use of smart technologies. For example, a pilot called Powermatching City[144] in Hoogkerk near Groningen aims at verifying smart grid functions in real-life circumstances. Households participating in the programme have access to different types of renewables, together with smart meters and smart household appliances.

USEF (Universal Smart Energy Framework), another project, is intended to provide access to smart energy systems to all interested parties through a market-based control mechanism[145].

The Congestion management programme was introduced by Tennet in 2008. In case of expected congestion, generators could offer to limit injections of electricity into the grid, in exchange for payments. However, the programme is not currently active and is not open to demand-side participation.

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144 More information available at: http://www.powermatchingcity.nl/site/pagina.php?
145 More information available at: http://www.usef.info/Home.aspx

Balancing Market and Ancillary Services

FCR

Primary Reaction is tendered on a weekly basis. The participants should have a framework agreement signed. It is a symmetrical product and therefore blocks most demand-side units from participating.

aFRR

Regulating Capacity is contracted through yearly procurement, spontaneous bids are also possible. Minimum size of a bid is 4 MW. Submitted bids are selected in a common merit order.

mFRR

Reserve Capacity is procured through voluntary bids. It is divided into Reserve Capacity for balancing purposes and for other purposes; the latter serves for re-dispatch and is not a part of balancing market.

Emergency Capacity

Noodvermogen is contracted annually via tenders in May/June. Since 2014, it is procured separately for downward and upward regulation, allowing consumer loads to participate. The contracted volume has to be provided within 15 min., and shall be available nearly 24/7 (required availability amounts to 97 – 100%). The minimum contracted volume is 20 MW[146], it can also come in an aggregated form[147]. The Emergency Capacity is therefore difficult to enter for new entrants as the 20 MW minimal load required acts as a significant barrier to participation.

Replacement Reserves

Replacement Reserves are not used for balancing purposes and are self-dispatched, through the intraday market. This programme uses a pay-as-bid pricing system.

Product			Minimum size (MW)	Notification Time	Activation	Number of activation
FCR	Primary Reaction		1MW	Max 30 sec	Automatic	permanent
aFRR	Regulating Capacity		4 MW	30sec	Automatic	Per 4 seconds
mFRR	Reserve capacity	For balancing purposes	4 MW	next ISP	Manual	Per activation
		For other purposes	4 MW	5th ISP	Manual	
mFRR	Emergency Power	20 MW 15 min			Manual	27 per year (2014)

Table 29: Description of some main programme requirements in the balancing products accessible to DR in the Netherlands

[146] Tennet (2013): "Memorandum to Suppliers Emergency power", available at: http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/EN-GELS-SO-SOC_13-056_Productinformatie_noodvermogen.pdf (retrieved on 13 March 2015)

[147] Tennet, "Noodvermogen", available at: http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/Publications/Other_Publications/plugin-120521_Brochure_noodvermogen_tcm43-20672.PDF (retrieved on 14 March 2015)

Prequalification

The pooled load has to fulfil requirements as an aggregate. This is a critical enabler of Demand Response as it allows the BRP-aggregator to act as mediator for the consumer, protecting them from onerous technical pre-qualification measures, which they may not have the ability or knowledge to fulfil.

Baseline methodology

Baseline settlement depends on the contractual relationship between the end consumer, its BRP and its supplier. The absence of standardised requirements can act as a barrier as each contract must be negotiated individually. For TSO contracted FRR (manual) the BSP is required to supply measurements directly to the TSO[148]. The data regarding actual baselines is only required for aFRR (continuously, 4 seconds-based) and Emergency Power (checked ex post, taking into account the values 1 hour prior to activation to 1 hour after deactivation, with 5 min metering resolution).

[148] Metering is a liberalised market in the Netherlands, the meter data is managed by the meter data manager. The required metering equipment for important connections (superior to 3 * 80 A) is a telemetric meter, with (at least) 15 minutes resolution. For smaller connections there is no such obligation; allocation of realized volumes then will be based on profiling.

Availability/utilisation payments

The table below presents payments provided for the ancillary services.

Product			Availability payments	Utilisation payments	Access
FCR	Primary Reaction		Yes	No	common platform weekly
FRR	Regulating Capacity		Yes	€ 70/MWh over day ahead price	Yearly Call for tender + voluntary bids
FRR	Emergency Power		Yes (payment value as bided)	€ 200/MWh or marginal + 10% if higher	Yearly Call for tender
FRR	Reserve Capacity	Balancing	No	€ 200 /MWh over day ahead price	Voluntary bids
		Others; redispatch, not relevant for balancing	No	n/a	Voluntary bids
RR	Replacement Reserves		No	Acc. to the Intraday wholesale market prices	Intraday wholesale market

Table 30: Overview of availability and utilisation payments in the balancing market in the Netherlands

Portfolio management for the BRP is attractive, as it is both well paid and creates lower start-up costs than providing balancing products.

Penalties

Non-availability of contracted Primary Reaction volume is fined with a penalty equivalent to 10 times the bid price[149]. Verification of delivery of balancing energy occurs only for contracted products: Regulating/Reserve Power. Non- or insufficient delivery of contracted products may result in a penalty of 1/6th of the contractual fee, and ultimately in annulling the contract. For Emergency Power the BSP has to supply measurements every 5 minutes to Tennet if the emergency power is deployed. Penalties also occur for non- or suboptimal availability.

149 Tennet et al. (2014): "Potential cross-border balancing cooperation between the Belgian, Dutch and German electricity Transmission System Operators", p.50,available at: http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/Publications/Technical_Publications/balancing/141008_Final_report.pdf (retrieved on 13 March 2015)

Norway

Overview

Norway has extensive hydropower resources. It represents about 95% of its electricity consumption and fills most of its flexibility needs. An important share of residential heating is covered by electricity and electric vehicles are increasing rapidly. Norway has taken important steps in order to allow wider Demand Response participation. Primary Reserve was recently opened to Demand Response and Demand Response and aggregation can now legally bid in all balancing programmes. However, aggregation remains hard to implement and in some case technically unfeasible.

Some barriers hamper the potential of a larger participation of demand-side resources, such as the possibility to participate independently in the market as aggregators. Demand-Side Resources mainly participate through the Regulating Power Market (specific balancing market common to Nordic countries and operated by the power exchange, NordPool Spot) and can participate in the spot market. The minimum bid size represents a barrier for Demand Response and several other technical requirements appear as generation-oriented. Nevertheless, some possible changes are under discussion. Payments are quite attractive, but mainly in the Regulating Power Market.

A. Market overview

The following table shows the electricity market product or sub-products and underlines where Demand Response and aggregated loads can legally participate, including related market sizes.

ENTSO-E's terminology	TSO's terminology		Tot. Capacity / Energy Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Frequency controlled normal operation reserve (FCR-N)		210 MW[150]	✓ Since 9.03.2015	✓
	Frequency controlled disturbance reserve (FCR-D)		353 MW[151]	✓ Since 9.03.2015	✓
FRR-A	Automatic frequency restoration reserve (FRR-A)		300 MW[152]	✓	✓
FRR-M	Fast disturbance reserve (FRR-M)	RKOM week	0-926 MW	✓ up to 683 MW	✓
		RKOM season	749 MW[153]	✓	✓
		Bilateral agreement	136-186 MW[154]	✓ up to 120 W[155]	✓
	Balancing Market (RK)		≈ 2.000 MW[156]	✓ ≈1.000 MW	✓
RR	Strategic reserves		300 MW[157]	✗	✗
	Energy Options (Strategic reserves in consumption)		392 MW	✓	✗

Table 31: List of balancing market products, including volumes and load accessibility in Norway

[150] ENTSO-E (2006): "System operation agreement", art. 4.1.2, available at: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/operations/060613_entsoe_nordic_SystemOperationAgreement_EN.pdf

[151] Ibid., art. 4.1.1

[152] Statnett: "Secundary Reserve", available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/sekundarreserver/ (retrieved on 30th April 2015)

[153] Statnett: "RKOM", available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/RKOM1/RKOM---sesong/ (retrieved on 30th April 2015)

[154] Ibid., where 185.9 MW for the period 11/01/14 to 03/31/15, and 135.9 MW for the period 01/04/14 – 30/04/15

[155] Statnett:"RKOM – Bilateral", available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/RKOM1/Bilaterale-avtaler/ (retrieved on 30th April 2015)

[156] Statnett: "RKOM – RKM", available at: http://www.statnett.no/Demand Responseift-og-marked/Markedsinformasjon/RKOM1/Om-regulerkraft-markedet-RKM/ (retrieved on 30th April 2015)

[157] Statnett: "Reserve Power Plant", available at: http://www.statnett.no/en/Market-and-operations/Reserve-Power-Plants/ (retrieved on 30th April 2015)

B. Markets open to Demand Response

Ancillary Services

Industrial consumers represent a significant level of participation in the balancing market.

- Primary Reserve (FCR-N and FCR-D) recently opened to Demand Response.
- Secondary Reserve (FRR-A) is legally open to Demand Response, but participation is practically unfeasible.
- The Norwegian TSO procures Tertiary Reserve (FRR-M) through seasonal or weekly tenders (RKOM). The TSO also has few bilateral agreements with demand resources that can be activated during the winter period, which require these parties to bid into the Regulating Power Market.
- Approximately half of the capacity involved in the balancing market (RK) comes from load curtailment.
- Energy Options work similarly to the interruptible contracts, giving the TSO the right to request the participants a reduction of their consumption.

In Primary, Secondary and Tertiary Reserves, aggregation is legally possible, but still difficult to implement, and some market developments are required.

Wholesale Market

Flexibility sources have a significant participation in the Spot Market, but it is not possible to know the exact market size. Overall and similarly to the other Nordic markets, a significant share of electricity has been traded in the wholesale market, which represents almost the 100% of the electricity consumption. In the day-ahead Elspot market, between 125 and 142 TWh are yearly traded, while in the intraday Elbas market, around 0,2 TWh are traded.

Capacity market

Norway has not developed a capacity market. A Strategic Reserve mechanism is in place, since 2009, composed by two gas turbines of 150 MW each, owned by the TSO[158] Demand-side resources are not allowed to participate. The strategic reserves are usually activated only between October and March.

C. BRP's agreement prior to load curtailment and other contractual needs

To participate in the balancing market as an independent third-party and sell electricity directly to the TSO, an aggregator would have to register as a BRP and sign agreements with the suppliers/BRPs of the consumers involved in his Demand Response programmes. The absence of standards in such agreements and possible market blockade lead to a situation where such a configuration is not used today in Norway.

As a second option, the aggregator has the possibility to work as a service provider for a BRP. He would then work only within the BRP's perimeter according to their commercial contract.

The regulator and the TSO have not reviewed the rules and responsibilities of the different market actors, and how to better enable competition around

[158] Statnett: "Nyhamna and Tjeldbergodden Reserve power plants", available at: http://www.statnett.no/en/Market-and-operations/Reserve-Power-Plants/ (retrieved on 30th April 2015)

electricity services between aggregators and suppliers. As of today, the BRPs may not wish to contract with the aggregator to avoid complex communication and compensation mechanisms, whereas the aggregator may appear as the supplier's competitor. As the market develops further, it will be necessary to better regulate the mechanisms between suppliers and aggregators limiting risks for market players and providing consumers with open access to the service of their choice.

Aggregators can operate in the day-ahead (Elspot) and intra-day (Elbas) spot markets, by becoming a BRP, or with an agreement with the consumer BRP.

D. Imbalance settlement after load curtailment

As mentioned before, the aggregator operates as a service provider for the consumer's supplier/BRP. Therefore this latter is the only one in direct relationship with the TSO.

The imbalance settlement is common in the Nordic Balance Market, and the imbalances are directly corrected by the TSO that takes into account its reduction order.

Activated reserves (FCR, FRR) are then remunerated in the Regulated Power Market (or RK).

E. BRP-aggregator adjustment mechanism

As mentioned before, in Norway the aggregator operates as a service provider for the consumer's supplier/BRP.

Special agreements between consumer's supplier/BRPs and independent third-party aggregators are theoretically possible, but practically impossible before competition or regulatory requirements force such agreements onto BRPs.

F. Distribution Network

Many pilot projects are on-going at city or local level, such as the demo projects run by The Norwegian Smart Grid Centre[159]; Demo Steinkjer, led by NTE (dynamic tariffs in FP7-project e-GOTHAM and national project DEVID); Smart Energy Hvaler, led by FEAS (contracted capacity tariff tested in national project DEVID); Skarpnes Village, led by AgderEnergi (aggregated households, FP7-project SEMIAH); Statnett pilot North, Demand Response-pilot.

[159] The Norwegian Smart Grid Centre: "Demo Norge", available at: http://smartgrids.no/demo_norge/ (retrieved on 30th April 2015)

Ancillary Services. The delivery time in the balancing market is 15 minutes, which is suitable for Demand Response units. The main remaining barrier in the balancing market is the 10 MW minimum bid size. The minimum limit is high, because this is still a manually operated market (meaning the TSO activates participants by telephone). However, there is an on-going evaluation in regards to bid size and product structure. Regarding the Primary Reserve (FCR-N and FCR-D), and the Secondary Reserve (FRR-A), the TSO can activates multiples of the MW block size (i.e. 5MW, 10MW etc.). On the other side, the Provider may deliver both FRR-A and FCR from the same station, or generator at the same time.

Product	Minimum size (MW)	Notification Time	Activation	Triggered
FCR-N	5	50% in 5s, 100% in 30s	Automatic between 49,9-50,1Hz	Several times per hour
FCR-D	5	50% in 5s, 100% in 30s	Automatic < 49,9Hz	Only in disturbance conditions (≈10.000 min/year)
FRR-A[160]	5	2 min	Automatic out of 49,9-50,1Hz	Max 30min every call
FRR-M (RKOM / bilateral)	10	15 min	Manual	According to the bid / call by the TSO
Balancing Market (RK)	10	15 min	Market based	Several times per day
Strategic reserves	10	4-48 h	energy deficit, depending on the system condition	Few times in winter
Energy Options		7 days	energy deficit (min 2 weeks)	Never activated

Table 32: Description of some main programme requirements in the balancing products accessible to DR in Norway

Wholesale Market

Both day-ahead and intraday markets require a minimum size of 0,1MW to participate.

[160] Statnett (2012): “Technical Product Specification For delivery of FRR-A to Statnett”, Appendix 1 FRR-A, version January 2012, available at: http://www.statnett.no/PageFiles/2581/LFC%20Technical%20Product%20Specification.pdf (retrieved on 30th April 2015)

Prequalification

As the market rules stand today, it is impossible for an aggregator to pool load from different bidding zones. This limits the number and range of consumer sites available. Real time measurement is a barrier to access the Regulated Power Market (RPM), especially for small units. Furthermore, the RPM is still largely based on manual calls (using telephones), which restricts the potential of Demand Response, especially for small loads. On the other side, electronic activation is implemented in Statnett system in 2014 and load suppliers needs to support this functionality.

Anyone taking part in the FRR-A has to be prequalified by the TSO[161].

Baseline methodology

The Norwegian baseline, measurement and verification criteria limit the potential for aggregated loads, and acts as a market barrier to service providers.

A pilot project is currently running among the Nordic TSOs, where FRR-A bid size is reduced to 5MW, and the real time measurement requirements are reduced / removed. The results might influence the market rules for Demand Response[162].

[161] Statnett (2014): "Vilkår - anmelding, håndtering av bud og prissetting i sekundærreservemarkedet til (Term of service, Secondary Reserve)", 8 October 2014, art. 1.2, available at: http://www.statnett.no/Global/Dokumenter/Kraftsystemet/Markedsinformasjon/Frekvensstyrte%20og%20sekund%C3%A6re/FRRAVilk%C3%A5r%20TilH%C3%B8ring%20september2014.pdf (retrieved on 30th April 2015)

[162] Statnett: "Balance Regulation Group - Demand side bidding in Regulation Power Market (RPM)"

Availability/utilisation payments

Payments for Demand Response are attractive only in the balancing market. The level of the penalties for non-performance enables Demand Response participation. The following table contains an overview of the programmes' technical requirements:

Product		Availability payments	Utilisation payments	Access
FCR-N		Yes *n/a*	Marginal cost for zone 42,03 €/MWh (hourly mkt)[163]	Hourly market weekly market
FCR-D		Yes *n/a*	Marginal cost for zone n.a. (hourly market)	Hourly market weekly market
FRR-A		Yes *n/a*	RK	Weekly market
FRR-M	RKOM week	≈0,15-5 €/MWh[164]	RK*	Weekly market
	RKOM season	≈ 0,9 €/MWh[165]	RK*	Yearly tenders
	Bilateral	Yes *n/a*	RK*	Long-term agreements
Balancing Market (RK)		0	Marginal cost for zone 4-150 €/MWh (YTD)	Hourly bids
Strategic reserves		0	0	Owned by the TSO
Energy Options		≈6-7 €/MWh	Pay-as-bid	Yearly tenders

*The utilisation payments from RKOM (options) are gained in the balancing market (RK), since RKOM is options only to secure sufficient volume of bids in RK.

Table 33: Overview of availability and utilisation payments in the balancing market in Norway

163 Statnett: "Balance Regulation Group - Demand side bidding in Regulation Power Market (RPM)"

164 Statnett (2014): Weighted average price 2014 in the hourly market, values available at: http://www.statnett.no/Demand Respon-seift-og-marked/Nedlastingssenter/Last-ned-grunndata/

165 Statnett (2014): RKOM week, available numbers from the 2014 season, values available at: http://www.statnett.no/Drift-og-marked/Marked-sinformasjon/RKOM1/RKOM-uke/

Penalties

The level of the penalties for non-performance would enable Demand Response participation. A short summary is given below for the markets where penalties are described, while the full regulation can be found in the market rules for each market:

- FRR-A, in case of failure of the service: suspension of the player to the market, reduced/cancelled compensations, public blacklisting, decided case by case by the TSO.

- RKOM, in case of not fulfilling RKOM obligations in RK: two levels of penalties, depending on the quality of the resource, 25 x option price for a high quality resource, or 2 x option price in case of a low quality resource, with an upward limitation at total availability payment each week per actor and price zone. The option price is referred to the weighted average volume of the weekly option price, seasonal option price and possible special purchase prices in that period. Risk of suspension, if repeatedly in breaking rules.

- Energy Options: Cancelled compensations, suspension of the participant.

Poland

Overview

Since the latest edition of the report Poland has seen an increase in contracted volume of Demand Response, from approximately 50 to 147 MW. However, Demand Response can only participate in the Emergency Demand Response Programme (EDRP). The balancing market was opened for Demand Response July 1st, 2014, but due to strict requirements and low payments, there were no consumption bids.

In Poland, coal is the predominant source of energy. Aging coal-fired power plants increase costs of generation, while the demand for electricity is expected to continually grow. As power plants are located mostly in the south of the country, the transmission network might face congestions. Thus, DR could add important flexibility resources in areas of the country suffering from transmission and/or generation capacity constraints.

The development of Demand Response in Poland will require legislative changes, as today there is no legal role for the independent aggregator, nor open access to metering data. Another important issue is the question of payments for DR providers. Current regulations provide only for utilisation payments, as there are few calls per year and the payments are low – this constitutes a barrier to the development of Demand Response in Poland.

Main enablers

- There are positive signs from the regulators, e.g. there has been a rapid development of EDRP;
- Balancing market is open to Demand Response.

Main barriers

- Ancillary services are not accessible for Demand Response and not transparently contracted;
- Complex verification and measurement requirements in the balancing market are considered as prohibitive;
- There are no availability payments for the participation in EDRP;
- Lack of legislation concerning demand-side participation hinders development of the market.

1. Market access & aggregation

A. Market overview

The table below gives an overview of the programmes used by the Polish TSO to balance the grid. It can be easily noted that possibilities for Demand Response to participate are limited.

ENTSO-E's terminology	PSE's terminology	Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Reserve (*Regulacja Pierwotna*)	*n/a*	✗	✗
FRR	Secondary Reserve (*Regulacja Wtórna)*	*n/a*	✗	✗
RR	Automatic Voltage Control Reserve (*Automatyczna Regulacja Napięcia i Mocy Biernej*)	*n/a*	✗	✗
-	Emergency Demand Response Programme (*Redukcja Zapotrzebowania na polecenie OSP*)	176 MW[166]	✓	✓
-	Operational Capacity Reserve	4 150 MW[167]	✗	✗
-	Cold Intervention Reserves	830 MW (for 2016-17) [152]	✗	✗
-	Balancing Market	*n/a*	✓	✓

Table 34: List of balancing market products, including volumes and load accessibility in Poland

B. Markets open to Demand Response

Emergency Demand Response Programme (EDRP)

Today, EDSR is the only programme where Demand Response actually participates. The first contract was signed in March 2013 – 30 MW of capacity for summer and 25 MW for winter. By March 2015, there were 5 tenders, with the latest tender round foreseeing a total volume of 200 MW to be contracted (until the expiration of the first volumes contracted).

Ancillary services

Due to the regulatory environment and the lack of transparency, it is not feasible for consumption units to participate in the TSO's system services schemes.

[166] from 1 June 2015

[167] CEPI (June 2015):"Demand Side Management Poland", available at: http://www.cepi.org/system/files/public/documents/events/other/8.%20DSM_Poland_CEPI%20Webinar_AM.pdf (retrieved on 10 June 2015)

Balancing market

The balancing market is a mechanism operated by the TSO, where BRPs can balance their positions "last minute". DR participation was allowed as of July 1st, 2014, but due to the measurement and verification requirements – which closely resemble those required by large generation facilities and are not suited as yet to demand-side resources, no DR provider is participating yet.

The balancing market also includes "Operational capacity reserve". This scheme provides availability payments as an incentive for the generators to be available at peak hours.

"Cold intervention reserve" is another generation-only scheme, providing capacity (and utilisation) payments to maintain the availability of old power plants, already marked for decommissioning[168].

Wholesale market

Demand Response cannot be traded by BRPs on the Polish day ahead and intraday markets. However, the above generation-only capacity schemes, and the coal subsidies have limited price volatility and attractiveness for Demand Response. As an indication of volumes, there is an obligation for the generators to trade at least 15% of produced electricity via the Polish Power Exchange. In 2014, trade on the wholesale market amounted to 119% of domestic production and 111% of domestic demand[169].

Capacity market

The introduction of a capacity market in Poland, is being discussed. The Operational Capacity Reserve, implemented in January 2014 by the TSO, is considered as a temporary solution that could be in use until the eventual establishment of the capacity market.

C. BRP's agreement prior to load curtailment and other contractual needs

In EDRP, aggregation service providers have a bilateral contract with the TSO. They do not require a contract with a BRP.

In order to take part in the balancing market, BSPs must be a BRP and independent aggregation is not possible. As the market currently stands, it is unlikely that a supplier will contract with a consumer outside of its own balancing area.

In order to ease the implementation of such agreements and acquire measurement data from DSOs, TSO updated transmission agreements between TSO and appropriate DSO and BRPs.

D. Imbalance settlement after load curtailment

N/A

E. BRP-aggregator adjustment mechanism

N/A

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[168] PWC and ING Bank (2014): "5 Myths of the Polish Power Industry 2014", p.22, available at: http://www.pwc.pl/en_PL/pl/publikacje/assets/pwc_ing_5_myths_of_the_polish_power_industry_2014_report.pdf (retrieved on 10 June 2015)

[169] Polish Power Exchange ((2014): At the heart of Central European power and gas trading, p. 25, available at: https://www.tge.pl/en/489/polpx-on-the-domestic-and-cee-market (retrieved on 10 June 2015)

F. Distribution network

A project run by PSE and TAURON studied the use of DR measures in network management. There is currently no dedicated arrangement for informing the DSO of a DR event on their network. However as almost all participating consumers are large industrial sites, this is not an issue.

2. Programme requirements

The chart below presents specifications for the programmes where Demand Response is accepted:

Product	Minimum size (MW)	Notification Time	Activation
EDRP	10 MW	6h	Manual
Balancing Market	1 MW	*n/a*	*n/a*

Table 35: Description of some main programme requirements in the balancing products accessible to DR in Poland

EDRP

The specifications of the latest tender provide for 24 month contracts (winter or summer seasons). The maximum number of activations during this period is 15, and there can be a maximum of 1 per day and 3 per week. One "testing" activation is guaranteed otherwise activations are not guaranteed. Each reduction can be 2, 3 or 4 hours long. The minimum bid size is 10 MW, and aggregation of individual units is allowed. The consumption units have to be equipped with at least hourly meters.

Balancing markets

The minimum bid in the balancing market is 1 MW.

Wholesale market

Demand Response cannot participate in the Polish day ahead and intraday markets.

3. Measurement & verification

Prequalification

EDRP. Measurement and verification take place at an aggregated level.

Balancing market. The pool of loads has to prequalify as an aggregate. There is no minimum size for an individual unit within the pool, but there are high requirements in terms of measurement and planning accuracy, as Demand Response providers shall use the same baseline calculation methodology as generators. If these technical requirements are not fulfilled, the participation is suspended.

Baseline methodology

EDRP

provides for two methods of calculating the baseline based on:

- consumption forecast if participant meets accuracy requirements or
- consumption in the last hour before the demand reduction command was issued (3 hours or more before actual reduction).

Balancing market

DR providers shall use their hourly consumption forecasts. In order to qualify for participation, the forecasting accuracy may not exceed 5% for each 3 consecutive hours (including off-peak hours) which may appear as inadequate for consumption units.

4. Finance & penalties

Availability/utilisation payments

The table below presents payments available in the aforementioned services and programmes, accessible for Demand Response:

Product	Availability payments	Utilisation payments	Access
EDRP	No	220-276 €/MWh (depending on accepted offers)	Tenders
Balancing market	No	30-50 €/MWh	Bids

Table 36: Overview of availability and utilisation payments in the balancing market in Poland

EDRP and the balancing market programmes provide no availability payments and – for this reason – quite high utilisation payments. Bids accepted in the latest tender round ranged from 950 PLN to 1 199 PLN/MWh (220-276€). However, only 4 hours call per 2 years are guaranteed and were executed so far – this is insufficient to support market growth and do not reflect the payments available to generation assets.

Market players advocate for the introduction of availability payments similar to the payments for the Operational Capacity Reserve or cold reserves (mentioned above). These payments currently amount to:

- 140k PLN/MW/year (34k€/MW/year) for Operational Capacity Reserve and
- 210-240k PLN/MWh / year (51-58 kEUR/MW/year) for Cold Intervention Reserve.

Penalties

In EDRP penalties seem reasonably proportioned.

In balancing market, prices are considered to be low. In 2014 they varied from approximately 70 to 1 470 PLN/MWh (17-360 €/MWh). However the prices above 800 PLN/MWh (195 €/MWh) occurs very rarely, except toward the end of the year, when Operational Capacity Reserve payment for generators were temporary not in place.

Slovenia

Overview

The Slovenian balancing market opened to Demand Response in 2014. However, an aggregated form of Demand Response is allowed only within the Tertiary Reserve. First tenders for the aggregated Demand Response were organised by ELES, the Slovenian TSO, in 2014. The contracted volume in 2014 was 12 MW, and 20 MW in 2015.

The most significant barrier to enter the market is the limited number of accessible programmes and small volumes. According to ELES, there is a need for improvements as far as the quality of Demand Response is concerned, on both the TSO's and Demand Response providers' side, so that it can compete with conventional generation units.

There are plans to accept aggregated load in the Secondary Reserve service, starting probably in 2016.

Main enablers

- Requirements for the participation in Tertiary Reserve (apart from the requirement of 24/7 availability) are appropriate for DR capabilities;
- TSO provides both utilisation and availability payments for the participation in the Tertiary Reserve.

Main barriers

- Primary and Secondary reserve are not accessible for aggregated load;
- There is a requirement of 24/7 availability in order to participate in the Tertiary Reserve;
- Wholesale market is closed to Demand Response participation;
- Due to the small size of the Slovenian market, business opportunities are rather limited.

A. Market overview

As the table below shows, Demand Response participation in Slovenia is possible in every reserve, however aggregated load is accepted only in the Tertiary Reserve:

ENTSO-E's terminology	TSO's terminology	Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primary Reserve	n/a	✔	✘
FRR	Secondary Reserve	n/a	✔	✘
FRR	Tertiary Reserve	348 MW	✔	✔ (20 MW)

Table 37: List of balancing market products, including volumes and load accessibility in Slovenia

B. Markets open to Demand Response

Balancing market and ancillary services

Only the Tertiary Reserve service is open to aggregated Demand Response. Participation in the Primary and Secondary Reserves is limited to bilateral contracts between TSO and big industrial consumers, such as paper mills.

Aggregation is allowed in the Tertiary Reserve. The only entity that currently operates as a form of an aggregator is the Virtual Power Plant, that is managed by the supplier Elektro Energija and the DSO Elektro Ljubljana, with CyberGrid as the system provider.

Wholesale

There is no Demand Response traded on the wholesale market.

Capacity market

For the time being, there are no plans to introduce a capacity market in Slovenia.

C. BRP's agreement prior to load curtailment and other contractual needs

There are no clear rules concerning this question. In general, a party interested in providing Demand Response services is required to obtain the consent of the BRP, but in some cases (to certain extent) the use of demand-side flexibility is tolerated without written agreement. Apart from that, the aggregator needs to have a contract with the pro/consumers (flexibility providers), and a market entity (where he will place this flexibility).

D. Imbalance settlement after load curtailment

There is no official mechanism for correcting BRP´s imbalance caused by Demand Response events.

E. BRP-aggregator adjustment mechanism

There is no official compensation mechanism for supplier's revenue losses resulted by a third party.

F. Distribution network

For the moment, there are no programmes aimed at the network management.

2. Programme requirements

Balancing Market and ancillary services

There are annual tenders organised by ELES. Demand Response provider shall ensure 24/7 availability which can be difficult for many consumers to fulfil and shrinks the possible pool of load. The response time is 15 minutes, and it must be possible to deliver the service for a maximum 2 hours. The time between two activations must be at least 10h, with a maximum number of 2 activations per day. The minimum aggregated bid size is 5 MW.

The following table summarises the requirements:

Product	Minimum size (MW)	Notification Time	Activation	Triggered
Tertiary Reserve	5 MW	15 min	manual	≈35 times in 2014

Table 38: Description of some main programme requirements in the balancing products accessible to DR in Slovenia

Wholesale Market

Demand Response cannot access the wholesale market.

Capacity market

There is no capacity market in Slovenia.

3. Measurement & verification

Prequalification

All potential Demand Response providers have to go through a thorough pre-qualification process. Having prequalification (EVORP) documents properly submitted, the TSO will carry out tests for each unit 7 days in a row, with a maximum of 10 hours of activation total. In addition to other requirements mentioned in Section 2, each Demand Response unit has to support real-time bi-directional communication with the national control centre.

Moreover, several legal and formal conditions have to be fulfilled (i.e. proper individual connection agreements, consensus of all members of the virtual power plant to participate at ancillary services, etc.). An aggregator must also submit a guarantee of 15.000 EUR/MW

Baseline methodology

There is one officially used baseline (Baseline 1). It is based on Demand Response unit schedule, where actual reduction is determined as the deviation of 'reduced' consumption from the scheduled 'regular' consumption. The companies can use their own baselines if they are accepted by the TSO.

As far as Virtual Power Plant (VPP) is concerned, baseline is defined by the schedule provided by the VPP. In order to match schedules with the actual consumption, they are proportionally scaled to the last measured value before the activation.

4. Finance & penalties

Availability/utilisation payments

As tenders are organised only for the participation in the Tertiary Reserve, the chart below presents payments only for that service:

Product	Availability payments	Utilisation payments	Access
Tertiary Reserve	38 000 EUR/MW	240 EUR/MWh	tender

Table 39: Overview of availability and utilisation payments in the balancing market in Slovenia

Penalties

There are rather high penalties for non-availability. There is a 20% tolerance concerning under- and over-delivery.

Guarantee: An aggregator must submit a guarantee of 15.000 €/MW.

Spain

Overview

Today, Spain relies mostly on hydro and gas for its flexibility needs. As Spain is evolving towards more distributed energy generation, the need for flexibility is expected to increase in the coming years. Despite the fact that there are certain smart grid pilot projects under development in Spain, the development of Explicit Demand Response is limited.

Aggregation is not legal in the Spanish electricity system and there is only one scheme allowing Explicit Demand Response: the Interruptible Load programme. The scheme, which is reserved only for large consumers, is managed by the TSO, Red Eléctrica de España. The programme acts as an emergency action, in case the system is lacking generation and the balance resources are not enough. Though annual tests are conducted, this programme has not been called for consecutive years, raising questions whether it is a genuine interruptible load programme or a form of subsidy to the national industry. Proposals to open balancing services to Demand Response could lead to changes in 2016-2018, especially given that a full smart meter roll-out is expected by 2018.

1. Consumer access & aggregation

A. Market overview

The following table presents the electricity market product or sub-products and underlines where Demand Response and aggregation could participate, including related market sizes.

<table>
<tr><th>ENTSO-E's terminology</th><th colspan="2">TSO's terminology</th><th>Tot. Capacity Contracted[170]</th><th>Load Access & Participation</th><th>Aggregated Load Accepted</th></tr>
<tr><td>FCR</td><td colspan="2">Primary Control</td><td>n/a</td><td>✗</td><td>✗</td></tr>
<tr><td>FRR</td><td colspan="2">Secondary Control</td><td>2.876 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td>RR</td><td colspan="2">Tertiary Control</td><td>5.142 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td>RR</td><td colspan="2">Deviation Management</td><td>3.252 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td></td><td colspan="2">Guarantee of Supply Constraints</td><td>4.085 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td></td><td colspan="2">Technical Constraints (PDBF)</td><td>7.433 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td></td><td colspan="2">Real-Time Constraints</td><td>2.258 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td>RR</td><td colspan="2">PowerReserve</td><td>3.010 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td></td><td colspan="2">Secondary Regulation Band</td><td>1.203 GWh</td><td>✗</td><td>✗</td></tr>
<tr><td rowspan="3"></td><td rowspan="2">Interruptible Mainland[171]</td><td>5MW blocks</td><td>1.190 MW</td><td>✓ 1.190 MW</td><td>✗</td></tr>
<tr><td>90MW blocks</td><td>810 MW</td><td>✓ 810 MW</td><td>✗</td></tr>
<tr><td colspan="2">Interruptible Islands</td><td>≈50 MW</td><td>✓ ≈50 MW</td><td>✗</td></tr>
<tr><td></td><td colspan="2">Capacity Market</td><td>≈2.500 MW</td><td>✓</td><td>✗</td></tr>
</table>

Table 40: List of balancing market products, including volumes and load accessibility in Spain

B. Markets open to Demand Response

Balancing market & Ancillary Services

Currently, Demand Response does not have access neither to balancing market nor to the ancillary services.

Interruptible Contracts

The programme does not allow aggregation and is limited to large industrial consumers, connected to the HV grid. It represents an available capacity of 2.000 MW of demand reduction in peak hours. Industrial energy consumers involved in this scheme are construction industries (steel, concrete, glass, etc.), or other material factories (paper, chemistry, etc.) and desalinisation plants (in the Canarias Islands). From 2015, a new framework applies for the programme in the mainland Spain, while the previous rules still apply in the insular Spain[172]. In mainland Spain, 113 consumers were awarded in the tender round for 2015, with 139 connection points[173], while, in insular Spain, 15 consumers were awarded in the tender round for 2014.

Wholesale market

Only generators, with a production unit of at least 50 MW, can participate as seller in the wholesale market. Flexibility resources can participate in the spot market, though demand bids with indication of price. The role of aggregator is already mentioned (as "gestor de carga", as better explained below), but only on the consumption side[174]. Regarding the total market size, in 2014, around 140TWh were traded in the day-ahead market, and around 22TWh[175] in the intraday market. Excluding the bilateral contracts, 82% of the total

[170] Red Electrica (2013): "The Spanish Electricity System", available at: http://www.ree.es/en/publications/spanish-electrical-system/spanish-electricity-system-2013 and Red Electrica (2013): "Servicios de ajuste de la operacion del sistema, avance 2013", available at: http://www.ree.es/es/publicaciones/2014/02/servicios-de-ajuste-de-la-operacion-del-sistema-avance-2013

[171] BOE-A-2014-10399, Spanish Official Gazette (2014): "Resolución de 10 de octubre de 2014", published on 14 october 2014, art.5, (mainland Spain), and Red Electrica (2013), 'The Spanish Electricity System', Ibid. (insular Spain)

[172] BOE-A-2013-11461 (2013): "Orden IET/2013/2013, 31 October 2013", published on 1 november 2013, modified on 11 march 2014

[173] Red Electrica (2014): "Informacion Subastas TE2015", 2015 tender

electricity consumption was exchanged on the OMIE platform, including both Iberian markets (Spain and Portugal).

Capacity market

The capacity mechanism allows for the participation of generation units only, providing both availability and utilisation payments[176]. From 2013, the availability payment has been reduced, and the programme duration extended[177].

Overall, there is no possibility for aggregated demand-side resources to take part in the Spanish electricity market. There are no standards at the moment defining their relationship with the BRP and the TSO.

C. BRP's agreement prior to load curtailment and other contractual needs

Such an agreement is not applicable, since, as mentioned above, Demand Response does not have access to the balancing markets and aggregation is illegal.

D. Imbalance settlement after load curtailment

Participants in the interruptible load programme are directly in contact with the TSO via their ICT system. The supplier's imbalance is directly corrected by the TSO, which takes into account its reduction order, although as the programme has not been activated within the last decade, this provision is symbolic.

E. BRP-aggregator adjustment mechanism

Such an agreement is not applicable, since, as mentioned above, Demand Response does not have access to the balancing markets and aggregation is illegal.

F. Distribution network

In the Interruptible Contracts, DSOs have the possibility to request from the TSO to call an interruption if needed[179]. Furthermore, at DSO level, some pilot projects are on-going at city level, such as "Smart City Project" in Malaga, and the "Barcelona Smart City"[178].

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174 BOE-A-2014-916 (2014): "Resolution of 27 January 2014", published on 30 January 2014

175 OMIE (2014): Values calculated on monthly reports, 2014, available at: http://www.omel.es/en/home/publications

176 BOE-A-2011-18064 (2011): "Orden ITC/3127/2011, 17 November 2011", published on 18 November 2011

177 BOE-A-2013-7705 (2013): "Real Decreto-ley 9/2013, 12 July 2013", published on 13 July 2013

178 Smart city Malaga (2015), available at: http://www.smartcitymalaga.es/ (retrieved on 30th April 2015) and Barcelona Smart City (2015), available at: http://smartcity.bcn.cat/en (retrieved on 30th April 2015)

2. Programme requirements

Product		Minimum size	Notification Time	Activation	Triggered
Interruptible Contract (Mainland)	5MW blocks	Blocks of 5 MW	three options: (1) Instantly execution, no notification, (2) Fast execution, 15min, (3) Hourly execution, 2h[179].	Automatic	Max 240 h/ year and 40/h month
	90MW blocks	Blocks of 90 MW		Automatic	Max 360 h/ year and 60 h/ month
Interruptible Contract (Islands)		0,8 MW	Five options, from 2 hours to instantly	Automatic	Max 120 h/year

Table 41: Description of some main programme requirements in the balancing products accessible to DR in Spain

Interruptible Load Programme

The interruptible load programme is the only Demand Response programme available and, as mentioned above, it does not allow aggregated demand-side resources to participate[180]. In mainland Spain, the scheme was introduced in 2008, with a threshold of 5MW to participate. From 2014, different conditions were introduced for interruptible loads bigger than 90MW[181]. From 2015, it is possible to bid with blocks of curtailable load: 5MW blocks, or 90MW blocks. For the 5MW-block product, it is required to have a minimum consumption of the assigned resource (i.e. 5MW for one 5MW block), while for the 90M-blocks product it is required to have at least the 91% of the assigned resource (i.e. 81MW for one 90MW block)[182]. In insular Spain, Canaries and Baleares, the old framework still applies, with a minimum size of 0,8MW to participate.

3. Measurement & verification

Note: This section is applicable only for the case of the Interruptible Load Programme, as Explicit Demand Response cannot participate in any other market programme.

Prequalification

In the Interruptible Load Programme, participants must have in an ICT system, which links them directly to the TSO, and not to the DSO where they may be connected. If they are connected to the DSO's network, the DSO does not participate in it, and it is not even able to forecast it in advance. The supplier's imbalance is directly corrected by the TSO, which takes into account its reduction order.

[179] BOE-A-2013-11461 (2013), Ibid., art. 5
[180] BOE-A-2007-14798 (2007): "Orden ITC/2370/2007, 26 July 2007", published on 3 August 2007
[181] BOE-A 2012-15706 (2012): "Orden IET/2804/2012, 27 December 2012", published on 29 December 2012
[182] BOE-A-2013-11461 (2013), Ibid., art. 9

Baseline methodology

In the Interruptible Load Programme, the baseline is set individually; the available capacity is tested around twice a year. The participants have to send monthly the forecast to the TSO, for the coming two months. In the absence of aggregated Demand Response, there is no regulation concerning single unit requirement or baseline definitions for aggregated loads.

4. Finance & penalties

Note: This section is applicable only for the limited case of Interruptible Load Programme, as Demand Response cannot participate in any other market programme.

Availability/utilisation payments

Product		Availability payments[183]	Utilisation payments	Access
Interruptible contracts, Mainland	5MW blocks	96.654 €/MW (2015)(260.000 €/MW maximum)	Balancing market, tertiary reserve	tender-based
	90MW blocks	176.339 €/MW (2015)(350.000 €/MW maximum)	Balancing market, tertiary reserve	tender-based
Interruptible contracts, Islands		n/a	n/a	tender-based

Table 42: Overview of availability and utilisation payments in the balancing market in Spain

Interruptible Load Programme

The new framework for Interruptible Contracts, in mainland Spain, aims to achieve budget savings, by the introduction of an auction mechanism, with a tender-based price for the availability remuneration. The total availability payments for 2015 decreased to about € 350 million, representing about € 200 million less than the total expenses in 2014.

In Spain, the old framework still applies with an availability payment only, limited to €20/MWh consumed. Payments are higher if the energy is consumed in off-peak hours.

From 2015, fees applicable to intermittent generators plants, as well as from retail consumers, will fund the availability payments. The utilisation payment is sourced according to the balancing market rules.

[183] Red Electrica (2015): "InformacionSubastas TE2015", Ibid.

Penalties

Interruptible Load Programme

For the Interruptible Contracts in mainland Spain, the new scheme has defined stricter conditions in case of non-fulfilment of the project requirements. A penalty of up to 120% of the availability price applies for the first failure and exclusion from the tender applies for a second failure[184].

For insular Spain, the previous conditions still apply, with penalty of up to 100% of the availability price, even in case of two failures in the same year.

[184] BOE-A-2013-11461 (2014), Ibid., art. 11

Sweden

Overview

Flexibility comes mainly from hydropower plants in the north of Sweden (SE1 and SE2), while thermal plants are sometimes activated in the south of Sweden, in case of congestions or in case of peak demand. Demand Response participation and aggregation of demand-side resources are legally possible in Sweden. However, wider Demand Response participation could be triggered with the definition of appropriate roles and responsibilities between players, which would allow for consumers to freely choose their Demand Response service provider, while protecting all market participants.

Primary, Secondary and Tertiary Reserves are legally open to demand-side resources and including in an aggregated manner. The participation is still limited and some regulatory changes are needed to fit better demand-side resource characteristics. Demand-side resources mostly participated in the Strategic Reserve and in the Regulating Power Market (RPM), specific balancing market operating by the power exchange Nord Pool Spot. As in other Nordic markets, an independent third-party aggregator needs to be a BRP, and obtain a contractual agreement from consumers' supplier/BRP. This bilateral relationship between competitors hamper the market potential of demand-side resources.

Product requirements also limit the possibility for Demand Response to participate. In the Secondary, Tertiary Reserve and the RPM, the minimum bid size represents a significant barrier for wide participation. The level of payments and penalties to provide ancillary services is not public. Demand-side resources also participates in the spot market, but it is not possible to have a clear market size.

A. Market overview

The following table shows the electricity market product or sub-products and underlines where Demand Response and aggregated loads can participate, including related market sizes.

ENTSO-E's terminology	SVK's terminology	Market size	Load Access & Participation (MW)	Aggregated Load Accepted
FCR	Frequency Containment Reserves for normal operating band (FCR-N)	230 MW[185]	✔ ≈0	✔
	Frequency Containment Reserves for disturbances (FCR-D)	412 MW[186]	✔ ≈0	✔
FRR-A	Automatic Frequency Restoration Reserves (FRR-A)	still limited	✔ ≈0	✔
FRR-M	Fast disturbance reserve (FRR-M)	1.290 MW[187]	✔ ≈10 MW	✔
RR	Strategic Reserve / Peak Power Reserve[188]	1.500 MW	✔ 626 MW	✔
	Balancing Market (RPM)	1,6 TWh[189]	✔	✔

Table 43: List of balancing market products, including volumes and load accessibility in Sweden

In addition to the listed programmes, "Slow Active Disturbance Reserve" and "Reactive Reserve" are available. These schemes are rarely used and remain closed to Demand Response. The first programme is for power station with a ramp up time higher than 15 min, but the TSO only exceptionally call them, because it satisfies its needs with faster stations. There are not any precise statistics about the latter programme.

B. Markets open to Demand Response

Ancillary Services

Although aggregation of load curtailment is legal within the ancillary services in Sweden. Demand Response mainly participates in the Regulating Power Market (RPM), which is a specific balancing market operated by the power exchange, Nord Pool Spot.

Wholesale Market

Demand-side resources represent a significant share in the Nord Pool Spot Market, day-ahead (Elspot) and intraday (Elbas). However, it is still not possible to have a clear picture about the size of the Demand Response's participation in the market. In case demand-

[185] ENSTO-E (2006): "System Operation Agreement" Ibid. par. 4.1.1
[186] ENSTO-E (2006): "System Operation Agreement" Ibid., par. 4.1.2
[187] ENSTO-E (2006): "System Operation Agreement" Ibid., par. 4.2
[188] Elforsk (2014): "Rapport 14:29, Demand Response in the strategic reserve, The Case of Sweden", p. 31, resources for the year 2014/2015, available at: www.elforsk.se/Documents/Market%20Design/projects/ER_14_29.pdf
[189] NordPool Spot (2014), RPM 2014 value, available at: http://www.nordpoolspot.com/Market-data1/Regulating-Power1/Regulating-Power--Area1/NO11/Norway/?view=table (retrieved on 30th April 2015)

side resources participate in the spot market, they are unavailable for the Peak Load Reserve (SR). Overall and similarly to the other Nordic markets, a significant share of electricity is traded in the wholesale market. In 2013, more than 90% of the total electricity consumption was traded, 130 TWh in the day-ahead market (Elspot), and 1,5 TWh[190] in the intraday market (Elbas).

Capacity market

Sweden has no capacity market mechanism. A Strategic Reserve exists, where Demand Response can participate. The TSO can contract the necessary amount, with a cap defined by the regulation. The cap is set to be gradually reduced in the period 2011-2020, from 2000 MW to 750 MW. The share of Demand Response was initially planned to increase up to 100%[191], and then softened to be at least the 25% of the contracted capacity[192].

C. BRP's agreement prior to load curtailment and other contractual needs

To operate in the electricity markets, an independent third-party aggregator would have to register as a BRP and to sign an agreement with the consumer's supplier/ BRP.

Registering as a BRP requires annual fee of about 2500 €/year, and the installation of an electronic reporting system connected to the exchange platform Ediel (or signing a contract with an agent that has such equipment).

Moreover, the relationship between the supplier and the aggregator can act as a market entry barrier as the consumer's supplier/BRP is unlikely to wish to cooperate with a potential competitor. In the Strategic Reserve, much of the responsibilities lies on the resource owner. The roles and responsibilities of market actors require further definition, in order to enable consumers to freely choose their service provider and limit risks for all parties.

D. Imbalance settlement after load curtailment

The BRP's imbalances are directly corrected by the TSO which takes into account its reduction order.

E. BRP-aggregator adjustment mechanism

There is not specific regulation to compensate the electricity bought in advance by the BRP and not consumed because of a load curtailment.

Special agreements between consumer's supplier/ BRPs and independent third-party aggregators are theoretically possible, but practically impossible before competition or regulatory requirements force such agreements onto BRPs. This issue should be resolved in order to clarify roles and responsibilities between the BRP, aggregator and supplier and to provide consumers a clear path to market.

190 NordPool Spot, respectively 2014 and 2013 values

191 Svenskförfattningssamling 2003:436 and 2010:2004 (Laws 436/2003 and 2004/2010): "Constitution of Strategic Reserve, and Ministry of Enterprise, Energy and Communications Sweden (2012): "Experiences with the implementation of the strategic reserve in Sweden"

192 Svenskförfattningssamling 2014:213 (Law 213/2014)

F. Distribution network

Small electricity consumers are billed by suppliers and by the DSOs according to their electricity subscription and use. About 170 DSOs operate in Sweden, focused on different geographical areas. Different network tariffs are in place for off-peak and peak hours, to penalize with higher rates consumption in peak hours, which are considered day hours in the winter period.

Referring to direct involvement in projects, some pilots are in place, like Smart Grid Gotland[193], that is planned to be completed in December 2015 in Gotland Island, and includes Demand Response programmes. Some other smaller projects are also on going.

2. Programme requirements

Ancillary Services. With the current structure, Demand Response cannot cope with the product requirements for Primary (FCR-N, FCR-D) and Secondary (FRR-A) Reserves. Demand Response could participate with provisions that would make these Reserves more technically accessible (e.g. activation only for deviations above 100 mHz – which leads to limited times of activation, and thus to less impact in the industrial/commercial/domestic processes). In regard to the Tertiary Reserve (FRR-M), the main barrier is the high minimum bid[194]. The following table contains an overview of the programmes' technical requirements:

Product		Minimum size (MW)	Notification Time[195]	Activation	Triggered
FCR	FCR-N	0,1	63% in 60s, 100% in 3 min	Automatic with frequency is out of 49,9-50,1Hz	Constantly
	FCR-D	1	50% in 5s, 100% in 30s	Automatic with frequency under 49,9Hz	Approx. 500 times/year
FRR-A		5	2 min	Automatic	Constantly
FRR-M		10 (SE1,SE2,SE3), 5 (SE4)	15 min	Manual by a phone call	Before 2014, every hour
Slow active disturbance reserve		n/a	15 min	Manually	n/a
Reactive reserve		n/a	n/a	n/a	n/a
Strategic reserves		5	15 min	Manually	Historically less than 10h/year
Balancing Market		10	15 min	Market based	Market based

Table 44: Description of some main programme requirements in the balancing products accessible to DR in Sweden

[193] Smart Grid Gotland (2015), www.smartgridgotland.com (retrieved on 30th April 2015)

[194] Since 1st November 2011, the Swedish electricity market has been divided into four distinct price areas (i.e. S1, S2, S3, S4).

[195] SVK (2014): "Balance Responsibility Agreement", available at: http://www.svk.se/siteassets/aktorsportalen/elmarknaden/balansansvar/dokument/brp-agreement-20150201.pdf (retrieved on 30th April 2015)

Wholesale Market

The 0,1 MW minimum bid size for the day-ahead and intraday markets enables demand-side participation.

3. Measurement & verification

Prequalification

The balancing markets do not have a well-defined and standardized system for measurement and verification. Verification will be a problem if Demand Response increases rapidly. However, with the market's current low volumes, it can be managed manually. Measurement and verification for aggregated Demand Response will need further definition in order to ensure Demand Response delivers a reliable resource. FCR programmes require a frequency measurement device installed at the location of the entity, with a certain level of accuracy.

Prequalification is required for FRR-A. For FRR-M, the facilities have to be qualified as "Regulation Object" by the TSO.

Baseline methodology

There is no publicly available baseline methodology.

4. Finance & penalties

Availability/utilisation payments

The Swedish Ancillary Services are dominated by hydropower, due to the fact that it is a cost efficient and rapidly adjustable resource. However, Demand Response's participation is expected to grow, following the increasing share of intermittent generation into the network. Svenska Kraftnät, the TSO, is examining whether there is potential to use Demand Response for disturbance reserve in the future, possibly in combination with wind. Payments and penalties related to participation in the ancillary services are not public. The following table summarises the main participation conditions in the different programmes:

Product		Availability payments	Utilisation payments	Access
FCR	FCR-N	Yes (not public)	Yes (not public)	Daily
	FCR-D	Yes (not public)	Yes (not public)	Daily
FRR-A		Yes (not public)	Yes (not public)	Weekly
FRR-M		0	Yes (according to NordPool Spot bids)	Hourly
Strategic Reserve		Yes (not public)	Regulating bid	Tender, yearly procurement

Table 45: Overview of availability and utilisation payments in the balancing market in Sweden

Penalties

References to penalties are stated in the BRP agreement, with the possibility for the TSO to ask an ad hoc amount caused for instance by systematically large imbalances[196].

[196] Ibid. par.8, 9

Switzerland

Overview

After certain regulatory changes, which took place in 2013, Switzerland has become a European frontrunner when it comes to aggregated Demand Response. Technical barriers have been removed and, above all, Swissgrid allows BSPs to aggregate loads from anywhere in the country without the agreement of the customers' BRPs, setting imbalances directly with them. This regulation provides clear roles and responsibility for the BRP and BSP, while mitigating the costs and risks of both parties. It also establishes a critical set of processes under the TSO's supervision and could provide a model for the rest of Europe.

Some critical barriers still exist in the balancing market, where symmetric bids and proportional dispatching (instead of following a merit order list) are required in the Secondary Control Reserve.

Due to spring critical water scarcity, Demand Response might be an important source of flexibility in the future in order to compensate for a lowered level of hydropower. The phasing out of Swiss nuclear plants – planned for 2034 – will bring more intermittent energy in the Swiss electricity system. This may increase the need for Demand Response provision in ancillary service programmes.

In 2014, Switzerland has seen a slight uptake in number of Demand Response providers while interruptible load contracts for large consumers do still not exist.

1. Consumer access & aggregation

A. Market overview

All Swiss balancing market programmes are open to Demand Response and aggregation is allowed. A small number of third-party aggregators have started to offer Demand Response in the balancing market. Information on the exact account of demand-side loads in the various programmes is not available.

ENTSO-E's terminology	Swissgrid's terminology		Tot. Capacity Contracted	Load Access & Participation	Aggregated Load Accepted
FCR	Primärregelleistung		71 MW	✔ (? MW)	✔
FRR	Sekundärregelleistung[197]		390.85 MW	✔ (? MW)	✔
RR	Tertiärregelleistung[198]	Weekly +	157.04 MW	✔ (? MW)	✔
		Weekly –	124.34 MW	✔ (? MW)	✔
		Daily +	255.82 MW	✔ (? MW)	✔
		Daily –	144.35 MW	✔ (? MW)	✔

Table 46: List of balancing market products, including volumes and load accessibility in Switzerland

B. Markets open to Demand Response

Balancing Market

As a result of the regulatory developments which took place early in 2013 and a transitional period from May to October 2013, Demand Response and aggregation have access to most of Swiss ancillary services: including Primary, Secondary and Tertiary Control Power (positive and negative). Main regulatory barriers have been removed and aggregators can bid into these programmes.

Interruptible Contracts

Contracts for interruptible loads do not exist in Switzerland.

Capacity market

A capacity market for Switzerland alone is not being considered, as it would bring high administrative costs, inadequate liquidity and insufficient competition between individual power generators. Alternatively Switzerland will continue to work more closely with its neighbours.

Wholesale Market

Currently there is no Demand Response participation on the EPEX spot market from Switzerland, although in principle Virtual Power Plants (VPP), including demand-side flexibility, could already participate in the day-ahead market. The contractual situation to enable the offering of independently aggregated demand-side flexibility on the day-ahead market has yet to be regulated. The total Swiss power being traded on the EPEX day ahead market increased in 2014 by 9% to a new record high of 20'466'889 MWh. The intraday market volume, with 2014 being the first full year of 15-minute trading contracts, saw a massive increase by 230% to 1'093'188 MWh, also an all-time high[199].

[197] Swissgrid (2015a): Weekly average of accepted volumes in 2014, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/secondary-control-power.html (retrieved on 30th March 2015)

[198] Swissgrid (2015b): Hourly average of accepted volumes in 2014, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/tertiary-control-power.html (retrieved on 30th March 2015)

[199] EPEX (2015): Press release, available at: https://www.epexspot.com/document/30189/2015-01-13_EPEX%20SPOT_2014_Annual%20Press%20Release+.pdf (retrieved on 25th April 2015)

C. BRP's agreement prior to load curtailment and other contractual needs

In the balancing markets, the aggregator (BSP) does not have any contracts with the Balance Responsible Parties of the areas where it operates. The BSP contracts directly with Swissgrid (the Swiss TSO) to access the market. BSPs can aggregate load from anywhere in the country. Neither the BRP nor the BSP are charged for the imbalance caused by the load curtailment. Swissgrid corrects each BRP's balance group the day after the operation, taking into account all the operations that took place in its respective area.

Similar rules are not yet in place for demand-side offers into the wholesale market.

D. Imbalance settlement after load curtailment

In the balancing market, Swissgrid corrects each BRP's balance group the day after the operation, taking into account all the operations that took place in its respective area.

E. BRP-aggregator adjustment mechanism

According to the framework agreement on aggregated loads, the added value, caused by the provision of balancing services, is handed to the aggregator. However, the aggregator is obliged to compensate the BRP for the difference in consumed energy with a payment that is determined by the quarter-hourly day-ahead spot price of the Swiss Electricity Index (SwissIX). This regulatory structure and clarity will be critical for the long-term stability and growth of Demand Response in Europe. However it should be noted that if the spot price is used for payment this will block Demand Response from participating in the spot market now and in future. The use of this price rather than a more complex but accurate sourcing price is questionable.

F. Distribution network

Currently there are only pilot programmes on the DSO level.

Balancing Market and ancillary services

Primary control power (Primärregelleistung).

Primary control power is being procured by means of various weekly tenders. 46 MW are procured through an invitation to tender issued by Swissgrid, and a further 25 MW can be provided from France or Austria. The remaining share is procured in a joint tender together with the German transmission system operators.

Secondary control power

(Sekundärregelleistung). Around 400MW of secondary control is being tendered for every week, with minimum bids of 5MW. Secondary control power is dispatched "proportionally", not through a merit order list. This means that for every TSO dispatch of secondary control power, every BSP has to respond, according to its overall proportion of the market. As opposed to a merit order dispatch, where offers are dispatched consecutively according to their price, the proportional system dispatches **all** BSPs every time secondary control is needed. This blocks industrial and a large share of commercial customers from participating in this market. Also, only symmetric bids are accepted, and only the capacity price is opened for bidding, while the energy price is being based on the SwissIX hourly price. The symmetric bidding requirement remains a barrier to consumer participation and consumption patterns and adjustments is rarely symmetric.

Tertiary control power (Tertiärregelleistung)

Tertiary control can be tendered for asymmetrically, with minimum bids of 5MW and a total volume of 100MW. There are either 6 blocks of 4 hours opened every day or weekly tenders (00:00 Monday – 24:00 Sunday). The blocks of tenders and the asymmetrical bidding requirement both support the participation of consumers through providing the required flexibility in timing and up or down bids.

Product[200]	Minimum size (MW)	Notification Time	Activation	Triggered
Primärregelleistung	1 MW	30 sec	Automatic	Up to several times per day
Sekundärregelleistung	5 MW	5 min	Remote-controlled	Up to several times per day
Tertiärregelleistung	5 MW	15 min	Manual (Email/phone)	Up to several times per day

Table 47: Description of some main programme requirements in the balancing products accessible to DR in Switzerland

Enablers

Aggregation was illegal prior to April 2013, but a regulatory process has taken place after this date to remove all the technical barriers within ancillary services, which were preventing aggregators from entering these programmes. For example, the minimum bid size does not exceed 5MW[201].

200 Swissgrid (2015c): "Basic principles of ancillary service products", available at: http://www.swissgrid.ch/dam/swissgrid/experts/ancillary_services/Dokumente/D150401_AS-Products_V9R0_EN.pdf (retrieved on 4th April 2015)

201 ibid. (retrieved on 4th April 2015)

Barriers

Whereas the Tertiary control power programme is divided in ‘positive’ and ‘negative’, the Secondary control power programme still requires symmetric bids. The Primary and Secondary control power programmes require unlimited (24/7) availability. This challenge can be met by some industrial participants who may have loads such as cooling, heating etc., which can be aggregated and run at any time of day or night, but it remains an important barrier for commercial and domestic Demand Response as well as smaller industrial consumers.[202] Another critical issue in the product design of Secondary Control Power is that the dispatches are not according to a merit order list, but proportional to each unit’s individual share in the programme. As a result DR providers are being called at very low volumes at high frequencies.

3. Measurement & verification

Prequalification

The consumer/prosumer (or VPP) unit has to fulfil requirements as an aggregate. This simplifies the prequalification requirements, as it allows the aggregator to stand in the place of the consumer. Prequalification at the aggregate level is therefore an important enabler of Demand Response. There is no minimum size and no technical requirements for a single unit. Virtual generation units appear as single feed-in/out node for the TSO.

The aggregator/BRP monitors and regulates its pool at its own costs (including installation and maintenance) and provides the monitoring data to Swissgrid. The prequalification process is usually completed within 2-3 months.

Baseline methodology

The baseline is defined as the measured value of the load before being influenced by the aggregator. Its measurement is then set at the pre-qualifications stage.

[202] ibid. (retrieved on 4th April 2015)

Availability/utilisation payments

The Primary control power programme only provides an availability payment; currently prices are not attractive for Demand Response. Secondary and Tertiary control power – paid out with both availability and utilisation payments – provides the business case for aggregation and both receive an equal share in the aggregators' applications. The Swiss electricity market uses the 'pay-as-bid' system. This might change in the future due to standardisation at the European level following ENTSO-E's requirements, which are 'pay as cleared[203].

Product			Availability payments	Utilisation payments*	Access
Primärregelleistung[204]	Weekly	symmetric	23.14 CHF/MW/h	not offered	tender-based
Sekundärregelleistung[205]	Weekly	symmetric	28.28 CHF/MW/h	Based on SwissIX	tender-based
Tertiärregelleistung	Weekly[206]	Positive	5.64 CHF/MW/h	Based on SwissIX	tender-based
		Negative	3.94 CHF/MW/h	Based on SwissIX	tender-based
	Daily[207]	Positive	3.84 CHF/MW/h	Based on SwissIX	tender-based
		Negative	4.89 CHF/MW/h	Based on SwissIX	tender-based

* The agreement to reimburse based on SwissIX only applies to DR

Table 48: Overview of availability and utilisation payments in the balancing market in Switzerland

Penalties

There are two regimes of penalties.

- If the BSP fails to deliver the agreed curtailment, the penalty corresponds to the imbalance price of electricity.
- If the BSP has not reserved the power as planned in the bid and is directly responsible for it, the penalty is 10 times the price established in the bid. If indirectly responsible, (network constraints, works on power lines) the penalty is three times the price. This second type of penalty is rarely used.

203 The SEDC supports 'pay as cleared' as this can reward efficient low cost resources, encouraging them to enter a market while eventually driving down the costs.

204 Swissgrid (2015d): Weighted average prices in 2014, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/primary-control-power.html (retrieved on 4th April 2015)

205 Swissgrid (2015a): Weighted average prices in 2014, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/secondary-control-power.html (retrieved on 4th April 2015)

206 Swissgrid (2015b): Weighted average prices in 2014, available at: https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders/tertiary-control-power.html (retrieved on 4th April 2015)

207 ibid: Weighted average price of all six 4-hour periods (retrieved on 4th April 2015)

3

Results and conclusions

3.1 Overall Results

The following map provides an overview of the current regulatory framework for **Explicit Demand Response** in the 16 countries examined as described in section Methodology. The research shows that six European countries already provide a regulatory framework allowing for the development of Demand Response services: Ireland, Great Britain, Belgium, France, Switzerland and Finland. Although there are remaining regulatory issues Explicit Demand Response is a commercially viable product offering. Among this group, France and Switzerland stand out due to fact that they have restructured the roles and responsibilities of market participants specifically in order to enable independent aggregation.

Ireland has made significant progress in enabling demand-side resource participation in their market in 2014. Great Britain remains green due to its competitive energy market, open balancing markets and the fact that independent aggregation is enabled (though not fully described). However, Great Britain's leadership is now in question. The newly introduced Capacity Market does not place demand-side resources on an equal footing with generation, and now provides almost a £1 billion annual subsidy predominantly to existing generation facilities. (At the time of writing the market design is being challenged in the European Court).

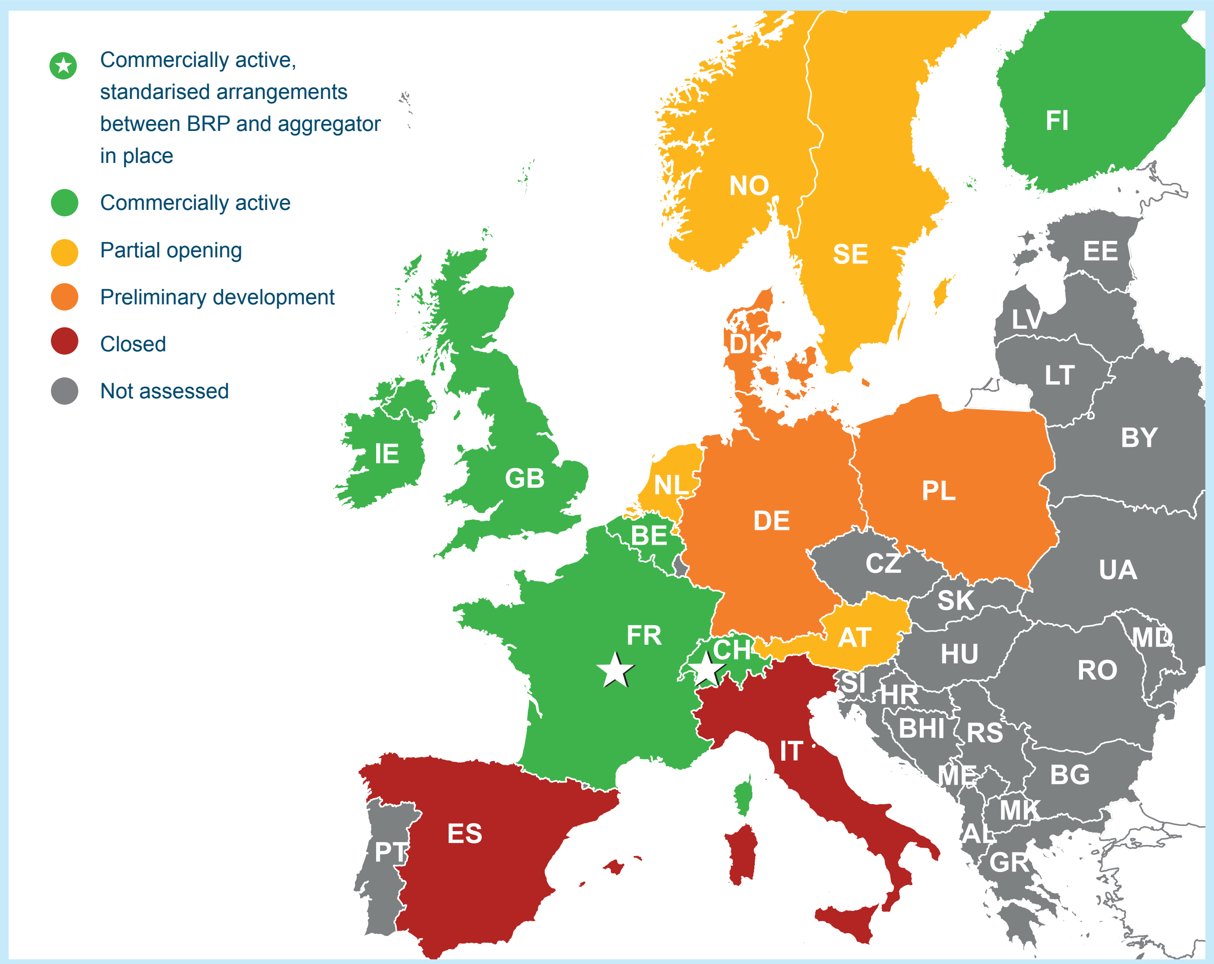


Figure 3: Map of Explicit Demand Response development in Europe Today (SEDC, 2015)

Finland and Belgium are green despite their lack of clarity surrounding the role of the independent aggregator. Both markets have created appropriate programme requirements and payment structures for demand-side resources; this is allowing market development while the surrounding regulatory issues are reviewed.

Sweden, the Netherlands, Austria and Norway are coloured 'yellow'[208]. In other words, while Demand Response companies are being established, regulatory barriers remain an issue and hinder market growth[209]. This is usually due to programme requirements which are not yet adjusted to enable both generation and demand-side participation. A lack of clarity around roles and responsibilities of the different actors also may block new entrants in the respective markets.

Germany, Poland and Slovenia are coloured orange, meaning that despite the gradual opening of their electricity markets to demand-side resources, severe barriers are hindering customer participation. For example, some of these Member States are lack a viable regulatory framework for measurement, verification, prequalification or competition between service providers, or have complex and generation-centred programme requirements, or even network fees designed to incentivise a flat consumption pattern, and hence penalise those who provide flexibility to the system.

Italy and Spain are coloured red because aggregated demand-side flexibility is either not accepted as resource in most markets or Demand Response services are not viable due to regulation. Here we see a critical disconnect between political promises and regulatory reality. While policies promise consumer rights and benefits, regulation hinders their delivery to consumers. The following table provide an at-a-glance overview of the analysis of Member States:

2015					
	Consumer Access	Programme Requirements	Measurement & Verification	Finance & Penalties	Overall
Austria	1	3	3	3	10
Belgium	1	5	1	5	12
Denmark	1	1	3	3	8
Finland	1	3	3	5	12
France	5	3	5	3	★ 16
Germany	1	1	1	3	6
Great Britain	3	3	3	3	12
Ireland	3	3	1	5	12
Italy	0	1	1	1	3
Netherlands	1	3	3	3	10
Norway	1	3	1	5	10
Poland	1	1	1	1	4
Slovenia	1	1	1	3	6
Spain	0	1	0	1	2
Sweden	1	3	3	3	10
Switzerland	5	1	5	5	★ 16
Overall	26	36	35	52	149
Max score	80	80	80	80	320

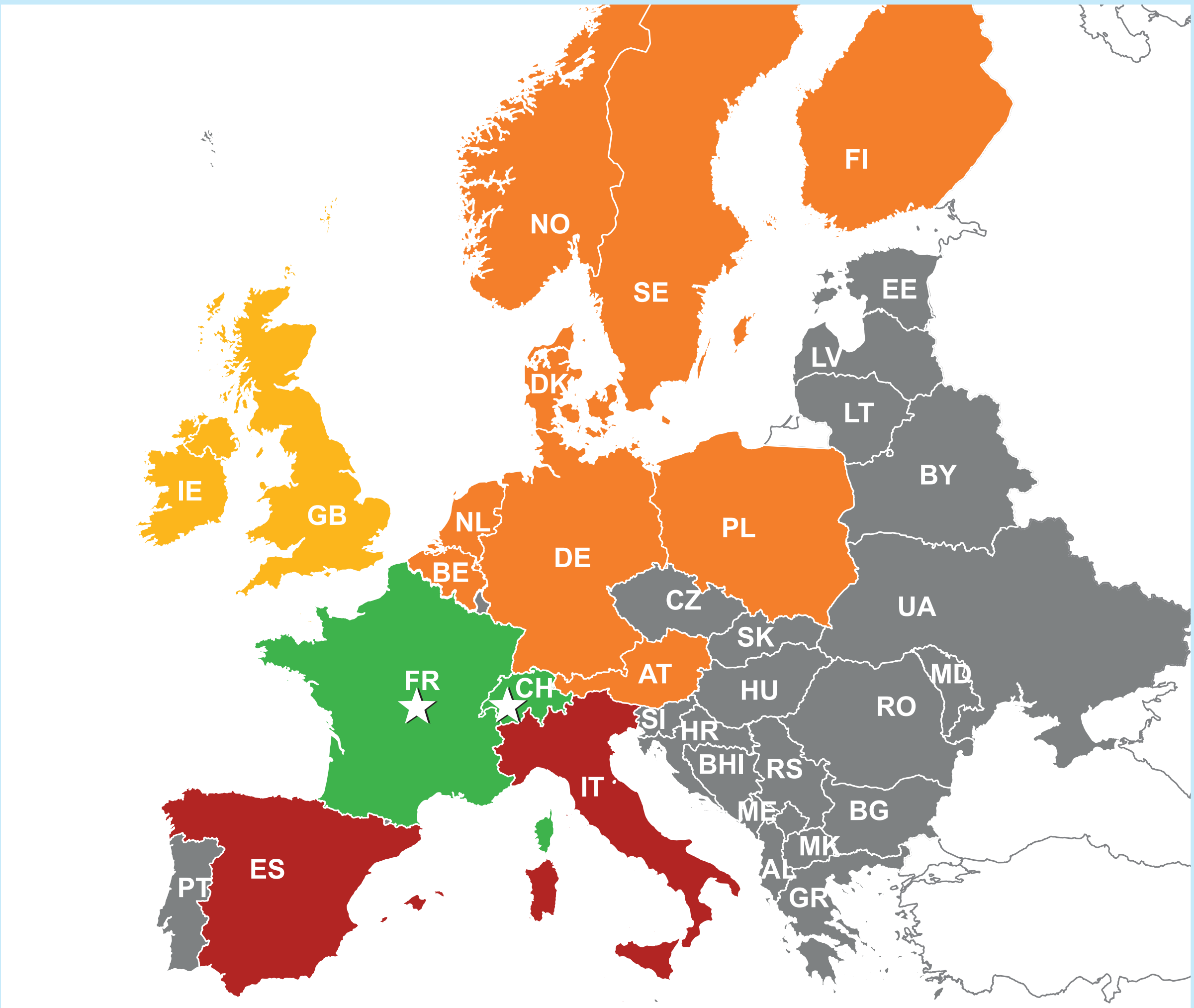
Table 49: Detailed grading of the countries assessed by the SEDC

[208] It should be noted that the Nordics are making significant progress in Implicit Demand Response through dynamic pricing. Smart Meter roll-outs are now close to completion throughout the region and it is a mandated requirement that dynamic hourly pricing should be made available to all consumers.

[209] It should be noted that although Austria is now coloured yellow, its markets for Explicit Demand Response may change to green, if the significant regulatory changes planned for 2014 are implemented successfully by the end of 2015.

The Member State analysis reviewed markets according to the four criteria described in 2.1 Methodology. These are: 1) Enabling consumer participation and aggregation 2) Appropriate programme requirements 3) Fair and standardised measurement and verification requirements, and 4) Equitable payment and risk structures. To ease comparison and clarify differentiation between Member States, the four maps below describe the results per criteria. The fifth and final map provides the final outcome when all of the results are tabulated.

Consumer Participation and Aggregation



Key: see section 2.1 Methodology

Figure 4: Map illustrating electricity markets' accessibility to Demand Response in Europe

Enabling consumer Participation and Aggregation appears to be the most problematic area across the countries examined. In several national markets Demand Response is not accepted as a resource in the balancing, capacity or wholesale markets. This directly contradicts the Energy Efficiency Directive Article 15.8 which states: "*Member States shall promote access to and participation of Demand Response in balancing, reserves and other system services markets, inter alia by requiring national regulatory authorities […] in close cooperation with demand service providers and consumers, to define technical modalities for participation in these markets on the basis of the technical requirements of these markets and the capabilities of Demand Response*".

Demand accepted as a resource

Certain Member States have made significant progress over the last year in opening their markets to demand-side resources. These include France, Finland, Belgium, Ireland, and Austria. Most Member States continues to have certain markets where demand-side resources are not accepted. Poland and Slovenia have both opened one of their balancing markets to aggregated demand-side resources. Italy and Spain, apart from the interruptible programmes, are almost entirely shut to consumer participation of any kind. While the German markets appear open, in practice, access is problematic due to a series of regulatory barriers.

The major hurdle remains the definition of clear roles and responsibilities for market actors

In a majority of Member States, the market rules do not allow for direct access of consumers to service providers and therefore a clear path to market. This is the main reason that several Member States with open balancing and wholesale markets, remain orange under Criteria 1. They may allow consumers to participate in the markets, but they lack fair competition between dedicated service providers who can engage these consumers. In these Member States, third-party aggregators are still required to negotiate bilaterally with BRP/suppliers, which is a critical barrier throughout Europe. This lack of appropriate definition of roles and responsibilities increases risk for all parties and enables abuse of consumer rights (including data privacy rights, adequate contractual arrangements, price stability). When roles and responsibilities fail to enable the clear and direct access of consumers to aggregation service providers, free market competition around Demand Response services is hampered.

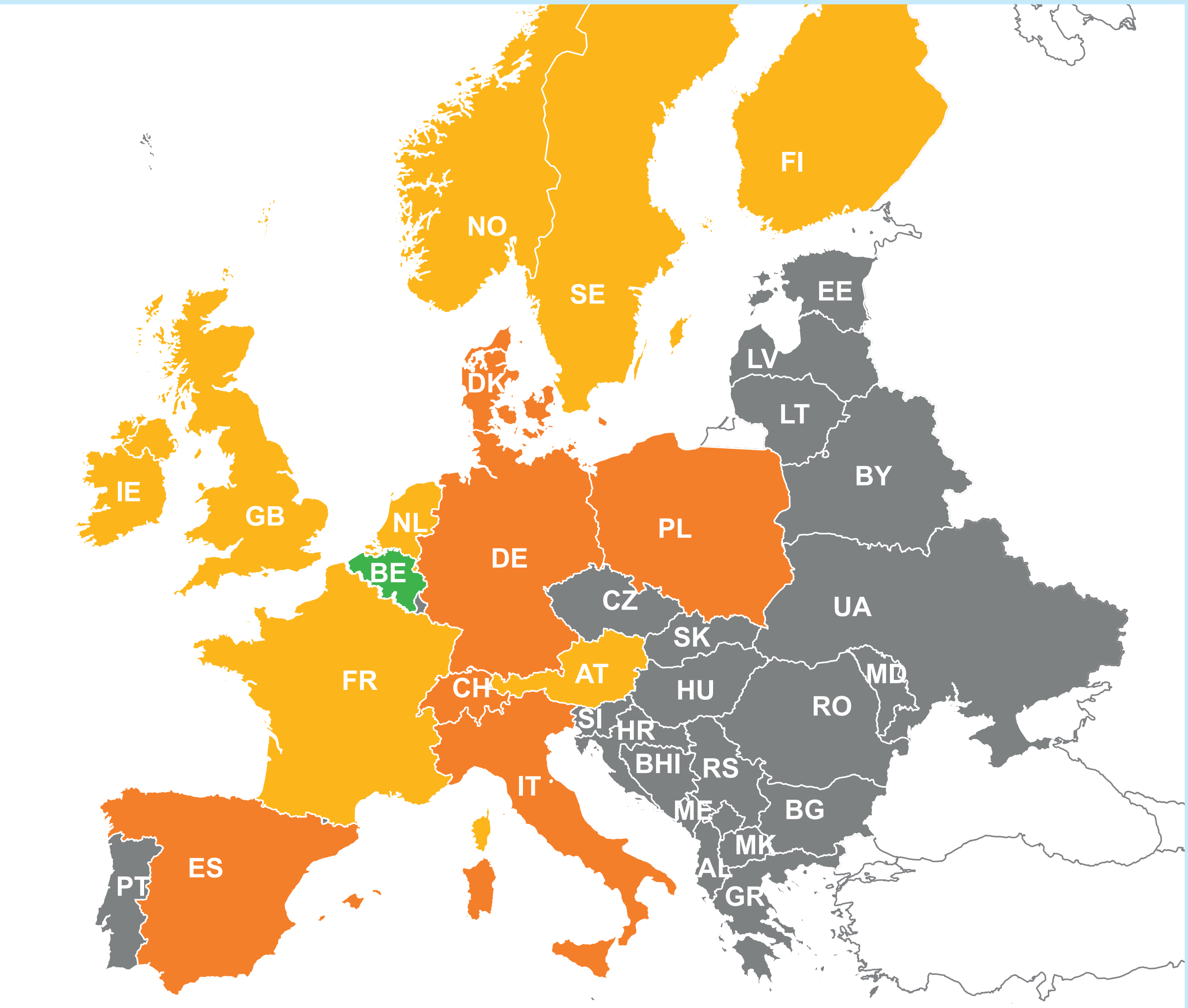
Only few countries provide workable market rules for Demand Response.

The only two countries which have regulated the issue are France and Switzerland. In these two countries, the regulators have made possible for third-party aggregators to contract with consumers without the supplier/BRP's agreement. Imbalances are neutralised by the TSO, whereas a sourcing price for electricity is defined centrally enabling the BRP to avoid being penalised by Demand Response activation. Belgium enables aggregation and is reviewing their current legislation. Other Member States, such as Austria and the Nordics have tried to lower the hurdles to becoming a BRP in the hopes that this would attract smaller new entrants.

In GB the issue has been ignored for the moment and Demand Response treated as part of the unpredictable consumers' behaviour. Therefore suppliers/BRPs have no right to block participation of consumers in Demand Response, but neither are they protected from risk or paid for lost energy sales. This is possible for the moment as the volumes of demand-side resources are relatively low. Ireland's system, by using a centrally dispatched model, does not have BRPs and makes the TSO the only one responsible for imbalances – therefore the entire issue is avoided.

Programme Requirements

The balancing market participation requirements were historically designed around the needs of generators. However, today these narrow criteria are no longer justifiable as they block low-cost demand-side resources and artificially inflate the cost of balancing. They also block consumer's possibility to earn from their ability to adjust when and how they consumer electricity. Many Member States are currently reviewing the regulation in place to accept a broader range of resources.



Key: see section 2.1 Methodology

Figure 5: Map illustrating accessibility of programme requirements to Demand Response in Europe

Though demand-side resources are more flexible and can react faster than most generators, large minimum bid sizes (over 5 MW) long DR event durations, frequency of DR events, internals between DR events (or resting periods between events) can be particularly decisive in the level of consumer participation. For example, while consumers can participate quickly and provide a secure resource, they will have difficulty being available 24/7 and for extended periods of time. (*see Annex III – Description of Product Elements & Best Practices* for more details).

Significant progress continues to be made, particularly in Belgium, Austria, France, Finland and Ireland. Denmark is undergoing a thorough regulatory review and may improve significantly in 2016. The Netherlands has historical programmes which continue to function and the status is stable.

GB remains yellow- this down from their green status in 2013-14, see national report for further details. In essence, Ofgem and DECC have found it difficult to take on-board input from stakeholders[210] and latest market developments therefore tend to be inappropriate or inadequate. (This is unfortunate but could be repaired in 2015-16 if desired, as the overall market structure requirements remain intact.)

In Germany, France and Denmark secondary reserves present availability requirements of 12 hours and 24/7. This requirement is significantly higher than the 1-2 hour standard but may favour conventional generation with higher cycling costs. Austria has decreased Tertiary Reserve's duration from 16 to 4 hours, enabling participation for a range of demand resources. A 4-hour duration is a significant improvement over 16 hours and is possible for an aggregator to manage.

Some regulators and TSOs may assume that national companies and households are simply not 'interested' in Demand Response – when in fact, historical and inappropriate programmes requirements may block participation. However, when the TSO and the regulator set out to improve programme descriptions, in order to allow a range of resources to compete, the efforts are generally successful[211]. Here dialogue and close cooperation with Demand Response providers, such as aggregators, suppliers and large consumers, has been a critical element in moving the markets forward, for example in Finland, France, Austria and Belgium.

Measurement and Verification

In many Member States the regulation concerning measurement and baseline methodologies does not yet exist. In other words, there are no standardised and transparent requirements for how energy consumption reductions should be measured and therefore also how they should be valued. This is one of the many hurdles consumers and service providers may face in the field of measurement and verification. These main barriers found in this area are described below.

Prequalification at the individual asset level is a critical barrier.

In Austria, Germany, Ireland and Poland the individual units of each pool of loads have to fulfil all technical and prequalification requirements – therefore aggregators are not able to protect consumers from these technical and difficult prequalification requirements and consumers are treated as large generation units.

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210 Unfortunately this can even be seen in the structure of stakeholders groups, for example the Capacity Market was advertised as enabling a range of resources, encouraging innovative solutions, yet the DECC stakeholder market design groups included only 1 demand response representative out of 15 stakeholders.

211 This process tends to require trial and error. The regulator and TSO need to better understand what will and will not be possible. The learning cycle can be shortened considerably if an open and positive relationship is established with consumers and aggregation service providers. A further description of programme requirements is provided in Annex III – Description of Product Elements & Best Practices.

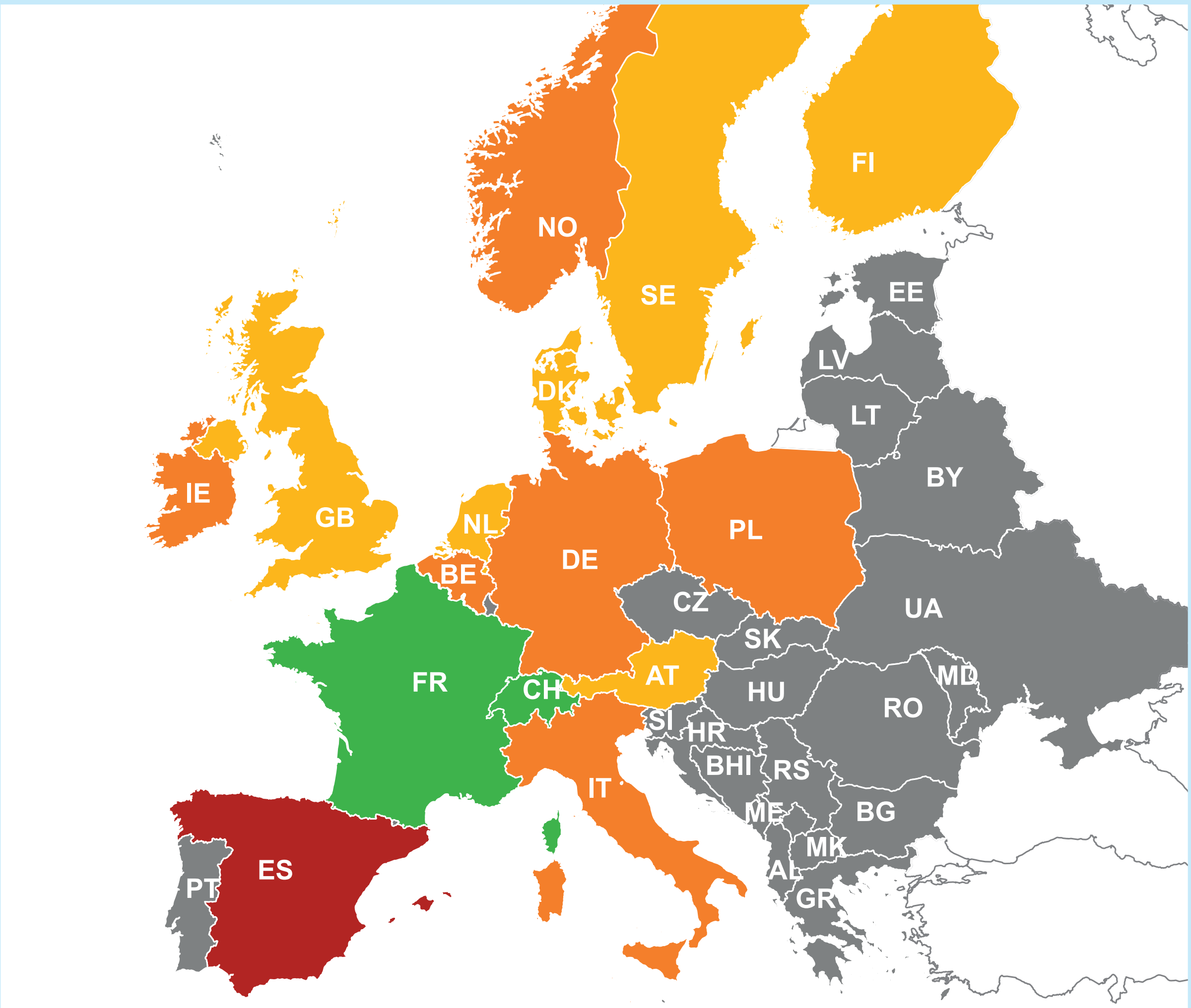
Measurement techniques can be problematic.

In Denmark and Norway, real-time metering is required by the TSO to participate in some programmes. This can represent an investment of €3,000 to €6,000 per site – whereas the majority of flexible loads sit within the commercial sector, in relatively small sites. On the opposite side, in Norway, the RPM is still largely based on manual phone calls, which restricts the potential of Demand Response, especially for small loads. '(A pilot project is currently running among the Nordic TSOs, where FRR-A bid size is reduced to 5MW, and the real-time measurement requirements are reduced/removed.

In Norway and other countries, it is impossible for an aggregator to pool load from different bidding zones. This limits the number and range of consumer sites available.

Baseline methodology may not be transparent or discriminate against consumer flexibility.

In Denmark, Sweden and Ireland, there is simply no public and standardised baseline methodology. In Germany and the Netherlands, the baseline setting depends on the contractual relationship between the end consumer, its BRP and its supplier. The absence



Key: see section 2.1 Methodology

Figure 6: Map illustrating measurement and verification development in Europe

of standardised requirements can act as a barrier. Moreover, the four German TSOs may establish their own criteria or have no publicly published criteria. This is a market barrier, as a consumer's consumption adjustments may be measured according to different standards.

The baseline may favour one resource against another and not allow tapping the full potential of demand-side flexibility. In Great Britain and Poland, the baseline methodology favours customer generation over load curtailment – this lowers the environmental value of Demand Response. In Belgium, the volatility of non-flexible energy consumption within one site cannot be separated from the available power flexibility.

DSO requirements may des-incentivise Demand Response.

Despite the requirements of the art. 15.4 of the Energy Efficiency Directive in several countries like Belgium or Germany, the prequalification process required by the DSO limits the available Demand Response potential and hinders Demand Response sourcing efficiency. Some DSOs have difficulty evaluating the potential congestion issues linked to market driven behaviour of DSO consumers and therefore tend to be cautious and discriminating towards allowing Demand Response. Currently the DSO is able to refuse consumer access to Demand Response without taking responsibility for the costs incurred by the consumer, aggregator and TSO, or even providing transparent measurement and risk calculation information used as a basis of the decision.

Payments and Penalties

Though penalties for non-performance are generally adequate and fair,[212] adequate payment for Demand Response is more problematic.

Demand Response may not have access to the most valuable markets

In Spain Demand Response can participate only through one interruptible load programme, but it cannot compete in the electricity markets. In Italy and Poland a very limited number of programmes are open to Demand Response, whereas generation has significantly more favourable participation conditions in competing programmes[213]. To a lesser extent the situation is comparable in Germany, where Demand Response does not have access to Cold Reserves.

The emergence of capacity markets has to be closely monitored. Great Britain was the first country to set up a dedicated capacity market, after the new rules for State Aid in Energy & Environment. Demand-side resources suffer a significant disadvantage and the scheme sets a dangerous precedent for bias. The setting up of the French, Italian or Polish capacity markets should provide a level playing field between generation and demand-side. So far, only the French capacity market is planning on enabling consumer participation, while it seems that the Italian and Polish market will put in place a generation- only scheme.

Availability payments are in most cases accessible for both generation and demand.

Availability payments are essential to secure investment in resource development. Most markets provide these payments to both generation and demand (assuming the market is open to demand at all). Poland represents a noticeable exception: the two programmes open to Demand Response do not provide availability payments, whereas these are available in the generation-only programmes.

[212] An exception appears to be the UK where consumer involvement in the Capacity Market may be blocked due to penalty design.
[213] An exception appears to be the UK where consumer involvement in the Capacity Market may be blocked due to penalty design.

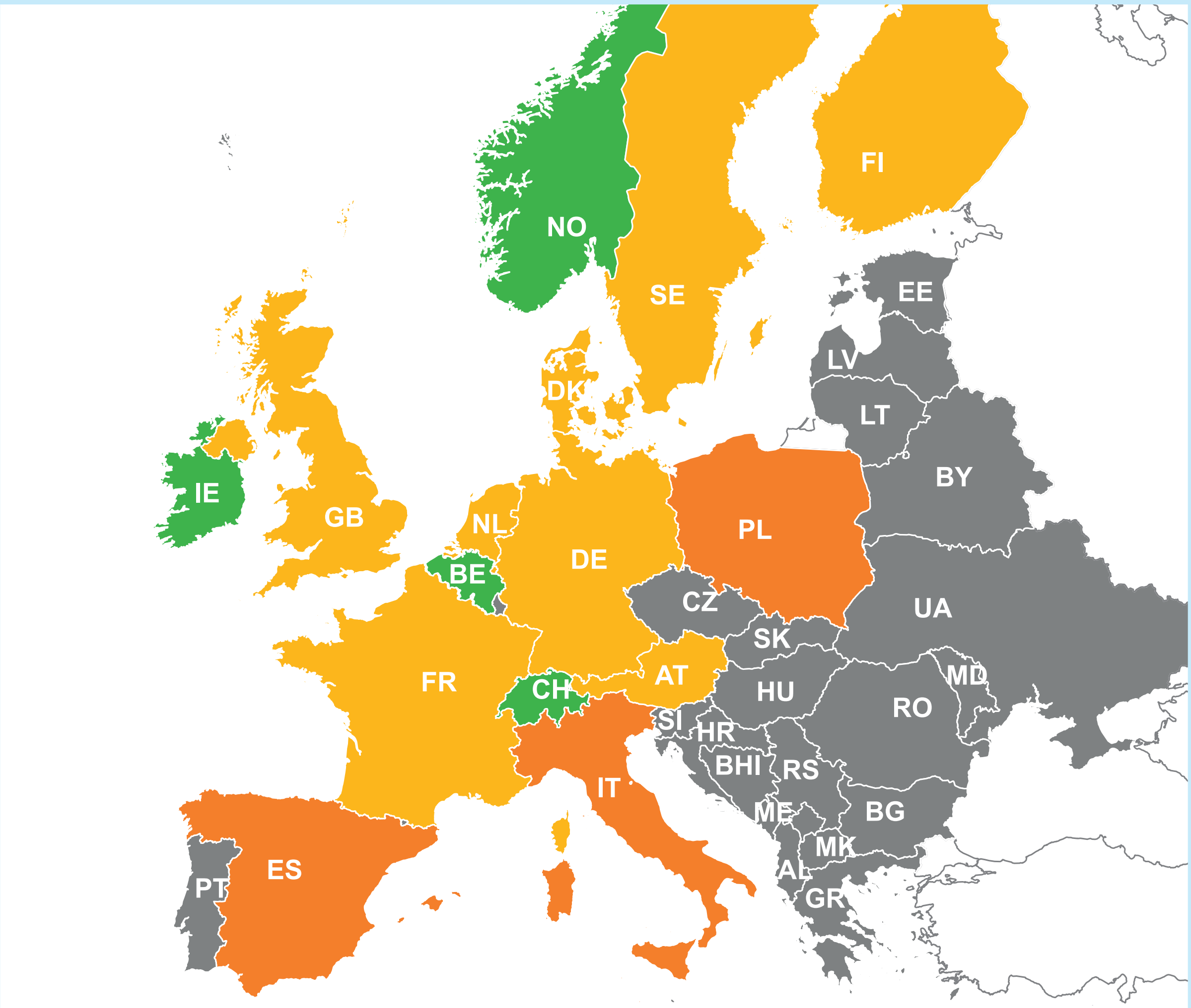


Figure 7: Map illustrating fairness and transparency of payment structures & appropriateness of penalties for Demand Response

Penalties appear generally well proportionated, but the level of the bank guarantees required may be inappropriate.

In the vast majority of cases, penalties appear well proportionated. Important penalties may occur in market where they're justified by the risk for the system (e.g. in primary control). In France or in Slovenia, significant bank guarantees are required from Demand Response service providers that may limit consumer ability to participate.

Reporting is difficult, market transparency is not always ensured.

Contracts may be negotiated individually and not be published. Standards of transparency and reporting must be created and enforced, both within the wholesale and balancing markets to ensure a level playing field and access of new entrants.

3.2 Conclusions

Though the measurable improvement between 2014 and 2015 is encouraging, the overall result of the SEDC review reveals multiple remaining barriers to the establishments of consumer centred Demand Response services. The study revealed three overarching trends:

1. **The regulatory framework in Europe for Demand Response is highly fragmented**

The EU Demand Response market is still in its early development phase and fragmentation is a result. Each Member State has a different regulatory framework and progress is not similar when it comes to opening up electricity markets to customer participation. This is a problematic development in the context of the aimed harmonised Internal Energy Market.

2. **There is a positive dynamic towards opening balancing markets to demand-side resources**

In many European countries, regulators and TSOs have been improving the programme requirements of their different balancing products to enable demand-side resources participation (e.g. in Austria, Belgium, Finland and France). Positive dialogues have also been established between TSOs and service providers to improve the definition of baseline methodologies.

3. **In the majority of countries consumer access to Demand Response service providers is problematic**

Consumers have the choice to select any third party provider of, for example, energy management services they like. However, in most European markets, consumers cannot choose a separate services provider for providing Demand Response. They are restricted to their supplier, or at least need their supplier's permission before working with a third party aggregator. Often the supplier is in direct competition with the aggregator, or may have other reasons to hamper the uptake of Demand Response, and thus has an incentive to block the aggregator from doing business with the consumer.

In the majority of the countries examined, the roles and responsibilities are unclear, and do not allow for direct access of consumers to service providers, therefore they do not offer them a clear path to market. The more in-depth the analysis, the more this issue is understood as a critical barrier throughout Europe to the development of consumer oriented services and Demand Response. There is therefore an urgent need to clarify the role of new market participants, such as third party aggregators, and their interaction with existing market participants, such as BRPs/suppliers when helping consumers sell their flexibility into the market.

The research shows that the only two European countries have put in place standardised arrangements between the two market actors, namely France and Switzerland. Despite the strengths and weaknesses that one can find in the frameworks implemented in these two Member States, they have minimised risks for all parties and have enabled consumer access to the markets via independent aggregators.

The electricity markets were deregulated specifically to enable improved consumer services through market competition. Yet today, Member State regulation continues to stand in the way of these very services, breaking the promise made to European citizens when deregulation took place.

The SEDC would call on the Commission to oversee the coordination of regulatory initiatives and the creation of Demand Response development plans at the Member State level. The Energy Efficiency Directive mandates in Article 15.8 "*Member States shall ensure that national regulatory authorities encourage demand side resources, such as Demand Response, to participate alongside supply in wholesale and retail markets"*; yet this is far from the case today. The greater the coordination between Member States, the greater the economies of scale and the more robust Demand Response services become: lowering the cost of intermittent generation, improving the efficiency of the grid and lowering the cost of balancing and peaking reserves – while providing an important new source of revenue for local businesses and households.

Taking into account the potential benefits of Demand Response and the regulatory barriers in place – clear step-by- step **demand-side strategic plans**[214] will be required at a European and Member State level to ensure real progress. These should include logical targets for market development of consumer demand-side services, measured and verified against well-defined key performance indicators. Only a planned and coordinated effort can hope to overcome the systematic historical barriers to Demand Response.

It is time to bring our electricity markets into line with Europe's overarching energy objectives. The European Network Codes and the upcoming Electricity Market Design Initiative create an opportunity for unification and standardisation of regulation on demand-side flexibility, including clarified roles and responsibilities at the European level across Member States. It is now clear that the full potential of the European internal energy market will be only realised if consumers – households, businesses and industry – are empowered to participate in the European Union's energy transition. This has to be one of the goals of the market design and will require a fundamental change in the role of the consumer is in the electricity market.

[214] Adaptable according to the national contexts. Theses adaptations need probably cost benefit analysis in each country members to determine pertinent targets for DR development.

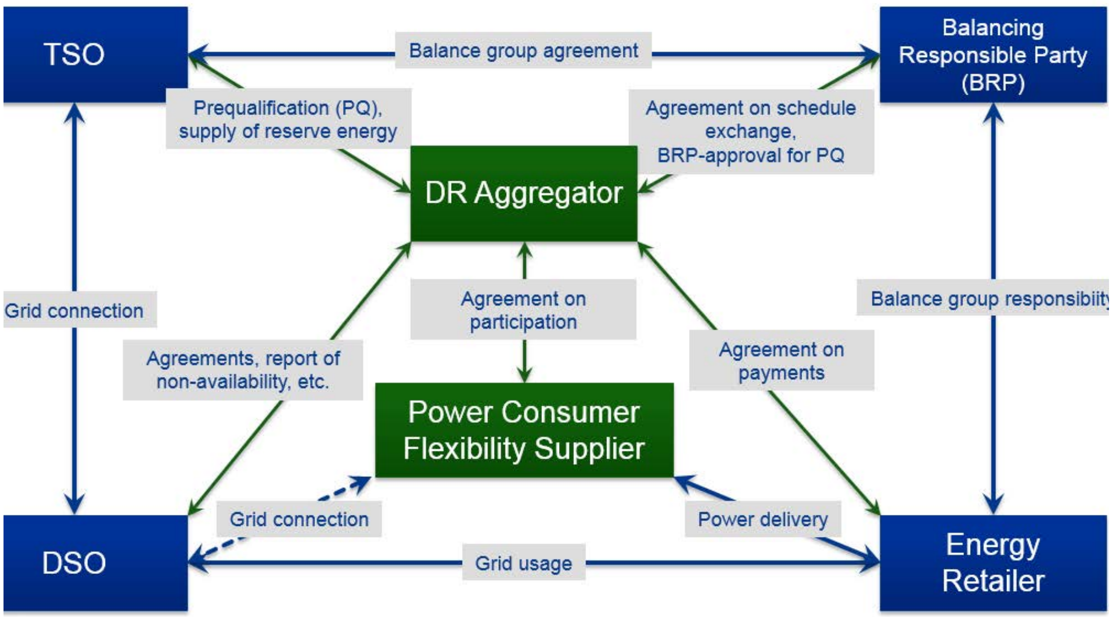
Annexes

Annex I – Contractual Relationships

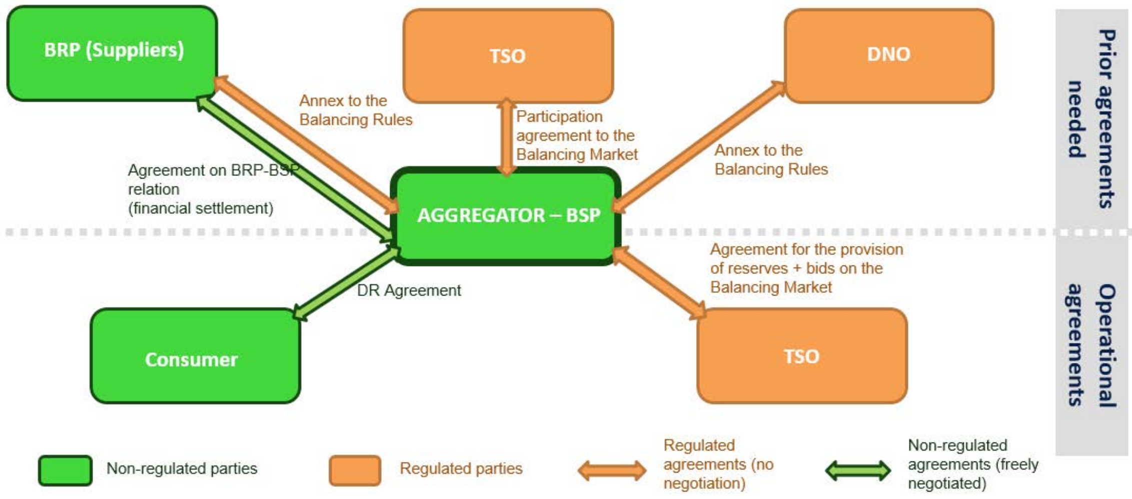
The requirements, place and potential of Demand Response in organised electricity markets

Demand Programmes – contractual relationships

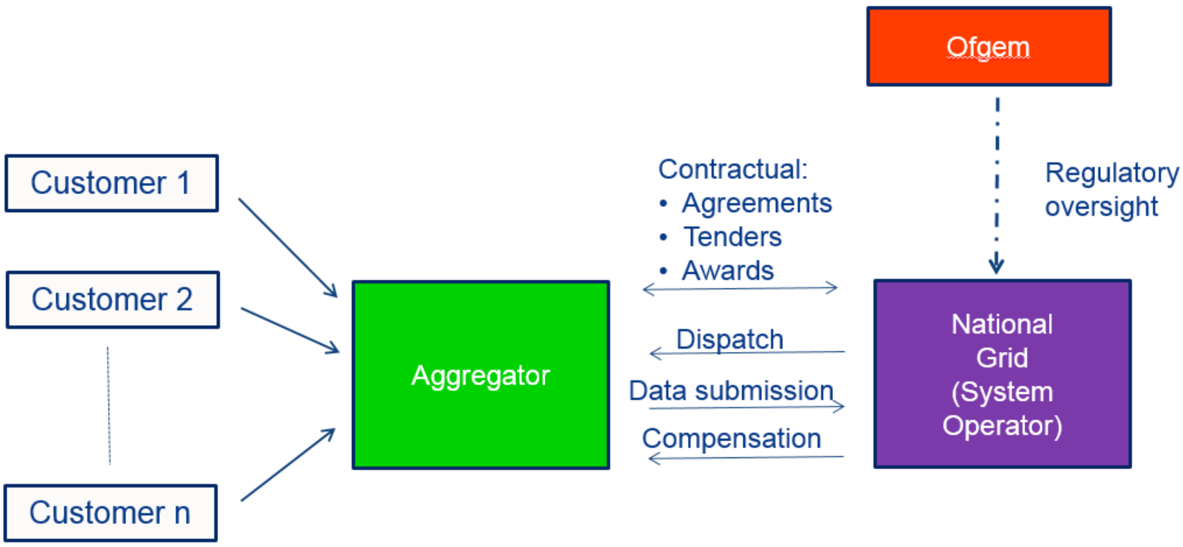
In today's European energy markets Demand Response aggregators are faced with many stakeholders to whom a contractual relationship needs to be established before the flexibility potential of any single participating site (whether it be an industrial, commercial, institutional or residential customer) can be commercialized into the markets (e.g. as balancing power). Find below the examples of Germany, France and UK.



Demand Response in today's market design (example Germany). Source: EnerNOC



Demand Response in today's market design (under experimentation, example France) Source: Energy Pool



Demand Response in today's market design (example UK). Source: EnerNOC

In order to establish a market design this is scalable, transparent and avoids any market abuse by well-established or dominant players (e.g. the Balancing Responsible Parties (BRPs), responsible for the settlement of balancing groups deviations) adequate sets of rules, standardized processes and legal security are needed.

In order to establish a scalable Demand Response market across European member states, the following aspects need to be solved:

- **Define explicitly the role of a Demand Response provider / aggregator; such role can be performed by:**
  - An energy supplier, or
  - An independent Demand Response aggregator, or
  - A grid operator or a Balancing Responsible Party (BRP)
- **Establish standard reimbursement for BRP**
  - Establish a standard reimbursement for BRP whose energy was redirected without their knowing, e.g. EEX, or a regulated fee
- **Financial support in the development phase of Demand Response / Aggregators**
  - Dedicated mechanisms with capacity/flexibility payments
- **Establish an "obligation to play along"**
  - All stakeholders have to play along with the Demand Response provider
  - Establish reaction times, service levels
  - Establish penalties in case of non-compliance
- E**stablish standard (template) agreemen**ts

All stakeholders need to operate on the basis of standard agreements, processes, data formats and protocols, payments, incentives, and penalties

- **Define standard processes**
  - Define stakeholders, use cases, time lines, and data exchanges
  - Define service levels, reaction times and quality mechanisms
  - Define incentives and penalties for non-compliance
  - Use the established national market communication standards, e.g. MaBiS[215]
- **Define (a) common data formats and communication protocols**
  - Identify stakeholders
  - Define content and format of data
  - Use the established national market communication mechanisms, e.g. EDIFACT[216]
- **Define technical standards**
  - Metering
  - Communication protocols
  - Service levels
  - Reliability and security levels
  - Establish a baseline and Demand Response metering methodology

[215] Market rules for the processing and settlement of balancing group deviations of electricity (in Germany called MaBiS). See also the requirements of the Electricity Grid Access Regulation (StromNZV) on the establishment, handling and accounting of balancing groups in close cooperation with the operators of the electrical power networks in the specific control areas.

[216] Electronic Data Interchange for Administration, Commerce and Transport (EDIFACT). The EDIFACT standard provides: a set of syntax rules to structure data, an interactive exchange protocol (I-EDI), standard messages which allow multi-country and multi-industry exchange.

- **Incentives for scaling, e.g.**
  - Establish market sub-segments for Demand Response, e.g. “minute reserve by Demand Response”, “secondary reserve by Demand Response”
  - Quotas for Demand Response: “a minimum percentage x% of reserve energy must be provided by Demand Response”
  - Pay the energy reimbursements for BRP out of the general grid fees (not by the Demand Response provider)
  - Allow for aggregation and develop programmes compatible with Demand Response strengths & weaknesses and including a distinction between implicit Demand Response (service primarily offered to the BRP) and explicit (service to the TSO or system)
- **Penalties for non-participation**
  - Plant operators who do not participate significantly in a Demand Response programme cannot apply for national subsidy schemes, tax-exemptions, or other levees. E.g. in Germany: Renewable Energies Act levy (“EEG-Umlagenbefreiung”) or grid system usage charge exemption (“Netzentgeltbefreiung”).
  - Grid operators who do not operate significant Demand Response programmes cannot benefit from incentive programmes / schemes or do not receive full reimbursements. E.g. in Germany” a change in the incentive regulation (“Anreizregulierung”).
- **Prioritize and coordinate multi-participation**

Several players, better all players, must be incentivized to introduce Demand Response programmes

  - However, the participation of a plant in several Demand Response programmes, needs to be incentivized, prioritized, and coordinated
- **Remove historical hurdles**
  - If a provider produces negative reserve energy by increasing their net power consumption, the peak in loads must not lead to an increase of grid fees

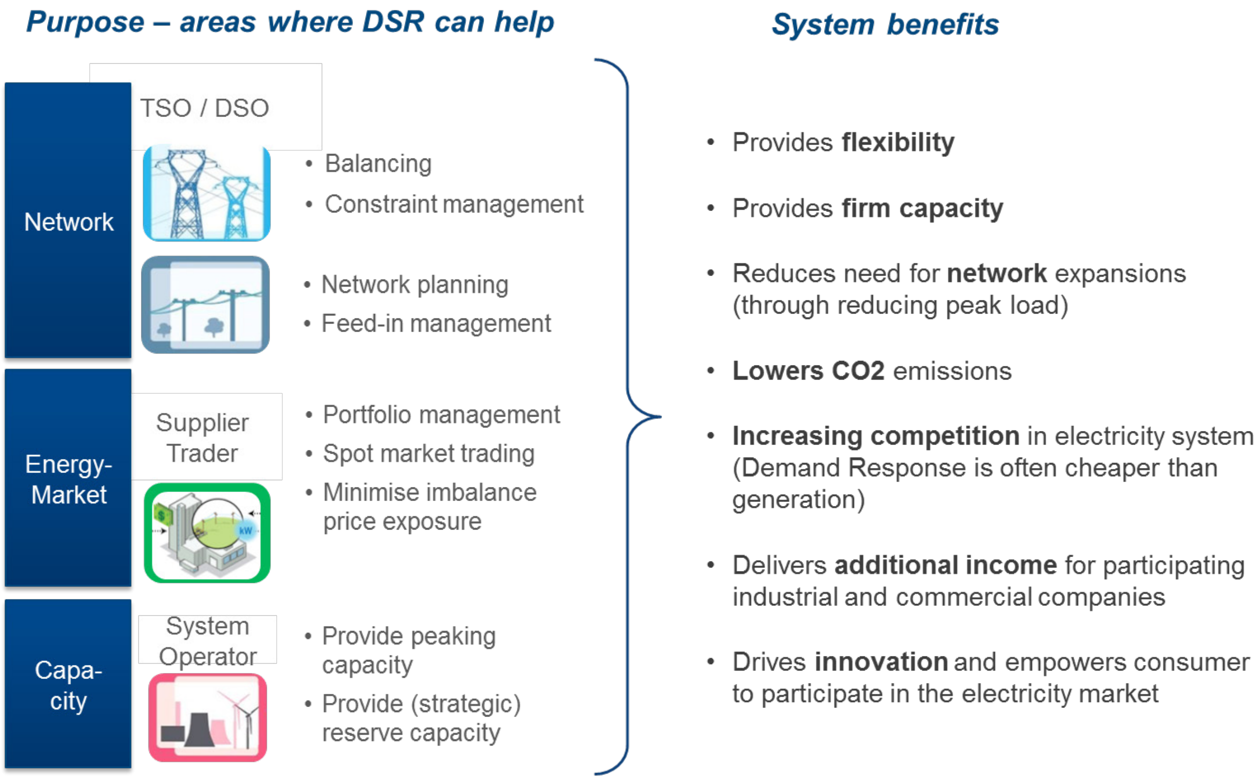
Demand Response – overview of parties trying to control demand-side assets

In today’s energy only markets there are basically five parties trying to control the same demand-side resource: first of all the resource owner (“plant operator”), the DSO, the TSO, the Balancing Responsible Party (BRP) and (potentially in the future) through Flexibility / Capacity Markets.

Based on above it becomes pretty obvious that a kind of prioritization and coordination between the parties involved is necessary. Such a coordination role can be taken up by an aggregator, whether the aggregator’s role is executed by the DSO, TSO, BRP and/or an independent 3rd party aggregator (a new role not established yet in the existing market frameworks). Further, standards are necessary to be defined with regards to roles, agreements (contracts), processes, data formats, protocols, technical standards, fees, and (incentive) payments.

Annex II – Demand Response is a multi-purpose resource

Demand response can be used for many purposes in the electricity market, and delivers significant benefits to the system as a whole.



Purpose areas for Demand Response and resulting system benefits (Source: EnerNOC)

Annex III – Description of Product Elements & Best Practices

Below is a standard list of elements, which make up a Demand Response product description, along with a short explanation of best practice principles. These general guidelines reflect the capabilities of demand-side resources:

- **Full Activation Time (call time):** The more time consumers have to prepare for an event, the higher the participation level and the lower the cost.

- **Minimum and maximum quantity:** The minimum quantity should be as low as possible. For example in the spot market in the Nordics consumer can bid in 100 W; in several markets in Europe the minimum quantity is 50 MW. The 50 MW limit is usually due to the fact that the TSO uses a telephone to call on resources manually. The SEDC would suggest that TSOs should be willing to employ a more advanced level of communication technology. This is a critical market barrier to new entrants. Acceptable minimum bid sizes are 3-5 MW depending on the size of the market.

- **Price of the bid:** 1) Prices should be transparent and communicated in advance. 2) They should also be the same for all market players, including consumers. 3) Markets that are pay-as-cleared (PAC) are significantly easier for demand-side resources to flourish in than Pay-as-Bid (PAB). This is due to the fact that the lower cost solutions will earn extra income in a PAC market. The aggregation service provider can then use this income to engage a wider range of consumers, building a larger demand-side resource.

- **Divisibility (minimum and max load amounts):** There should be no minimum load size for any single consumer who joins an aggregated pool. This should be set by the service provider, not the TSO (or the DSO).

- **Duration of the event:** As short as possible. The longer a consumer must turn off or down a device, the lower the level of participation and the higher the cost. It makes sense to have multiple, short bidding periods rather than one extended period in order to allow demand and distributed renewable resources to participate at a lower cost.

- **Mode of Activation:** A description of how a device is turned on. This should be between the TSO (Supplier or DSO) and aggregation service provider – not necessarily the individual consumer. Communication and activation of the consumer is the aggregator's role.

- **Frequency (total number) of activations:** In most markets, the fewer the activations, the higher the level of demand-side resources will be and the lower the cost[217]. Again here it is beneficial to have shorter bidding periods, so that the consumer does not have to be active continuously for an extended period of time.

- **Intervals (time) between activations:** The intervals should be as long as possible or the bidding period should be short. (For example a TSO may require a consumer to be available every 30 minutes, but only for a 2 hour bidding period).

- **Call Method:** This is sometimes not necessary for generators and therefore may not be included at all in a programme description. However, consumers are going to need to be informed of when there is

[217] The number of activations will not be as important in a frequency market; here it is the duration of the activations which will be critical.

an event. They will not continuously participate in a market. It is therefore important to include a call method in a programme description.

- **Measurement and communication requirements:** Should be well defined and robust, but also consumer appropriate. In certain markets the same measurement and communication requirements are used for a 500 MW power plant and a household. This is a market barrier and unnecessary for system security.

- **Penalty requirement:** Penalties for non-compliance should be fair and should not de facto favour one resource over the other. A consumer will not participate in a market where, for example, they will need to pay back 101-150% of all their annual revenue for a year. The business model of Demand Response providers and consumers must be taken into account when constructing penalties.

Annex IV – Measurement, Verification and Baseline Configurations

Below is a description of the measurement and verification protocols needed to ensure reliable delivery of demand-side services in a manner that will still enable strong resource development.

Product Delivery: Performance Measurement

Performance measurement, which is typically termed Measurement and Verification (M&V), is the process of quantifying and validating the provision of the service according to the specifications of product. The performance measurement process usually occurs at three stages:

- To qualify potential resources against product specifications as an entry gate to participation

- To verify resource conformance to the product specifications during and after participation

- To calculate the amount of product delivered by the resource as part of financial settlements

All resources should be held to the performance specifications established by the product. However – demand-side and generation-side communication requirements will usually need to be designed separately and made appropriate to each. Technical rules often proscribe the use of metered values to base performance and settlements.

Measurement

Another important aspect of performance measurement is the customer site metering configuration for determining both the historical baseline of the facility, and the actual consumption of the facility during the time of delivery of the Demand Response product; i.e., the Demand Response event. Separate from the consideration of communication requirements addressed below, the metering configuration accounts for the specific Demand Response approaches, or measures, that the facility employs when delivering. For example, a very simple case might be that of a facility that chooses to reduce its consumption of power when an event is called, and such case may involve only the measurement of power consumption at the facility meter with the local distribution company. But in another case, the facility may employ multiple measures, for example, a behind the meter generator, and it may be appropriate and necessary to meter both the facility meter with the distribution company and the output of the generator, and appropriately combine the results of both.

Product Delivery: Communication Requirements

An essential element in establishing a level playing field rests on clear rules around communication requirements. It is important that the communication requirements recognize that if not prudent in understanding exactly what the system operator needs for the specific product, onerous communication requirements can pose a cost barrier to Demand Response participation. For example, technical rules often require real-time SCADA communication with dedicated redundant telecommunications to each and every consumer providing balancing services, since they have traditionally been associated with large central generators. This is cost-prohibitive and impractical for smaller, non-generating resources that could nonetheless still meet the performance specifications of the product.

For example, in order to communicate performance data effectively from the customer to the system operator, there are several issues that need to be addressed within the scope of telemetry: frequency of interval readings, accuracy of the information, timeliness of reporting those intervals to the system operator, and the communication protocols for reporting that data to the system operator. However the meter technology need not always be "smart" especially in the case of smaller consumers. Interval meters can also be used, depending on the programme type.

Frequency of interval readings

The frequency of interval readings depends primarily on the type of product being delivered. For example, regulation services may require reporting intervals between 2 seconds to 1-minute intervals, and the response requirements to system conditions may be sub-second. As a result, these applications may require direct communication between the customer site and the grid operator. Spinning reserve markets may require 1-5 minute intervals, while for most other programmes, reporting intervals of 15 minutes to 1-hour intervals are appropriate. **More importantly, for all but the regulation services, direct communication between the customer site and the grid operator is not a requirement, rather the consumer should have the opportunity to communicate directly with the Demand Response service provider**.

Accuracy

Generally, in most Demand Response programmes in the US and other markets, the accuracy of the reported metered data to the system operator must fall within +/- 2% of the metered readings of the customer's settlement data with the local distribution utility. The requirement for any greater accuracy should be carefully considered in light of the fact that any inaccuracies are likely to be unbiased, and in light of the fact that collection of meter data, aggregation of that data, verification of the accuracy of that data, and submittal of the data to the system operator is a major cost driver and a major consideration in what type of facilities may be able to participate in the market or programme. However, data collection and aggregation, verification and submittal of data shall always be aligned with requirements of the market and its participants. This needs to be incorporated in the market design from the beginning.

Timeliness

Generally, interval data submittals to the system operator are not required to be in near time, or near real time. Most programmes and markets in the US only require monthly uploads of data to the system operator. Again, the requirements should be based on the specific needs of the system operator, keeping in mind that any requirements for near real-time submittal of data places additional burdens on the customers and the 3rd party aggregators, and adds significantly to the cost of delivery of the Demand Response product. This is especially true if one of the goals of the market or programme is to grow the Demand Response participation, as the costs per customer for delivering real time data may preclude the participation of small C&I, and residential customers.

Protocols

Communication protocols will depend on the system operator and the specific communications protocols that are utilized by that entity. Ideally standardized communication protocols should be supported if they are available, however aggregators and service providers should not have to wait for these standards to appear. In order for Demand Response to be effectively integrated into system operations, the communication protocols must be consistent between different types of resources that report into the system operator. Generally, in all markets today, those protocols make use of the latest in communication technologies and the cost effectiveness of those technologies, and it is simply impractical to impose specific protocols universal to all system operators.

Baseline Methodology

An essential part of establishing a level playing field for demand-side resources includes the use of a historical baseline which determines the consumption that would have occurred "but for" the actions taken by the customer in response to dispatch notification. There are many different baseline methodologies in use, dependent on the market and product, and there is no "one size fits all" best approach. But there are some basic principles to the selection of that methodology. Baselines should balance accuracy, simplicity and integrity. Baselines have been designed, and should be incorporated, that produce statistically valid and consistent results, that produce results that are unbiased in either over-predicting or under-predicting actual performance. There are numerous reliable methodologies and ICT solutions that are able to establish reliable baseline values that are in current use throughout the world, and it is not necessary to re-invent the wheel when implementing Demand Response into a market design.

Sample choices:

1. Assess consumption over the previous ten days and assume consumption during the capacity call would have been an average of the five highest of those days

2. Assess consumption over the previous ten days and assume consumption during the capacity call would have been an average of the five highest of those days, adjusted upward by some weather factor

3. Compare consumption in the period of time immediately preceding the call, with what the resource is consuming during the call

For further information and more examples on Baselines please see Annex V

Further critical elements required to measure and verify a Demand Response activation are: metering configuration, product delivery, communication requirements, frequency of interval readings, accuracy standards, timeliness of measurement data and communication protocols.

Examples and sources for baseline methodologies

Typical Demand Response programmes rely upon incentivizing energy users based on the extent to which they reduce their energy consumption and therefore require a reliable system to measure energy reduction. For this reason the measurement and verification of Demand Response is the most critical component of any programme. The baseline is the primary requirement for measuring curtailment during a Demand Response event.

A baseline is an estimate of the electricity that would have been consumed by a customer in the absence of a Demand Response event. Baselines enable grid operators and utilities to measure performance of Demand Response resources. A well-designed baseline benefits all stakeholders by aligning the incentives, actions, and interests of end-user participants, aggregators, utilities, grid operators, and ratepayers. Baselines are a challenging aspect of Demand Response programmes because they must represent what the load would have been if a customer had not implemented curtailment measures. In other word, a baseline is a "counter-factual," a theoretical measure of what the customer did not do, but would have done, had there not been a Demand Response event.

The measurement and verification (M&V) generally, and the "baseline" more specifically, of Demand Response determines the magnitude of the resource and thus plays an important role in determining the value it has to the electric system. M&V also drives customer compensation for participation, and as a consequence, will influence the number and types of customers for whom the Demand Response programme appears attractive. Good baseline design is driven by adherence to three fundamental pillars: accuracy, simplicity, and integrity. While no baseline is perfect, baselines that balance these principles are better than those that do not.

Accuracy

Customers should receive credit for no more and no less than the curtailment they actually provide, so a baseline method should use available data to create an accurate estimate of what load would have been in the absence of a Demand Response event.

Simplicity

The baseline should be simple enough for all stakeholders to understand, calculate, and implement, including end-use customers. In addition, it should be possible to determine the baseline in advance of or during Demand Response events, so that it can be used to monitor curtailment performance in real time.

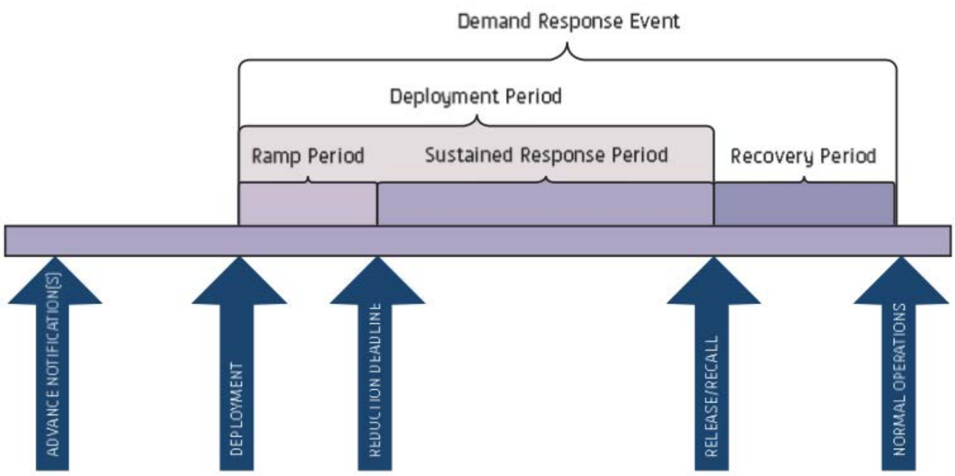
Integrity

A baseline method should not include attributes that encourage or allow customers to distort their baseline through irregular consumption nor allow them to game the system.

Balancing these traits is not simple. In some cases, a baseline resistant to manipulation can be so complex as to be unworkable by programme stakeholders. On the other hand, the simplest approaches could allow market participants to exploit the baseline in their favour. Therefore, baselines should be evaluated to ensure they provide for all three attributes of accuracy, simplicity, and integrity.

A Demand Response event has three phases of curtailment.

- The **ramp period**, which begins with deployment, is when sites begin to curtail.
- The **sustained response period**, which is the time period bounded by the reduction deadline and the release/recall, is the time in which the Demand Response resources are expected to have arrived and to stay at their committed level of curtailment.
- The **recovery period**, which occurs after customers have been notified that the event has ended, is the period when customers begin to resume normal operations.



The stages of a Demand Response event. Source: EnerNOC

Basic Baseline

Baseline is the electrical load that the customer would have consumed in the absence of an event. Actual meter data from the period of the event is compared with this baseline to determine the customer's curtailment. When a customer enrols in a Demand Response programme, engineering specialists working for a utility or aggregator help identify the committed capacity—the capacity that a customer will be expected to provide during an event based on the nature of its operations and its curtailment plan. Once a baseline is generated for a customer, a second line can be created to show the committed capacity, or the usage level that a customer must remain at or below during an event. Suppose that a deployment occurs at 11:00 am and the customer begins to decrease energy usage in preparation for the 12:00 pm reduction deadline. Performance can be tracked by comparing the committed capacity to the actual meter load.

Primer on Baseline Types

There is no perfect baseline — they are all estimates. Some baselines are more appropriate than others based on programme type, customer type, and/or programme season. Factors such as the conditions that trigger a Demand Response event, the frequency of Demand

Response events, timing of notification, and duration of event lead to discrepancies between the optimal baseline characteristics for different programme types and customers.

In its publication of Demand Response standards, North American Energy Standards Board (US) defined five categories of baseline methodologies:

- **Baseline Type I** – baseline is generated using historical interval meter data and may also use weather and/or historical load data to generate a profile baseline that usually changes hour-by-hour

- **Maximum Base Load** (also known as Firm Service Level in PJM) – uses system load and individual meter data from the past Demand Response season to generate a flat, constant level of electricity demand for the baseline that the customer must remain at or below

- **Meter Before – Meter After** – baseline is generated using only actual load data from a time period immediately preceding an event

- **Baseline Type II** – statistical sampling generates a baseline for a portfolio of customers in the instances where interval meter for all individual sites is not available

- **Generation** – baseline is set as zero and measured against usage readings from behind-the-meter emergency back-up generators. This type of baseline is only applicable for facilities with on-site generation and is not discussed in this paper.

- Baseline methodologies differ in regards to baseline shape, type of data used, timeframe of historical data, and programme objective and design. Below are several examples of baseline methodologies used in the United States[218]:

[218] Joule Assets (2013)

ERCOT	
Description	**Example Programmes**
There are three major methodologies. ERCOT will determine which is the most appropriate for any particular load. The first is a Statistical Regression Model, which is a function that predicts a customer's load based on a variety of variables, such as weather and day. The second is the "Middle 8-of-10 Preceding Like Days Model". This method looks at the 10 most recent days that have the same "day-type" as the event day. The days of highest and lowest consumption are removed, leaving 8 days. A "day-type" can be one of two classifications: Weekday (Monday through Friday excluding holidays) or Weekends/Holidays (Saturday, Sunday, and ERCOT holidays). The average consumption during each hour across these 8 days is considered the baseline. The third is the "Matching Day Pair Model". The baseline will be the consumption during the same hour on the same day of the previous year.	Emergency Reserves Service (4 hour reserves) Responsive Reserves (10 minute reserves)

PJM	
Description	**Example Programmes**
The “Highest 4 of 5” Method is used for Economic Demand Response and can be used for Emergency Load Response as well. Select the five most recent non-event days, excluding any weekends, holidays, or days when a Demand Response event was called. Replace any excluded days with the next valid day. For each of the 5 days in the window, calculate the Average Daily Event Period Usage, which is the average of the participant’s hourly usage over the event hours in the day, and the Average Event Period Usage Level, which is the average of the Average Daily Event Period Usage values. Exclude any day in the window for which the day’s average daily event period usage is less than 25% of the average event period usage level. Replace any excluded day with the next valid day. Rank the final five days used in the window and eliminate the day with the lowest Average Daily Event Period Usage. With the remaining four days, calculate the Average Event Period Usage level. Note that they use the highest 4 of the 5 previous days if the event is on a weekday, but they use the highest 2 of the 3 previous days is the event is on a weekend.	Economic Load Response (energy) Emergency Load Response (capacity)

MISO	
Description	**Example Programmes**
For Economic Load Response, MISO has a similar methodology to PJM, except use the ten most recent weekdays or four most recent weekend days. Do not remove any days. The baseline will be the average hourly consumption across the days in this window. For resources using Behind the Meter Generation, the baseline will be the resource's actual metered generation over the 2-hour period before the start of the event. For Type1 Resources providing Reserves (generally non-spinning), the difference between demand 5 minutes prior to event and the average of demand 5 minutes into the event and 10 minutes into the event will be the amount of reserves provided. For Type II Resources providing Reserves (generally spinning), the difference between demand 10-seconds before the event and 10 minutes later will be considered the amount of reserves provided. Complete meter data will still be analyzed.	Economic Load Response (energy) Spinning and Non-Spinning Reserves (reserves)

CAISO	
Description	**Example Programmes**
CAISO also has a methodology similar to PJM, except use the 10 most recent days, excluding different day-types (a day-type is: weekday or weekend/ holiday) and days when there was an event or other operational anomaly, such as an outage. The calculated baseline will be the 10 day hourly average. However, the baseline may be adjusted using the “Day-Of Adjustment”. This allows the baseline to be moved closer to the actual consumption before the event. It is calculated using the average of the first three of the four hours prior to the event divided by the average load for the same hours using the last 10 weekdays. The Adjustment may not exceed plus or minus 20% of the calculated baseline.	Economic Load Response (energy) Spinning and Non-Spinning Reserves (reserves)

NYISO	
Description	**Example Programmes**
Use the five highest energy consumption levels in comparable time periods over the past 10 days, beginning 2 days prior to the days for which the load reduction is bid. The baseline is the average hourly consumption over this 5-day window. Ancillary services will simply compare demand during the event to the fixed metered demand during the interval immediately preceding event activation.	Economic Load Response (energy) ICAP (capacity) Spinning and Non-Spinning Reserves (reserves)

ISO - NE	
Description	**Example Programmes**
Use an average of the 5-minute demand intervals over the 10 preceding days. A “Symmetrical Adjustment” will be added.	Economic Load Response (energy) Forward Capacity (capacity)

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