Nordic Energy Research

The regulation of independent aggregators with a focus on compensation mechanisms

CONTENTS

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ACRONYMS

aFRR	Automatic Frequency Restoration Reserve
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CRM	Capacity remuneration mechanism
C&I	Commercial and Industrial
DA	Day-ahead
DER	Distributed energy resources
DR	Demand response
DSO	Distribution System Operator
ENA	Energy Networks Association
ESO	Electricity system operator
EV	Electric vehicle
FCR	Frequency Containment Reserve
FFR	Fast Frequency Reserve
GB	Great Britain
ID	Intraday
ISP	Imbalance Settlement Period
ISR	Imbalance Settlement Responsible
MBMA	Meter before meter after
mFRR	Manual Frequency Restoration Reserve
RES	Renewable Energy Sources
RR	Replacement reserve
ToE	Transfer of Energy
ToU	Time of Use
TSO	Transmission System Operator
USEF	Universal Smart Energy Framework

EXECUTIVE SUMMARY

The Nordic region is looking into the Electricity Market Directive (2019/944) requirements to enable demand side flexibility participation. The Directive lays out requirements and suggestions ("may") on how market participants engaged in aggregation and independent aggregation should be integrated into the electricity market, especially in Article 17. On behalf of the Electricity Market Group (EMG) under the Nordic Council of Ministers, Nordic Energy Research (NER) commissioned DNV to review how independent aggregation is (or will be) regulated in other European countries in different markets, with an emphasis on how the compensation mechanism is designed.

The objectives of this study are to:

- Present a detailed description of the aggregation models chosen for independent aggregation in selected European countries.
- Describe the experience and the view of market parties active in selected European markets regarding the independent aggregation framework.
- Analyse what lessons can be drawn for the Nordics based on the experience of the selected European countries

As part of this study, DNV has performed a desk study that has been complemented by interviews with several aggregators and with several national regulatory authorities. The selected European countries were Belgium, Finland, France, Germany, Great Britain, the Netherlands, and Switzerland.

The study describes the independent aggregator models that are found across Europe – *uncorrected, central settlement and corrected* models – and how they are implemented in the selected countries. The table below summarizes the models across the different services.

	FCR	aFRR	mFRR (& RR)	Wholesale	Capacity market
Belgium	Uncorrected	Corrected (limited applicability)	Corrected (limited applicability) Central settlement	Available from 2021: Corrected (limited applicability) Central settlement	Corrected (only applicable when customer nominates their energy schedule) Central settlement
Finland	Uncorrected (FCR-D and FFR) Central settlement (FCR-N)	N/A	Central settlement model was piloted	N/A	N/A
France	Uncorrected	Uncorrected	Corrected Central settlement	Corrected Central settlement	Corrected Central settlement
Germany	Uncorrected	Corrected	Corrected	N/A	N/A
Great Britain	Uncorrected or central settlement	Central settlement*	Central settlement*	Central settlement under discussion for future implementation	Uncorrected
Netherlands	Uncorrected	Plan to implement central settlement	Plan to implement central settlement	N/A	N/A
Switzerland	Uncorrected	Central settlement	Central settlement	N/A	N/A

Table 1. Independent aggregator models per country

Although the energy market context, as well as the timing and triggers for implementing a regulatory framework for independent aggregation, differs from country to country, many similarities on the design principles can be observed, that are also applicable to the Nordics:

- All frameworks need to comply with the Electricity market directive (also frameworks designed before the publication of the clean energy package are not conflicting with the directive[1], although possibly not covering all services – e.g. Switzerland does not support access to wholesale markets).
- All frameworks need to be consistent with the Electricity Balancing Guideline.

1. Based on DNV analysis rather than a legal assessment

- All frameworks intent to take market considerations and efficiency into account; on the one hand, attempting to create a level playing field for aggregators and on the other hand avoiding market distortions. In our analysis, Germany has prioritized the latter over the former and has not achieved a full level playing field.

Given these strong similarities in principles, we conclude that experiences and best practices from other countries are relevant to consider. At the same time, experiences in the residential sector specifically, and to a lesser extent, wholesale trading, are very limited. Although the principles are similar, there are also differences between the countries when it comes to independent aggregator framework design choices. This is summarised in the following table.

Strong similarities	Limited differences	Substantial differences
Aggregation model	Level of compensation	IT systems to facilitate independent aggregation
Use of uncorrected model	Access to wholesale markets	
Rebound	Balance responsibility	

Table 2. Differences in design choices per topic

We observe similarities or limited differences in the following aspects:

- Aggregation model: All countries studied, except Germany, have implemented or plan to implement a form of Central settlement model (France and Belgium have also implemented a corrected model).
- Use of uncorrected model: All countries use an uncorrected model for certain products, typically capacity products with a small energy component such as FCR.
- Rebound: None of the countries have taken rebound into account in relation to the balancing and/or sourcing position (i.e. compensation) yet.
- Level of compensation: All countries have implemented/plan to implement a compensation payment between the independent aggregator and supplier. Most countries set the compensation at (an approximation of) the retail tariff level (excluding taxes and network tariffs) or at the level of the sourcing costs, both leading to similar price levels.
- Access to wholesale markets: Most countries seem to struggle with implementing this aspect. Belgium has implemented it, yet there is no practical experience gained so far. France has implemented it, yet only for demand turn-down, and with some restrictions (e.g. strict requirements on baselines).
- Balance responsibility: All independent aggregators need to be/assign a BRP to be active in the wholesale market. For balancing services all independent

aggregators bear financial balance responsibility, at least for under-delivery (different regulations are observed with respect to over-delivery).

When analysing areas with limited to large differences – compensation, access to wholesale markets, balance responsibility, and IT systems – the study shows that most of the causes that have led to different design choices are not applicable to the Nordics. A key take-away is that to harmonise the Nordic approach, it is important is to agree on certain common design principles:

- Consistency with respect to the implementation of the BSP role – a common view on whether an aggregator's balancing responsibility is limited to just a financial responsibility, or should be extended to performing or outsourcing the BRP role.
- Agreement on the compensation formula.
- Agreement on the timing and principles for allowing independent aggregation access to wholesale markets.

SAMMENDRAG

De nordiske regulatorene for energi ser for tiden nærmere på kravene i elmarkedsdirektivet (2019/944) for å legge til rette for fleksibilitet på etterspørselssiden og spesielt deltakelse av aggregert forbruk og produksjon. Direktivet fastsetter blant annet krav og forslag («kan») til hvordan markedsaktører som driver med aggregering og uavhengig aggregering skal delta i elektrisitetsmarkedet, spesielt i artikkel 17. På vegne av Elmarkedsgruppen (EMG) under Nordisk Ministerråd ga Nordisk Energiforskning (NER) DNV i oppdrag å gjennomgå hvordan uavhengig aggregering er regulert i andre europeiske land, med spesiell vekt på hvordan kompensasjonsmekanismen er utformet.

Målet med denne studien er å:

- Presentere en detaljert beskrivelse av aggregeringsmodellene som er valgt for uavhengige aggregatorer i utvalgte europeiske land
- Beskrive erfaringer og synspunkt på rammeverket for uavhengige aggregatorer hos markedsaktører som er aktive i disse markedene
- Analysere hvilke lærdommer som kan trekkes for Norden basert på erfaringene fra de utvalgte landene

Som en del av denne studien har DNV gjennomført intervjuer med en rekke aggregatorer og flere europeiske regulatorer. De utvalgte landene er Belgia, Finland, Frankrike, Tyskland, Storbritannia, Nederland og Sveits.

Studien beskriver de ulike modellene for uavhengige aggregatorer som finnes over hele Europa – korrigert (uncorrected), sentral avregning (central settlement) og korrigert (corrected) – og hvordan de er innført i forskjellige land. Tabellen nedenfor oppsummerer modellene som benyttes for de forskjellige tjenestene.

	FCR	aFRR	mFRR (& RR)	Engros-markedet	Kapasitets-markeder
Belgia	Ukorrigert	Korrigert (begrenset omfang)	Korrigert (begrenset omfang) Sentral avregning	Korrigert (begrenset omfang) Sentral avregning	Korrigert (begrenset omfang) Sentral avregning
Finland	Ukorrigert (FCR-D og FFR) Sentral avregning (FCR-N)	N/A	Sentral avregning er testet i pilot	N/A	N/A
Frankrike	Ukorrigert	Ukorrigert	Korrigert Sentral avregning	Korrigert Sentral avregning	Korrigert Sentral avregning
Tyskland	Ukorrigert	Korrigert	Korrigert	N/A	N/A
Storbritannia	Ukorrigert eller sentral avregning	Sentral avregning	Sentral avregning	Sentral avregning vurderes	Ukorrigert
Nederland	Ukorrigert	Planlegger sentral avregning	Planlegger sentral avregning	N/A	N/A
Sveits	Ukorrigert	Sentral avregning	Sentral avregning	N/A	N/A

Tabell 1. Modeller for aggregering i ulike land

Selv om både konteksten, tidspunktet og utløsende faktorer for å utvikle et regulatorisk rammeverk for uavhengig aggregering er forskjellig fra land til land, er det mange prinsipielle likheter. Dette gjelder også for Norden:

- Alle rammeverk må være i samsvar med elmarkedsdirektivet (også rammeverk utformet før publiseringen av Ren Energi pakken er i tråd med direktivet[2], men de dekker ikke nødvendigvis alle tjenester – for eksempel støtter ikke Sveits tilgang til engrosmarkeder).
- Alle rammeverk må være i samsvar med retningslinjen for elektrisitetsbalansering (EBGL).
- Alle rammeverk tar hensyn til markedet og til effektivitet; De skal på den ene siden skape like konkurransevilkår for aggregatorer og på den andre siden unngå markedsvridning mellom aggregatorer og tradisjonelle kraftleverandører. I vår analyse har Tyskland prioritert sistnevnte fremfor førstnevnte, og har ikke oppnådd fullstendig like konkurransevilkår.

Gitt disse sterke prinsipielle likhetene, konkluderer vi med at erfaringer og beste

2. Basert på DNVs analyse, ikke en juridisk vurdering.

praksis fra andre land er relevante for Norden. Samtidig er erfaringene svært begrensede, spesielt innenfor alminnelig forsyning, og i noen grad innenfor engroshandel.

Selv om prinsippene er like, er det også forskjeller mellom landene når det gjelder design av rammeverket for uavhengige aggregatorer. Dette er oppsummert i tabellen nedenfor.

Sterke likhetstrekk	Begrensede forskjeller	Store forskjeller
Aggregator-modell	Nivå på kompensasjon	System og rutiner for å legge til rette for uavhengig aggregatorer
Bruk av ukorrigert modell	Tilgang til engrosmarkeder	
Rebound-effekt	Balanseansvar	

Table 2. Likhetstrekk og forskjeller i designvalg

Vi observerer likheter mindre forskjeller for disse aspektene:

- Modell for aggregering: Alle land som er studert, unntatt Tyskland, har innført eller planlegger å innføre en form for sentrale oppgjør. Frankrike og Belgia har også innført en korrigert modell.
- Bruk av ukorrigert modell: Alle land bruker en ukorrigert modell for noen produkter, typisk kapasitetsprodukter med en liten energikomponent som FCR.
- Rebound-effekt: Ingen av landene har tatt hensyn til rebound-effekten i forhold til ubalanser og/eller innkjøp av energi (dvs. kompensasjon) ennå.
- Kompensasjonsnivå: Alle land har eller planlegger å innføre en kompensasjonsbetaling mellom den uavhengige aggregatoren og leverandøren. De fleste land setter kompensasjonen til (en tilnærming til) nivået for priser til sluttbrukere (uten nettleie og avgifter) eller til nivået for innkjøpskostnadene, som begge fører til om lag samme prisnivå.
- Tilgang til engrosmarkedet: Dette synes å skape store utfordringer i de fleste land. Belgia har innført dette, men har enda ingen praktisk erfaring. Frankrike har også innført dette, men bare for reduksjoner i forbruk, og da med noen vesentlige restriksjoner (for eksempel strenge krav til utforming og formidling av baseline).
- Balanseansvar: Alle uavhengige aggregatorer må være balansevarlig (BRP), alternativt kjøpe tjenesten fra noen andre, for å være aktive i engrosmarkedet. For balansetjenester har alle uavhengige aggregatorer økonomisk balanseansvar, i det minste om det leveres for lite. Om det leveres for mye finnes det ulike regler.

Ser vi på tema med mindre til større forskjeller – kompensasjon, tilgang til engrosmarkedet, balanseansvar og IT-systemer – viser studien at de fleste årsakene som har ført til ulike designvalg ikke er relevante for Norden. Med tanke på nordisk harmonisering, ser det ut til å være viktigere å bli enige om felles prinsipper for design:

- Konsistens med hensyn til innføring av BSP-rollen – et felles syn på om aggregatorenes balanseansvar er begrenset til økonomisk ansvar, eller bør utvides til å utføre BRP-rollen selv (alternativt kjøpe tjenesten)
- Enighet om formel for kompensasjon
- Enighet om tidspunkt og prinsipper for å tillate tilgang til engrosmarkedet for uavhengig aggregatorer.

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Andrea Stengel at Nordic Energy Research was the coordinator of the project.

Team at DNV

Aurora Sáez Armenteros, *Project manager, Senior consultant*, aurora.saez@dnv.com

Hans de Heer, *Principal consultant*, hans.deheer@dnv.com

Jørgen Bjørndalen, *Principal consultant,* jorgen.bjorndalen@dnv.com

Lars Johan Karlbom, *Senior consultant*, lars.johan.karlbom@dnv.com

Steering group

The study was supervised and guided by the representatives from the ministries: Tatu Pahkala and Elina Hautakangas at the Ministry of Economic Affairs and Employment in Finland, Johnny Lindstrom at the Government of Åland; Pär Lyden and Fredrik Norlund at the Ministry of Infrastructure, Mia Frydensberg Ravn, Peter Olsen and Peter Sølvsten at the Danish Energy Agency, Ane Hammer Langhelle, Laila Berge and Kaja Malene Remme at the Norwegian Ministry of Petroleum and Energy.

Stakeholder input

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The individuals and organizations that contributed to this study are not responsible for any opinions or judgements contained herein.

Contact

Comments and questions are welcome and should be addressed to: Aurora Sáez Armenteros, e-mail: aurora.saez@dnv.com

For inquiries regarding the presentation of results or distribution of the report, please contact Nordic Energy Research.

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Fiskebäckskil, Sweden

INTRODUCTION

Context

The Nordic region is looking into the Electricity Market Directive (2019/944) requirements to enable demand side participation. The Directive also lays out requirements and suggestions ("may") on how market participants engaged in aggregation and independent aggregation should be integrated into the electricity market, especially in Article 17.

On behalf of the Electricity Market Group (EMG), Nordic Energy Research (NER) commissioned DNV to review how independent aggregation is regulated in other European countries in different markets, with an emphasis on how the compensation mechanism is designed.

EMG is a working group under the Nordic Council of Ministers and consists of experts from the Ministries and energy authorities of Denmark, Finland, Norway and Sweden. Nordic Energy Research (NER) is an intergovernmental institution for cooperative energy research and policy development under the auspices of the Nordic Council of Ministers (NCM). NER facilitates and funds research, development and analysis to promote a sustainable future and contribute to Nordic policy making and cooperation within the field of energy. The Nordic Council of Ministers is funding this project.

Purpose of this study

The objectives of this study are to:

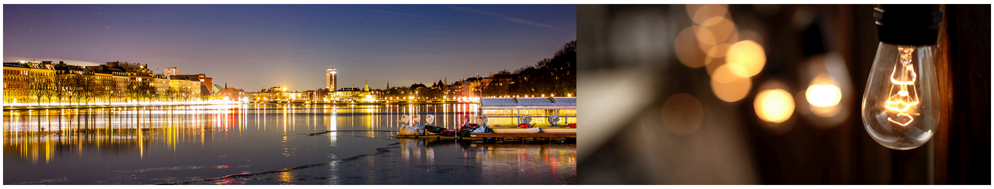
- Present a detailed description of the aggregation models chosen for independent aggregators in selected European countries.
- Describe the experience and the view of market parties active in selected European markets regarding the independent aggregation framework.
- Analyse what lessons can be drawn for the Nordics based on the experience of the selected European countries.

As part of this study, DNV has performed a desk study that has been complemented by interviews with several aggregators and with several European regulators.

Structure of this report

This report is structured as follows:

- Section 1 describes existing aggregator models and key concepts that define them as per the USEF framework.
- Section 2 describes the experience of selected European countries that have implemented or are implementing independent aggregator frameworks, including both regulatory and practical experience from the aggregator's perspective. This section also describes the general energy context in each selected country.
- Section 3 describes the lessons learnt for the Nordic independent aggregation framework based on the context of the analysed countries, as well as regulator and aggregator feedback.
- Section 4 presents the conclusions and states the aspects where the European independent aggregation implementation have the most differences and commonalities.



Copenhagen, Denmark

1. OVERVIEW OF AGGREGATOR MODELS

In this section, we first present the key concepts that characterise an aggregator model. This is followed by the description of the different aggregator implementation models identified by the USEF framework. The purpose of this section is to set the basis for the terminology used throughout the report.

1.1 Key concepts

The USEF foundation describes four key attributes of the aggregator-supplier relationship that are essential to describe an aggregator model. These concepts are: contractual relationship, balance responsibility, sourcing position and information exchange.

Contractual relationship
This concept refers to the contractual relationship between aggregator and the supplier, or between aggregator and the Balance Responsible Party of the supplier (BRP_{sup}). The contractual relationship is key to identifying whether the aggregator model can be considered independent. The aggregator is performing independent aggregation for a certain customer when there is no contractual relationship between the aggregator and this customer's supplier or BRP_{sup}.

Balance responsibility
The balance responsibility concept defines the balance responsibility requirements for the aggregator, often in relation to the supplier. The aggregator, as an active market participant, can cause imbalances in the system with their actions, therefore the aggregator model should define who is responsible for the imbalances and how it is arranged.

Sourcing position
The sourcing position of a supplier represents the balance between the energy sold to retail customers and energy sourced in the energy market. When an aggregator activates flexibility from a customer, the sourcing position of the supplier will be impacted, by either preventing sourced energy to be sold or by triggering energy to be sold that has not been sourced. A similar concept applies to the aggregator role; to be able to sell energy (especially on wholesale markets), the aggregator must source it (dispaching a flexible asset at a customer will, by itsef, not change the Aggregator's position). The customer's supplier is the only logical party to source this

energy from. The act of sourcing and selling energy between aggregator and supplier is the so-called 'transfer of energy' (ToE).[3] The aggregator model should define the mechanism to correct the sourcing position, its price, and the settlement mechanism.

Please note that supplier compensation / ToE, depending on how it is implemented, often corrects both the balancing position and the open sourcing position at the same time. Since the balancing position relates to the BRP role and the sourcing position to the Supplier role, USEF treats these aspects separately, even though the Supplier and BRP role are often combined into a single market participant.

Information exchange and confidentiality
This aspect covers the requirement for aggregators regarding information exchange with other market parties such as BRP, supplier, imbalance settlement responsible (ISR), system operators, amongst others. Next to information exchange, confidentiality is a key aspect since it can have an impact on establishing a level playing field.

1.2 Non-Independent aggregator models

Although this study focuses on independent aggregator models, it is relevant to present the overview of non-independent aggregator models given that they are already present in the European landscape and are an alternative to independent aggregation.

Integrated model: The supplier and the aggregator roles are combined within a single market party.

Broker model: The aggregator is in charge of operating the flexibility with the supplier's portfolio and the supplier-aggregator relationship is governed by an agreement. The aggregators do not perform the BRP role itself, but agree bilaterally with the supplier's BRP how any imbalances caused by the aggregator are compensated.

Contractual model: The aggregator and the supplier are two different market parties with their own BRP. The aggregator holds balance responsibility during flexibility activation, potentially limited to flexible asset(s), and the supplier remains balance responsible for the connection. After a flexibility activation, supplier and aggregator trade the sourced/sold energy at the price specified in their contract.

3. Note that the term of transfer of energy is not used in France as established inappropriate by a decision from the upper court, thus leading to this notion being abandoned in French law. Instead, the French law uses a financial compensation.

	Contractual relationship	Balance responsibility	Sourcing position	Information exchange & confidentiality
Integrated	Both roles performed by single market party, therefore there is no contract needed.	There is only one BRP, and it represents supplier and aggregator.	This aspect is not applicable because they are a combined market party.	This aspect is not applicable because both roles are combined.
Broker	Bilateral contract between aggregator and supplier that also covers the impact of imbalances.	There is only one BRP which is the supplier's BRP.	This aspect is handled bilaterally. There could be an impact on the sourcing position, financial compensation (can be both ways) are agreed in the contract.	This is arranged bilaterally between supplier and aggregator. The minimum information exchange should be the volumes that were activated by the aggregator.
Contractual	Contract between the aggregator and supplier. The contract should specify information exchange, sourcing mechanism and price.	There are two BRPs, the supplier's and the aggregator's. The aggregator's BRP only has balance responsibility of the flexible assets during activation, for the activated volume.	Aggregator and supplier trade the sourced/sold energy bilaterally, ex-post activation, using the terms in their contract.	This is arranged bilaterally between supplier and aggregator. The minimum information exchange should be the volumes that were activated by the aggregator.

Table 3. Summary of non-independent aggregator models key aspects

1.3 Independent aggregator models

As per the USEF aggregator implementation model classification, the models that do not require a contractual relationship between aggregator and supplier are the *uncorrected*, the *central settlement* and the *corrected* model.

1.3.1 Uncorrected model

Balance responsibility
When applying the uncorrected model, the aggregator does not hold balance responsibility or financial responsibility for the imbalances caused in the system when activating flexibility. The perimeter (i.e. portfolio) of the supplier's BRP might be in imbalance after flexibility activation and the imbalance is not corrected by the system operator or imbalance settlement responsible (ISR). When this model is applied in balancing or adequacy services, the flexibility activation will most likely help the system balance, which will then count as passive imbalance contribution by the supplier's BRP. Due to the passive balance contribution, the BRP might be

remunerated as part of the imbalance settlement mechanism.[4]

Sourcing position
The sourcing position is not directly balanced by this mechanism. However, if the passive balance contribution is remunerated through the imbalance settlement mechanism, the supplier's BRP will be remunerated implicitly for the energy sourced, at the imbalance price.

Information exchange & confidentiality
There is no need for any information exchange apart from the information exchange required to participate in markets or services. The supplier does not receive any communication that discloses the presence of an aggregator. However, that does not remove the possibility of the supplier finding out through analysing the behaviour of their customers via the metering data.

1.3.2 Central settlement model

Balance responsibility
When applying this model, the aggregator is balance responsible or financially responsible for the imbalances that they may cause during flexibility activation of their flexible assets. Next to being responsible during the flexibility activation, some models may also consider that the aggregator is also responsible for the rebound effect[5] caused by the flexibility activation, which is typically outside the activation window.

Since the flexibility activation will be seen as an imbalance in the perimeter of the supplier's BRP, a central entity (such as a system operator or ISR) corrects the supplier's BRP perimeter by deducting or adding the deviation caused by the aggregator. This is also known as imbalance adjustment.

Sourcing position
The central settlement model facilitates the transfer of energy through a central entity, system operator or ISR. The price level of the transfer of energy is regulated by the National Regulatory Authority. Under this arrangement, the aggregator would pay for the sourced energy, at the ToE price, to the central entity and the central entity would transfer it to the supplier. In case of load enhancement or generation reduction, both energy and payment will flow in the opposite direction.

When the sourced energy is not compensated by the aggregator but by society or other entities that are benefitting by the flexibility activation, the central settlement model becomes the **net benefit model**.

Information exchange & confidentiality
The central entity determines the activated volume per ISP for each aggregator, often based on information provided by the aggregator, such as (sub) meter data and activated assets / customers. The central entity does not disclose the customers of the aggregator, nor the aggregator to the supplier, as this can impact the level playing field. The supplier is informed about the total amount of flexibility (energy) that has been activated within its portfolio, per ISP.

4. This is only applicable when the imbalance settlement mechanism is based on single imbalance pricing.
5. For rebound effect we use the definition of the phenomenon that the load reduction (or increase) triggered by a demand response event, is compensated partly or fully outside the activation period or by other resources.

1.3.3 Corrected model

Balance responsibility
Like for the central settlement model, when applying the corrected model, the aggregator is balance responsible or financially responsible for the imbalances that they may cause during flexibility activation of their flexible assets. Next to being responsible during the flexibility activation, some models may also consider that the aggregator is also responsible for the rebound effect[6] caused due to flexibility activation, which is typically outside the activation window.

There are two variations to this model:

- Type A: The meter data company (or other central entity) corrects the meter data by the flexibility amount that was activated during flexibility delivery. In this case the perimeter of the supplier's BRP does not need to be corrected because the imbalance settlement will be performed with the corrected metering data.
- Type B: A central entity communicates the activated flexibility volumes to the supplier's BRP, and the supplier bills the customer as if no flexibility was activated. In this case, a central entity corrects the perimeter of the supplier's BRP based on the activated flexibility. Depending on the implementation, this model can be very similar to central settlement.

For both types, the perimeters of the Aggregator's BRP are corrected by the central entity, if the aggregator holds formal balance responsibility.

Sourcing position
The principle of this model is that the transfer of energy goes through the customer. The supplier bills the customer as if the flexibility was not activated and the aggregator compensates the customer to cover for the energy that was billed but not consumed (i.e. transfer of energy) at the retail price. However, there are differences when applying the different sub-models:

- Type A: The supplier bills the customer using the corrected meter values.
- Type B: The supplier bills the customer using the original meter values and a different specification with the activated flexibility volume.

For applying this model, the calculation of taxes and network tariffs should be based on the actual consumption, not on the corrected meter values.

Information exchange
The information exchange requirements also vary per sub-model:

- Type A: The supplier does not receive any information on flexibility activations or the fact that there is an aggregator active at its customer's site. This type is the one that preserves the confidentiality the most, as it cannot even be detected by analysing meter readings.
- Type B: A central entity informs the supplier on the volume of activated flexibility per customer, per ISP. The identity of the aggregator does not need to be disclosed, but it does reveal which customers have flexibility that can be valorised, which can be considered commercially sensitive.

6. For the rebound effect we use the definition of the phenomenon that the load reduction (or increase) triggered by a demand response event, is compensated partly or fully outside the activation period.


Helsinki, Finland

2. INTERNATIONAL EXPERIENCE

In this chapter we present the experience of seven European countries – Belgium, Finland, France, Germany, Great Britain, Netherlands, and Switzerland – on the implementation of the (independent) aggregator framework. First, we present the general energy landscape context of the different countries. Then we present the model choices, aggregator models and the details of it, per sector. The sector division is relevant because there are fundamental differences in demand response characteristics and progress on aggregator frameworks between sectors. Subsequently, we lay out the considerations of the country regulators when designing the regulatory framework. Lastly, we touch upon the deployment experience of the aggregator framework by aggregators, what are the barriers they perceive, their incentives and feasible business models, among other aspects.

The selected countries were chosen on the basis of having more advanced regulation for independent aggregators and/or relatively significant demand response participation in services and markets.

2.1 General context

Certain elements of the energy landscape context of each country are key to understanding the aggregator implementation choices that are set by regulation. As such, this context will serve to identify the lessons that can be applied to the Nordic countries in later chapters.

2.1.1 Belgium

2.1.1.1 Supply and Generation

- Generation mix: in Belgium the generation mix is dominated by nuclear and natural gas, covering nearly 70% of the electricity production. Intermittent renewables have a share of around 20% of the energy mix.

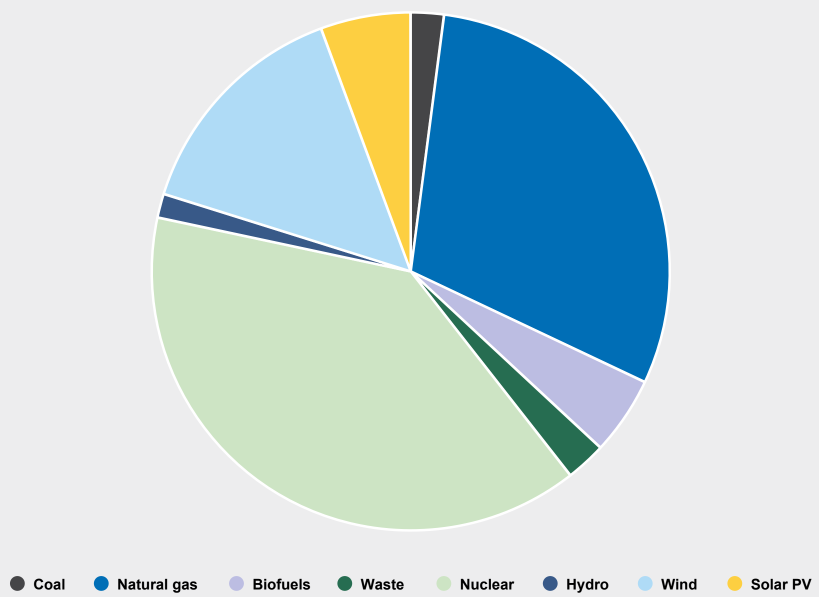


Figure 1. Generation mix 2020 – Belgium[7]

- Retail competitive landscape: there are 36 suppliers active in Flanders whereas in Wallonia there are 14. The switching rate of energy supplier is relatively high in Belgium, it is at 18,95% for households and at 21,6% for non-households.
- Energy tariffs: Retail tariffs for domestic customers are either flat rate or time of use (generally day/night tariff). Dynamic tariffs are not yet available for domestic customers. The roll-out of smart meters is expected to facilitate the adoption of dynamic tariffs, however progress has been slow. For industrial customers, dynamic supply tariffs are available but are not very common. In a typical retail tariff, the energy component represents 23% of the bill whereas taxes take nearly 50%.

7. https://www.iea.org/

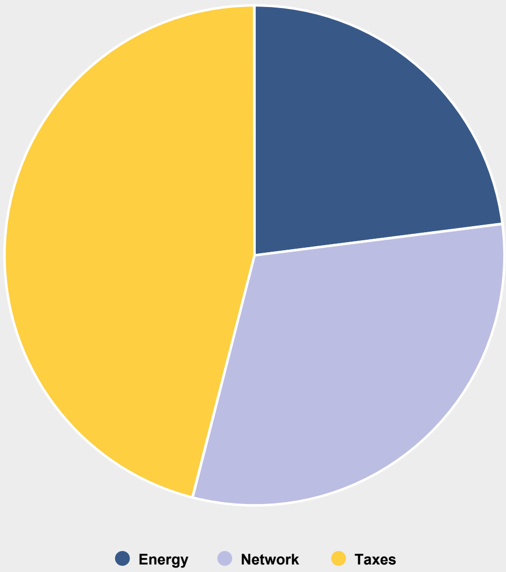


Figure 2. Electricity bill breakdown – Belgium[8]

2.1.1.2 Network status

- Network investments, trends and digitalisation: The Belgian network and communication exchange is becoming centralised and digital, and it's heading towards customer centricity. The Belgian energy market switched to a new central platform for data traffic in 2021.[9] Elia has released a white paper on a consumer-centric electricity system. The paper suggests that the current market design limits the rapid deployment of consumer-oriented services. The paper proposes two changes to make the system consumer centric: the development of the 'exchange of energy blocks'[10] for consumers and the introduction of a robust price signal.[11]
- Smart meter roll-out: In 2020, Belgium had a smart meter penetration rate of 3.3%.[12] For the time being, the DNOs are installing smart meters only when they need to replace an old meter or where a customer specifically requests one. However, a mass rollout at the national level for all customers on the low-voltage grid is expected.[13] Fluvius envisions reaching 80% rate of the Flemish households by 2024.[14]

8. https://www.creg.be/sites/default/files/assets/Prices/Kerncijfers/Kerncijfers2020.pdf
9. https://www.atrias.be/
10. 'Exchange of Energy Blocks' hub is a concept in which the exchange of energy would occur on a fifteen-minute basis between consumers and other market parties.
11. https://www.elia.be/en/news/press-releases/2021/06/20210618-elia-group-publishes-white-paper-on-a-consumer-centric-and-sustainable-electricity-system
12. https://cdn.eurelectric.org/media/5089/dso-facts-and-figures-11122020-compressed-2020-030-0721-01-e-h-57999D1D.pdf
13. https://www.energyprice.be/blog/smart-meter/
14. https://www.smart-energy.com/regional-news/europe-uk/fluvius-initiates-4-3-million-smart-meter-rollout-in-belgium/

2.1.1.3 Regulatory context

- Network tariffs: Grid users under 56kVA are able to choose between flat and peak/off-peak (day/night) tariffs as distribution tariff and they are mostly based on energy volume. From 2022, the network tariffs will also incorporate a capacity component.[15]
- Regulatory framework for demand-side participation: DSR can participate in balancing services, adequacy services and wholesale. The participation on constraint management will soon be enabled by the iCAROS project.[16]

15. USEF Flexibility deployment in Europe.
16. New network tariffs VREG

2.1.2 Finland

2.1.2.1 Supply and Generation

- Generation mix: Over 50% of the electricity is generated with nuclear and hydro power. Fossil fuels have a 13% share and wind energy has a 12% share.

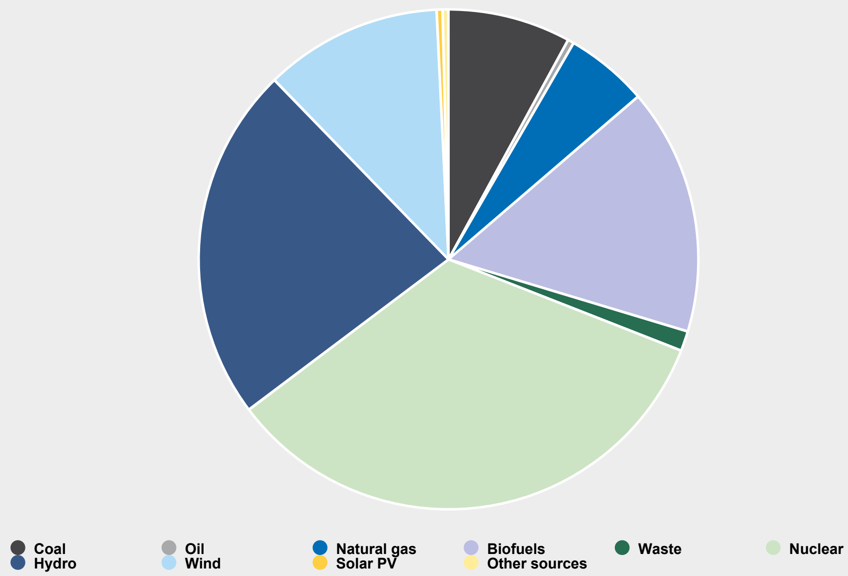


Figure 3. Generation mix 2020 – Finland[17]

- Retail competitive landscape: There are approximately 63 electricity suppliers (retailers). The three largest retailers have a 45% market share and there is a moderate market concentration (~900 HHI score). The market has been increasing in concentration in the past years according to the Finnish Energy Authority. Switching rate 15.6%, approximately 400,000 switches occur every year.[18]
- Energy tariffs: Time-of-use and seasonal electricity tariffs are available. Dynamic (market price exchange) tariffs are available. However, 52% of the households choose fixed price retail contracts whereas the share of dynamic contracts is 8%. The energy component of the electricity bill represents about one third of the total, same as taxes and network tariffs.[19] [20]

17. https://www.iea.org/
18. https://energiavirasto.fi/documents/11120570/13026619/National+Report+2021+Finland+2490-480-2021.pdf/76654dd9-d77f-afbf-529e-01a1db278e92/National+Report+2021+Finland+2490-480-2021.pdf?t=1626089398976
19. https://energiavirasto.fi/documents/11120570/13026619/National+Report+2021+Finland+2490-480-2021.pdf/76654dd9-d77f-afbf-529e-01a1db278e92/National+Report+2021+Finland+2490-480-2021.pdf?t=1626089398976
20. Time-of-day Electricity and Seasonal Electricity Helen

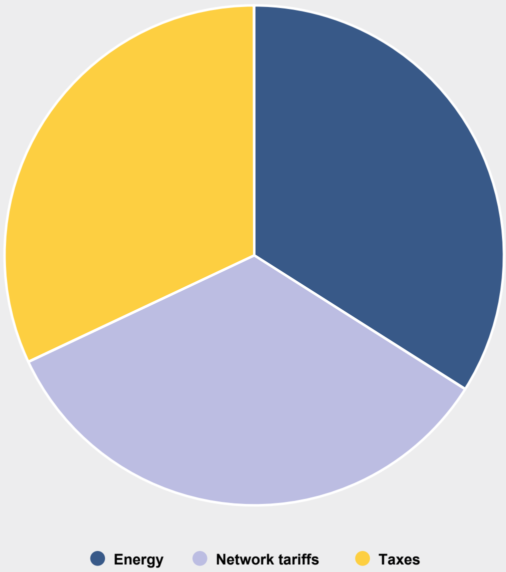


Figure 4. Electricity bill breakdown – Finland[21]

2.1.2.2 Network status

- Network investments, trends and digitalisation: Finland is part of the synchronous inter-Nordic system. It has interconnections with Russia, Estonia and Sweden, however, it is the least interconnected Nordic country.[22]
- Smart meter roll-out: The roll-out of smart meters is complete (with second generation now in roll-out), offering the possibility to make hourly energy prices available to customers.[23]

2.1.2.3 Regulatory context

- Network tariffs: Transmission and distribution tariffs in Finland are either flat rate or peak/off-peak tariffs, largely based on consumed energy volume. Most DSOs only offer peak/off-peak tariffs but there are others also offering tariffs based on peak capacity. It is also possible to choose a 'night tariff' or 'night control.[24]
- Regulatory framework for demand-side participation: DSR is allowed to participate in balancing services (FCR-N, FCR-D, FFR, aFRR, and mFRR), strategic reserves, and congestion management at transmission level and wholesale markets. In the latter, DSR is only allowed to participate with the BRP's portfolio, in an implicit way.

21. https://energiavirasto.fi/documents/11120570/13026619/National+Report+2021+Finland+2490-480-2021.pdf/76654dd9-d77f-afbf-529e-01a1db278e92/National+Report+2021+Finland+2490-480-2021.pdf?t=1626089398976
22. https://energiavirasto.fi/documents/11120570/13026619/National+Report+2021+Finland+2490-480-2021.pdf/76654dd9-d77f-afbf-529e-01a1db278e92/National+Report+2021+Finland+2490-480-2021.pdf?t=1626089398976
23. Connecting the dots: Distribution grid investment to power the energy transition - Eurelectric – Powering People
24. USEF, Flexibility deployment in Europe, 2021

2.1.3 France

2.1.3.1 Supply and Generation

- Generation mix: The French generation mix is dominated by nuclear power, which covers two thirds of the total. Intermittent renewable penetration has a share of around 10%, and fossil fuel share is below 10%.

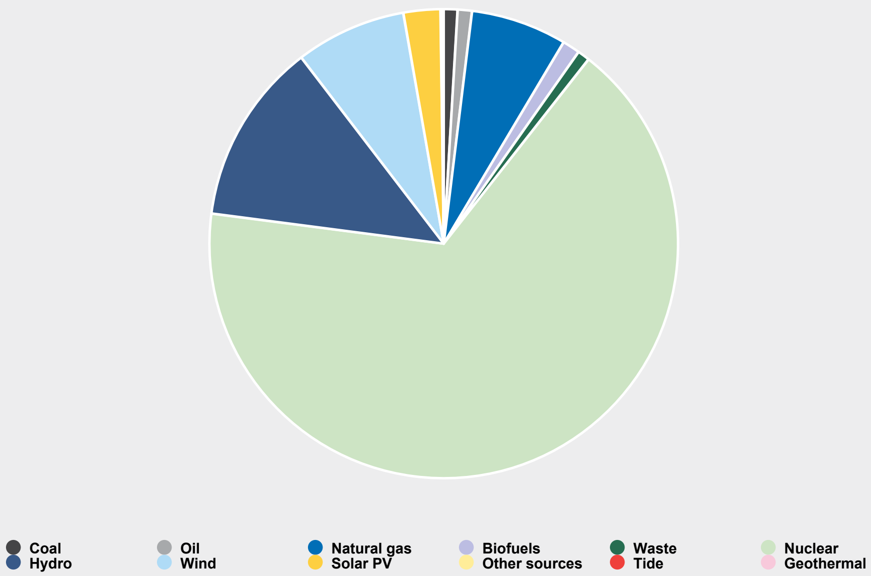


Figure 5. Generation mix 2020 – France[25]

- Retail competitive landscape: There are 46 suppliers,[26] with EDF having 70% of the market share. The switching rate has been increasing from 1% to 3% per year between 2014 to 2020, the switching rate in 2018 was 10%. The French market is highly concentrated, with an HHI index of 5000, according to CRE.[27]
- Energy tariffs: In France, households can choose between regulated or non-regulated tariffs. Regulated tariffs, only applicable for EDF, are the most common choice. There are three available regulated tariffs: base, peak/off-peak and dynamic. 'Tempo' is the most dynamic of the regulated tariffs, with six different tariffs, depending on the day (blue, white and red) and peak and off-peak hours, whereas Tarif Bleu (the peak/off-peak tariff) is the most popular among residential customers. Dynamic supply tariffs are more common among large industrial customers.[28] In a typical customer electricity bill, the energy

25. https://www.iea.org/
26. https://www.fournisseur-energie.com/liste-fournisseurs-electricite/
27. https://iea.blob.core.windows.net/assets/7b3b4b9d-6db3-4dcf-a0a5-a9993d7dd1d6/France2021.pdf
28. https://smarten.eu/wp-content/uploads/2020/12/the_smarten_map_2020_DIGITAL.pdf, https://www.fournisseur-energie.com/liste-fournisseurs-

component, taxes and network tariffs represent one third each approximately.

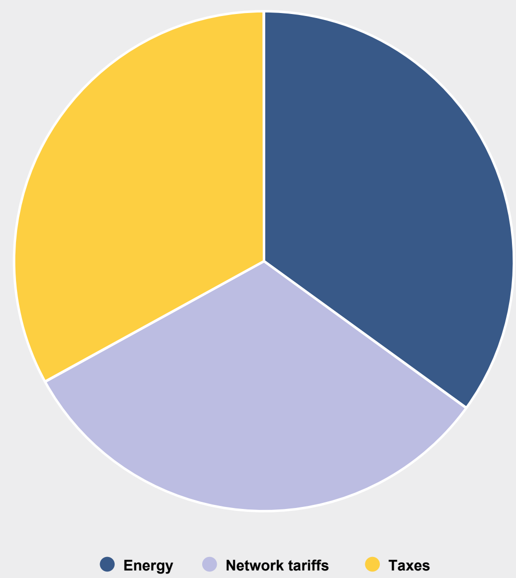


Figure 6. Electricity bill breakdown – France[29]

2.1.3.2 Network status

- Network investments, trends and digitalisation: France is a highly electrified country and is interconnected with 6 countries (Great Britain, Belgium, Germany, Spain, Italy and Switzerland). Due to the penetration of renewables, constraints are expected in the transmission grid, which will be solved via infrastructure, not flexibility solutions.[30] On the other hand, on the distribution grid, Enedis (DSO covering 95% of French connections) released a roadmap to use local flexibilities to optimise planning and operation on the distribution network.[31]
- Smart meter roll-out: Although the roll-out has had good progress it has not been completed yet. In 2020, France had a smart meter penetration rate of 76.4%.[32]

2.1.3.3 Regulatory context

- Network tariffs: Distributed tariffs for medium voltage are time-of-use (ToU) and consumers have the choice between static ToU and mobile tariffs (with the

electricite/, https://en.selectra.info/energy-france/suppliers/edf/tarif-bleu
29. https://prix-elec.com/tarifs/electricite/decomposition
30. https://assets.rte-france.com/prod/public/2020-07/Sch%C3%A9ma%20d%C3%A9cennal%20de%20d%C3%A9veloppement%20de%20r%C3%A9seau%202019%20-%20Synth%C3%A8se%20%E2%80%93%20English%20version.pdf
31. https://www.enedis.fr/sites/default/files/documents/pdf/roadmap-tranformation-network-planning-methods-integration-flexibilities.PDF
32. https://cdn.eurelectric.org/media/5089/dso-facts-and-figures-11122020-compressed-2020-030-0721-01-e-h-57999D1D.pdf

peak hours communicated a day-ahead). For low voltage, the ToU tariff is based on 4 time periods.[33]

- Regulatory framework for demand-side participation: In France, DSR can participate in balancing, adequacy, constraint management, DSO constraint management (at trial stage) and wholesale. Demand response is allowed to participate in the day-ahead and intraday market since 2014. Since then, the French regulatory framework has been developing, which makes it one of the most advanced in Europe. Moreover, France allows customers that are not half-hourly settled to offer their flexibility, which is not the case (and not foreseen) in many countries.

33. USEF, Flexibility deployment in Europe, 2021

2.1.4 Germany

2.1.4.1 Supply and Generation

- Generation mix: Over 50% of the German generation mix is dominated by fossil fuels, coal and natural gas. Intermittent renewable generation has around 30% share.

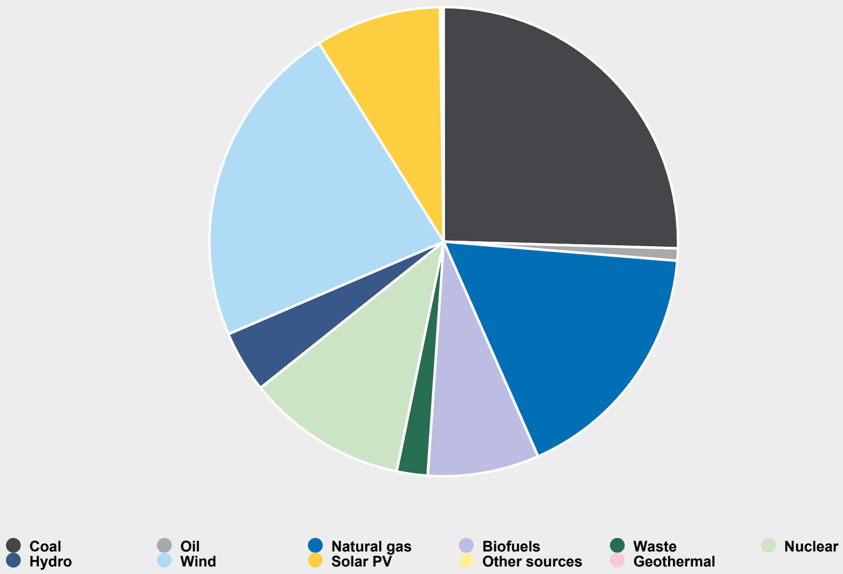


Figure 7. Generation mix 2020 – Germany[34]

- Retail competitive landscape: 138 different electricity suppliers (retailers). According to BNetzA, 66% of residential customers are supplied by local default supplier. Switching rate for customers with an annual consumption of more than 10 MWh is 11.7%.[35]
- Energy tariffs: On/off peak tariffs are available as well as dynamic tariffs, however these are barely used due to the lack of smart metering infrastructure. Regarding the electricity bill breakdown, only 24% of the bill corresponds to energy whereas taxes represent over half of it.[36]

34. https://www.iea.org/
35. Monitoring report 2020 –Key findings and summary (bundesnetzagentur.de)
36. https://smarten.eu/wp-content/uploads/2019/12/the_smarten_map_2019.pdf

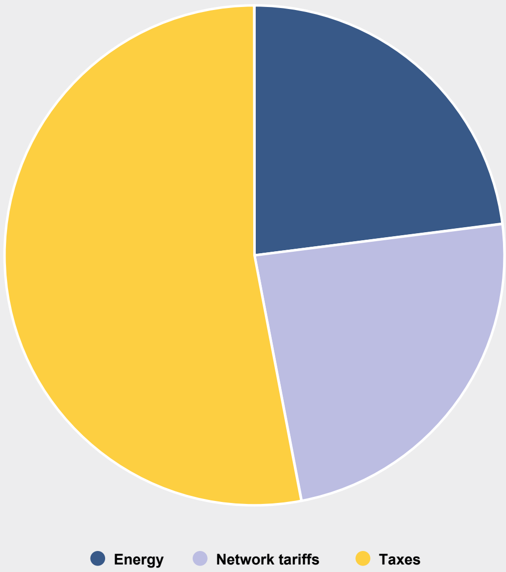


Figure 8. Electricity bill breakdown – Germany[37]

2.1.4.2 Network status

- Network investments, trends and digitalisation: In Germany there are 4 TSOs and approximately 880 DSOs. The transmission grid is expected to have congestion problems in the coming years due to renewable penetration. The German TSOs will implement ad-hoc measures, such as grid boosters, to prevent large redispatch volumes from 2025.[38] There are large investments foreseen in the distribution grid, particularly in rural areas to facilitate the integration of small-scale PV. Solving congestion problems through market-based solutions is not supported by regulation, instead, they are implementing 'redispatch 2.0' which will allow system operators to control assets over 100 kW.
- Smart meter roll-out: The German smart meter roll-out is not expected to be complete until 2030. In 2020 the penetration rate was 17%.[39]

2.1.4.3 Regulatory context

- Network tariffs: Network charges are predominantly based on consumed energy volumes. There is a maximum capacity charge but only for connections above 100 000 kWh. Moreover, industrial loads are highly incentivised to maintain a baseload consumption throughout the year.
- Regulatory framework for demand-side participation: In contrast to the wide penetration of distributed assets, the contribution of flexibility to balance the German energy market and the transmission and distribution networks is somewhat limited due to regulatory barriers. DSR can participate in balancing services and wholesale markets, but the latter only within the BRP portfolio. The

37. Monitoring report 2020 –Key findings and summary (bundesnetzagentur.de)
38. https://www.netzentwicklungsplan.de/sites/default/files/paragraphs-files/Standard_presentation_GDP_2030_V2019_2nd_draft.pdf
39. Connecting the dots: Distribution grid investment to power the energy transition - Eurelectric – Powering People

strategic reserve is open for DSR participation in theory, but the product design makes this practically impossible.

2.1.5 Great Britain

2.1.5.1 Supply and Generation

- Generation mix: In the UK, gas and nuclear energy cover just above 50% of the generation. Wind and solar energy share is around 25%.

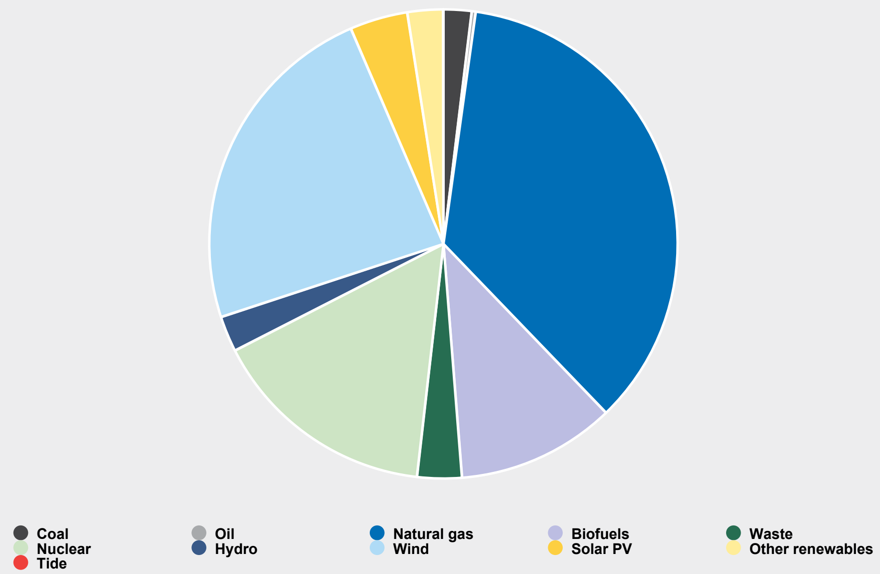


Figure 9. Generation mix 2020 – UK[40]

- Retail competitive landscape: There are 40 electricity suppliers, of which 28 are active in the domestic sector, according to the numbers at the beginning of 2021. According to BEISS, the top 3 suppliers have around 40% of the market share and the market concentration is moderate (HHI is around 1000).[41] Regarding switch rate, in 2020, 6 million customers switched supplier which represents around 20% of the total.[42]
- Energy tariffs: Residential customers who have half-hourly meters can choose a ToU tariff, however those contracts are not common and there is little choice compared to some other European countries. Only one retail tariff in GB offers a dynamic setting. Dynamic tariffs are also available to industrial customers. The breakdown of the energy bill is roughly 32% energy, 42% levies, and 23% network tariffs:[43]

40. https://www.iea.org/
41. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1021789/Competition_in_UK_Electricity_Markets_2020.pdf
42. https://www.energy-uk.org.uk/media-and-campaigns/press-releases/497-2021/7792-6-million-customers-switch-electricity-supplier-in-2020.html
43. http://powerresponsive.com/wp-content/uploads/2021/04/NG_MEUC-book-2021.pdf

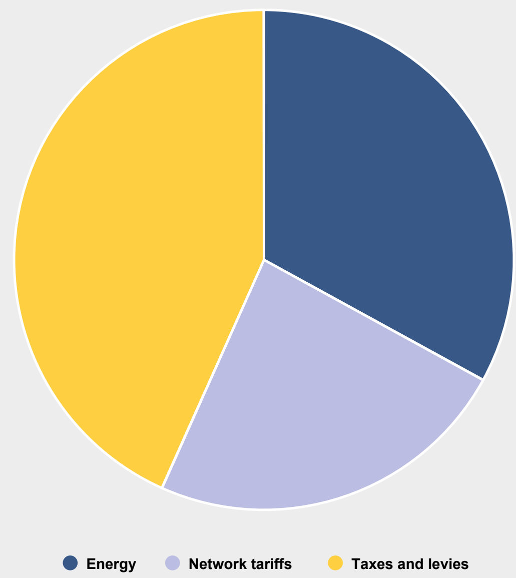


Figure 10. Electricity bill breakdown 2020 – UK[44]

2.1.5.2 Network status

- Network investments, trends and digitalisation: Ofgem has published a Smart Systems and Flexibility Plan in 2021 that aims to facilitate flexibility from consumers, remove barriers of flexibility in the grid, reform markets and digitalise the system.[45] The Open Networks project, led by the Energy Networks Association, aims 'to standardise customer experiences and align processes to make connecting to the networks as easy as possible and bring record amounts of distributed renewables. For 2021, the project's workstreams are flexibility services, DSO transition, customer information provision and connection, among others. Under the DSO transition workstream, the project aims for Distribution Network Operators to make a transition to distribution system operators. This means that network operators will manage the network at a local level, having more control over demand and supply, making use of flexibility services, flexible connections, etc. Most of the identified DSO functions are expected to be implemented by 2028. In addition, DSOs are using Piclo,[46] a flexibility procurement platform for constraint management.
- Smart meter roll-out: UK has not completed the smart meter roll-out yet. In 2020, the smart meter penetration rate was 46%.[47]

2.1.5.3 Regulatory context

- Network tariffs: Distribution tariffs, known as Distribution Use of System (DUoS) charges are ToU tariffs that vary per region and are based on the consumed energy volume. The time banding mechanism (green, amber, red) is

44. http://powerresponsive.com/wp-content/uploads/2021/04/NG_MEUC-book-2021.pdf
45. https://www.stark.co.uk/resources/news/duos-red-band-charges-guide/, USEF, Flexibility deployment in Europe, 2021, SmartEN map 2019
46. https://piclo.energy/.
47. https://cdn.eurelectric.org/media/5089/dso-facts-and-figures-11122020-compressed-2020-030-0721-01-e-h-57999D1D.pdf

designed to encourage customers to spread their network usage across the day and avoid network usage during times of peak demand.

- Regulatory framework for demand-side participation: In Great Britain, nearly all products are technology agnostic, which means that in theory DSR can participate in balancing, adequacy and DSO constraint management services. Wholesale trading is only open for implicit demand-response participation within BRPs' portfolios. However, in practice, some of the products have certain requirements that makes it very difficult for aggregated DSR to participate. For example, the dynamic containment service has to be delivered at grid supply point (i.e. very limited geographical area), this makes it impossible for aggregators to get sufficient capacity from smaller/residential loads.

2.1.6 Netherlands

2.1.6.1 Supply and Generation

- Generation mix: The Dutch energy mix is largely dominated by fossil fuels. Intermittent renewables have a share of 19%, of which most of capacity comes from wind energy.

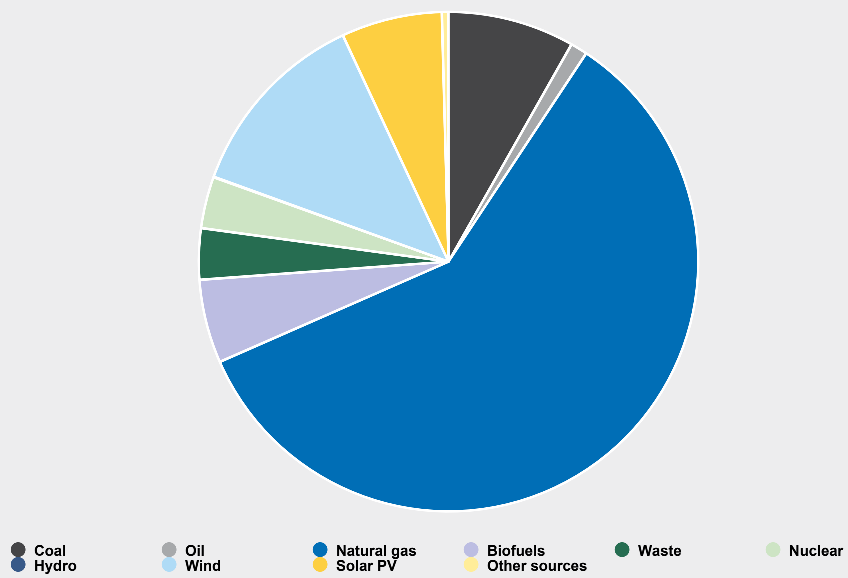


Figure 11. Generation mix 2020 – Netherlands[48]

- Retail competitive landscape: There are 38 energy suppliers in the Netherlands.[49] Switching rate is relatively high at close to 19% in 2018. However, a HHI index of nearly 2000 indicates a fairly concentrated market in the household sector, dominated by three large incumbents.[50]
- Energy tariffs: Customers may have flat, peak/off-peak or dynamic tariffs. In the residential sector, dynamic tariffs are not common, and there are only a few suppliers offering them. However, in the commercial and industrial sectors dynamic tariffs are the most common. In a typical electricity bill, the energy component represents over 40% of the share, which is significantly higher than other European examples.

48. https://www.iea.org/
49. https://www.overstappen.nl/energie/leveranciers/
50. https://www.ceer.eu/documents/104400/-/-/5c492f87-c88f-6c78-5852-43f1f13c89e4

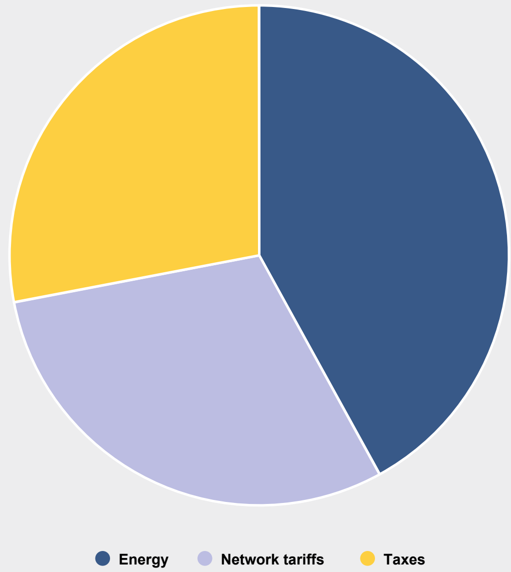


Figure 12. Electricity bill breakdown 2020 – Netherlands[51]

2.1.6.2 Network status

- Network investments, trends and digitalisation: There are network congestion problems at transmission and distribution level due to renewable penetration, electrification and also given the fact that the Netherlands has one of the densest EV charging station networks in the world.[52] To solve congestion, the TSO and DSOs have created GOPACS.[53] The GOPACS platform is intended to facilitate the coordination of the TSO and DSOs in the procurement of flexibility to solve network constraints on medium and high voltage. Next to that, TenneT is taking part in the Equigy initiative together with Terna and Swissgrid to facilitate flexibility at low voltage level (e.g. residential, EV chargers, etc) to participate in balancing services through an aggregator. Equigy is still at very early stages of deployment.[54]
- Smart meter roll-out: The Dutch smart meter roll-out is nearly complete, having 82.2% penetration in 2020.[55]

2.1.6.3 Regulatory context

- Network tariffs: The distribution tariff is a flat charge based on the customer's connection and applies to customers with a connection less than 3x80 A. 95% of the residential customers pay the same tariff, based on capacity. Large industrial customers are charged based on several aspects, including their maximum power.[56]

51. https://www.tennet.eu/e-insights/regulation-of-the-electricity-price/dutch-regulation/
52. https://www.dailysabah.com/life/environment/netherlands-has-the-largest-number-of-ev-charging-stations-in-Europe
53. https://www.gopacs.eu/
54. https://equigy.com/the-platform
55. https://cdn.eurelectric.org/media/5089/dso-facts-and-figures-11122020-compressed-2020-030-0721-01-e-h-57999D1D.pdf
56. USEF, Flexibility deployment in Europe, 2021, https://www.stedin.net/zakelijk/betalingen-en-facturen/

- Regulatory framework for demand-side participation: The ministry is working on a new energy law, for which a first draft is already available. This law includes provisions for DSOs to perform market-based congestion management and a definition for an aggregator and independent aggregator role.[57] To date, DSR can participate in balancing services (FCR, aFRR, mFRRda) and constraint management services for TSO and DSO. Flexibility can also participate implicitly in passive balancing within the BRP portfolio.[58]

tarieven
57. https://www.rijksoverheid.nl/documenten/publicaties/2021/11/26/wetsvoorstel-energiewet-uht
58. USEF, Flexibility deployment in Europe, 2021

2.1.7 Switzerland

2.1.7.1 Supply and Generation

- Generation mix: The Swiss energy mix is heavily dominated by hydro and nuclear energy, both sources account for 91% of the mix. Intermittent renewables, in particular solar PV, represents only a 4% share.

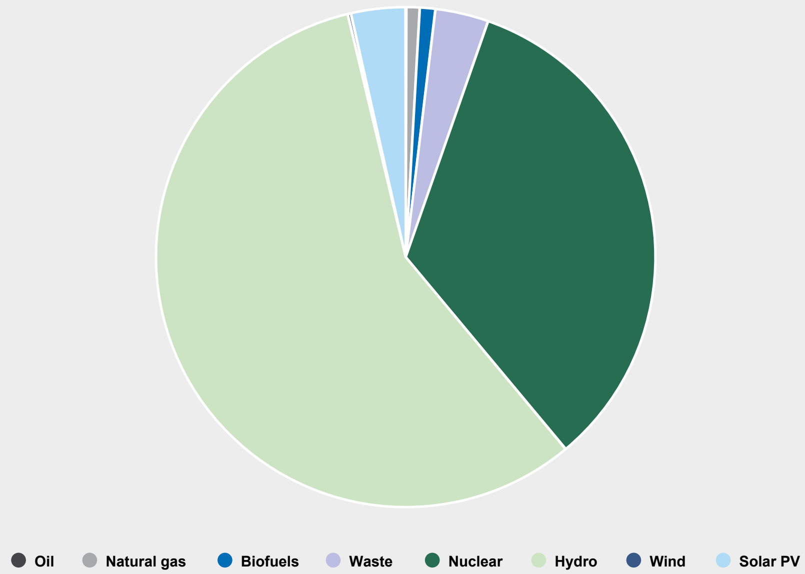


Figure 13. Generation mix 2020 – Switzerland[59]

- Retail competitive landscape: The Swiss retail market is not liberalised. Only consumers with an electricity consumption over 100,000 kWh, are allowed to choose their energy supplier. The latter group only represents 0.8% of the customers.[60]
- Energy tariffs: Peak/off-peak tariffs are available and are quite common. However, dynamic pricing is only available for customers of certain suppliers/ DSOs.[61] Like in Germany, half of the energy bill consists of taxes and levies, whereas the energy component is limited to a third of the bill.

59. https://www.iea.org/
60. https://www.bfe.admin.ch/bfe/en/home/supply/electricity-supply/federal-act-renewable-electricity-supply.html
61. Hive Power enables utility company to offer dynamic energy prizes to households (startupticker.ch)

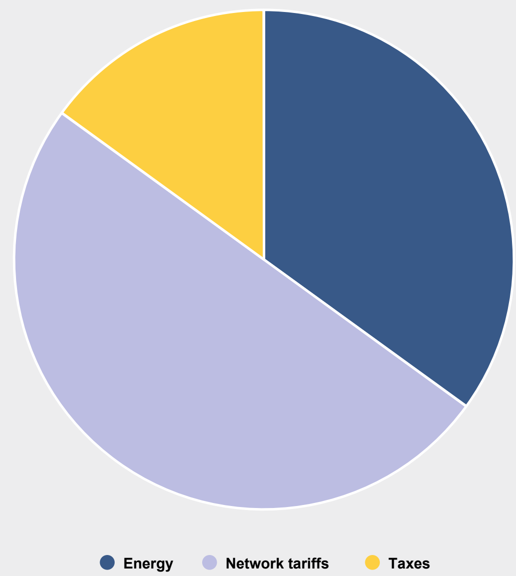


Figure 14. Electricity bill breakdown 2020 – Switzerland[62]

2.1.7.2 Network status

- Network investments, trends and digitalisation: In Switzerland there is a high density of DSOs with 630 registered, this also due to the Swiss market design. In terms of security of supply, flexibility is likely to become increasingly important, as Switzerland plans to phase out nuclear power by 2035 (34% of current supply).[63] Lastly, like in the Netherlands, Swissgrid and Zurich DSO EWZ are running pilots using the Equigy platform for residential customers to participate in flexibility markets.[64]
- Smart meter roll-out: Smart meter roll-out is far from complete in Switzerland, with approximately 17% penetration to date. According to the Energy Act, 80% of all metering equipment must be converted to a smart meter by 2027.[65]

2.1.7.3 Regulatory context

- Network tariffs: The Swiss transmission tariff is a flat rate tariff with a capacity and an energy volume component. The combination of distribution and supply charges is mostly based on consumed energy volumes and dependent on location (different locations show reasonably big price differences). Depending on the DSO and customer, the tariff is either flat or peak/off-peak.[66]
- Regulatory framework for demand-side participation: In Switzerland, DSR participation in balancing services was allowed as of early 2015.

62. https://www.swissgrid.ch/en/home/about-us/company/electricity-price.html
63. *Grid 2025, Swissgrid*, April 2, 2015, swissgrid.ch
64. Equigy – Crowd balancing platform (swissgrid.ch)
65. Connecting the dots: Distribution grid investment to power the energy transition - Eurelectric – Powering People
66. USEF Flexibility deployment in Europe

2.2 Aggregator model choices

2.2.1 Industrial and commercial sector

2.2.1.1 Aggregator model per service

In **Belgium**, the independent aggregator framework is relatively advanced, independent aggregators can participate in all markets, although with certain limitations. All independent aggregator models described in section 2 are implemented in Belgium for different products.

The uncorrected model is applicable for the FCR product, this is due to the fact that FCR is a symmetrical product, does not have energy payments, and has low energy impact at the perimeter of supplier's BRP. The BSP (independent aggregator) is remunerated with the capacity payment.

For mFRR, wholesale and the capacity remuneration mechanism, there are three different options. The first option, and what regulation dictates to be a necessary step, is the 'opt-out option' or contractual model – aggregator and supplier need to engage in negotiations to try to reach an agreement. If both parties cannot reach an agreement, the fall-back option is the central settlement model.

The central settlement model is implemented as described in section 1.3.3, the independent aggregator needs to either perform the BRP role or assign it to cover the balance responsibility of the flexibility during activations. Elia corrects the perimeter of the supplier's BRP and organises the transfer of energy (ToE) centrally, against a regulated price.

Alternatively, there is an option that can be implemented without the need to go through negotiations with a supplier, which are referred to as 'pass-through contracts'. This option is only available for large industrial customers that have their own balance responsibility or send schedules with the planned consumption to their supplier. The principle is that the flexibility activation does not affect the supplier since the customer is charged against their nomination and pay the deviation of their nomination at the imbalance price. When there is a flexibility activation, the aggregator would remunerate the customer for the use of their flexibility and for the extra costs charged by the supplier. This model can be mapped as a sort of corrected model, because the transfer of energy goes through the customer.

For the aFRR product, only the contractual and 'pass-through' or corrected models are available.

In **Finland** two models are in place – uncorrected and central settlement – based on the service type. The uncorrected model is applicable for the FCR-D and Fast Frequency Reserve (FFR) products, and like in Belgium, the supplier's BRP would be remunerated through the imbalance mechanism. For FCR-N and the mFRR pilot, Fingrid applies the central settlement model. The difference in the model used for FCR-D and FCR-N is due to the differences of both products. FCR-N activates significant amounts of energy, which causes a bigger impact on the portfolio of the supplier's BRP.

Fingrid implements slightly different variations of the central settlement model for

each service. For FCR-N, Fingrid corrects the perimeter of the supplier's BRP when flexibility is activated. Although the aggregator is financially responsible for the imbalance they may cause, they do not need to assign a BRP role. Fingrid facilitates the transfer of energy centrally: a transaction is made for balancing energy between Fingrid and the balance responsible party of the supplier's BRP at a price set by the balancing market in the imbalance settlement. If balancing energy is provided upwards then Fingrid pays and if balancing energy is provided downwards, then Fingrid charges. The aggregator receives the capacity payment. This mechanism can be considered as a central settlement model with the ToE price set at the balancing prices; as a result, any margin on the balancing prices end up with the supplier, rather than the independent aggregator.
During the mFRR pilot, Fingrid applied the central settlement model as described in section 1.3.3, however, the results and experiences of the pilot were deemed insufficient to draw many conclusions on the model.

In **France**, like in Belgium, we find the four models: uncorrected, central settlement, corrected and contractual. The uncorrected model is applied for the FCR and aFRR products, although for the latter there is hardly any participation since DSR can only participate through a secondary market. For the other services – mFRR, RR, capacity market and day-ahead and intraday trading – the other three models are applicable, but the choice is limited by the connection characteristics. If the connection is above 36 kV and has a specific type of contract,[67] the corrected model is the only option, whereas for connections below 36 kV, the model can be either central settlement or corrected (type A).

In terms of balancing responsibility there is a difference between the balancing mechanism and wholesale. The aggregator active in wholesale, needs to assign a BRP that covers the balance responsibility of the flexible resources during activation. This is not the case for the balancing mechanism where the aggregator acts as a 'floating BSP' that is financially responsible for the imbalances they cause in the system. Finally, it is important to note that the French regulation only considers demand turn-down (generation enhancement) as demand response, i.e. demand turn-up or generation turn down is not considered / facilitated.

In **Germany** there are two applicable models – uncorrected and corrected. The uncorrected model is applicable for the FCR product. For mFRR and aFRR, there is a corrected model in place since 2021. The German implementation of the corrected model is closer to the 'type B' described in section 1.3.3. After a flexibility activation, the aggregator exchanges schedules with the supplier's BRP so they correct their perimeter. Any imbalance resulting after the schedule exchange will remain in the supplier's BRP perimeter, hence no imbalance remains in the aggregator's perimeter. The supplier can then correct the energy bill to charge the customer as if no flexibility activation happened. Moreover, to enter this framework, aggregators must have a BRP certificate and negotiate with the supplier's BRP to determine the conditions for the schedule exchanges.[68]

In **Great Britain** we find two models – uncorrected and another model that could be mapped as either central settlement or corrected depending on the circumstances.

67. The customer must be settled for energy and network fees separately. The reason for this is because the correction should only apply to the energy contract, the network fees should always reflect the real consumption/generation.
68. https://www.bne-online.de/fileadmin/bne/Dokumente/Englisch/Policy_Papers/BNetzA_BK6_17_046_Beschluss_vom_14_09_2017.pdf

The uncorrected model is applied in balancing products, such as FCR (which participates outside the balancing mechanism[69]) and the capacity mechanism. For the Balancing Mechanism and RR, the second model applies. To participate in those services, the aggregator needs to register as a virtual lead party (VLP) which is essentially equivalent to a BSP role. The VLP nominates the flexibility activated in the supplier's portfolio ex-post activation[70] and ELEXON[71] corrects the perimeter of the affected BRPs. In case of under-delivery, the VLPs would incur imbalance costs (including an extra penalty if the imbalance cost is considered too low), however, for over-delivery the VLPs are not exposed to imbalance pricing.[72] The compensation aspect is designed around customer consent. If the customer consents that their activation data can be shared with the supplier, ELEXON would share the activation volumes with the supplier and thus the supplier could include it as a separate specification to charge the customer for the transfer of energy. This interpretation corresponds to the corrected model (type B). On the other hand, if the customer opts out of the data sharing, ELEXON would not share any activated volumes with the supplier leaving no option for them to charge compensation. This option could be mapped as a central settlement model with no compensation, i.e. transfer of energy price set at 0. According to ELEXON, they have no knowledge of any supplier that makes use of the activated volumes to charge compensation. Therefore, the closest model that represents the British situation is central settlement.

The access of VLPs to wholesale market is at the early proposal stage and they are considering the same model as they have implemented for the balancing mechanism (i.e. central settlement) although the details are not clear yet.[73]

In **the Netherlands** we find the same models – uncorrected and central settlement. The uncorrected model, as for the rest of the countries, applies to the FCR product, whereas the central settlement model is considered for aFRR and mFRR but not fully implemented yet. The new energy law proposal in the Netherlands prepares for a central settlement model[74] to facilitate independent aggregation. Currently, TenneT corrects the BRP perimeter after flexibility activations with the portfolio allocation data that the aggregator shares ex-post with TenneT. However, it is still required for the "independent" aggregator (BSP) to coordinate or make arrangements with the customer's usual supplier. This is foreseen to change in the future when the full central settlement model is implemented.

Finally, in **Switzerland**, we also find the same models – uncorrected and central settlement. Again, uncorrected is applicable for FCR whereas central settlement applies to aFRR and mFRR. To participate in these markets the aggregator must be a BSP, but not a BRP. Yet, the aggregator will face imbalance charges if they disturb the system balance.

The table below summarises the different models per country against the most common services/markets. From the table we can observe that the uncorrected and central settlement are the most common independent aggregator models that are implemented or planned to be implemented across the selected countries.

69. The balancing mechanism (BM) is one of the mechanisms that National Grid ESO uses to balance the system close to real time. The BM is based on a bid-offer mechanism.
70. The validity of this information is based on trust
71. ELEXON is the imbalance settlement responsible party in Great Britain
72. https://www.elexon.co.uk/documents/training-guidance/bsc-guidance-notes/virtual-lead-party-vlp-entering-the-market/#:~:text=A%20VLP%20is%20a%20distinct,to%20trade%20in%20wholesale%20markets
73. https://www.elexon.co.uk/mod-proposal/p415/
74. Exact model will be specified by lower legislation, yet the NRA has indicated that the central settlement model is the likely direction of travel

	FCR	aFRR	mFRR & RR	Wholesale	Capacity market
Belgium	Uncorrected	Contractual Corrected (only applicable when customer nominates their energy schedule)	Contractual Corrected (only applicable when customer nominates their energy schedule) Central settlement	Available from 2021: Contractual Corrected (only applicable when customer nominates their energy schedule) Central settlement	Contractual Corrected (only applicable when customer nominates their energy schedule) Central settlement
Finland	Uncorrected (FCR-D and FFR) Central settlement (FCR-N)	n.a.	Central settlement model was piloted	n.a.	n.a.
France	Uncorrected	Uncorrected	Corrected Central settlement Contractual (only applicable for connections where central settlement is applicable)	Corrected Central settlement Contractual (only applicable for connections where central settlement is applicable)	Corrected Central settlement Contractual (only applicable for connections where central settlement is applicable)
Germany	Uncorrected	Corrected	Corrected	n.a.	n.a.
Great Britain	Uncorrected or Central settlement	Central settlement*	Central settlement*	Central settlement under discussion for future implementation	Capacity market: Uncorrected Wholesale: n.a.
Netherlands	Uncorrected	Plan to implement Central settlement	Plan to implement Central settlement	Contractual	n.a.
Switzerland	Uncorrected	Central settlement	Central settlement	n.a.	n.a.

Table 4. Aggregator models per country

2.2.1.2 Balance responsibility

The balance responsibility of independent aggregators is implemented in different ways in each country and product.

In general, for **trading DSR in the intraday (ID) and day-ahead (DA)** markets, independent aggregators need to assign or perform the BRP role. This is the case in France and Belgium, the only two countries that have opened access to the wholesale market to independent aggregators. The independent aggregator's BRP (BRP_{agr}) does not have the same status as the supplier's BRP (BRP_{sup}). Whereas the BRP_{sup} represents and is responsible for the customer connection at all times, the BRP_{agr} is only responsible for the system imbalances that the flexibility activations may cause, and therefore resembles a trading-only BRP.

How that works in practice is quite complex, for illustration purposes, we will take the Belgian example for transfer of energy applying **central settlement** in wholesale[75]:

1. Day-ahead: the BRP_{agr} sells X MWh for period P on day D to a flexibility requestor's BRP (BRP_{frp}). BRP_{agr} nominates X in their programme as a selling trade. BRP_{agr} is in imbalance by X MWh.
2. Day-ahead: BRP_{agr} needs to nominate, as a buying trade, the X MWh that will be activated in the aggregator's portfolio so the BRP_{agr} is in balance.
3. Intraday: The aggregator activates X MWh of flexibility during period P. The aggregator communicates to the Elia (Belgian TSO) the delivery volume per connection point, before, during and after activation. At the same time, the TSO communicates to the BRP_{sup} the amount of flexibility that is being activated on their portfolio, to avoid any counterbalancing actions on their side.
4. After delivery: Elia quantifies the delivered volumes by comparing the metering at the connection to the baseline. The baseline methodology is defined in the transfer of energy rules. Elia corrects the perimeter of the BRP_{sup} and BRP_{agr} based on the delivered flexibility.
5. Finally, the imbalance settlement is performed and the financial compensation between BRP_{agr} and BRP_{sup} is arranged. This topic will be addressed in the next section.

When applying the **corrected model** (type A) in France, the BRP implementation is similar, except for the correction aspect. The correction takes place at the meter data, therefore RTE (the French TSO) does not need to perform any perimeter correction on BRP_{sup}'s portfolio. It still needs to perform the perimeter correction on the BRP_{agr}'s portfolio.

For **balancing services**, there are different approaches to balance responsibility:

- The independent aggregator (BSP) needs to assign/perform the BRP role: This is the case in Belgium, and in the Finnish pilot for mFRR. The implementation of the BRP role in the context of balancing services is similar to how it is implemented for ID/DA trading in the previous example. The main difference is that the perimeter correction of BRP_{agr} is performed based on the ordered flexibility volume by the TSO. Therefore, any over or under-deliveries will create an imbalance in the BRP_{agr}'s portfolio.

75. https://www.elia.be/-/media/project/elia/elia-site/electricity-market-and-system---document-library/transfer-of-energy/2020/2020_07_design_note_toe_da_id.pdf

- The independent aggregator (BSP) does not need to assign or perform the BRP role, but is financially responsible for its imbalances: this is the case for most of the analysed countries. When applying this in the central settlement or corrected (type B) model, the TSO corrects the BRP_{sup}'s perimeter by the delivered calculated flexibility (per connection, declared ex-post by the aggregator).[76] Because the aggregator is required to provide the requested amount of flexibility, any deviation to the requested amount is considered to cause an imbalance in the system, therefore the BSP is penalised. Depending on the implementation there are differences on how the BSPs are penalised. For example, in GB, BSPs are penalised for under-delivery of the requested amount but not for over-delivery.

The table below summarises the implementation of balance responsibility for independent aggregators. Note that for the models where aggregators need to assign a BRP, the aggregator is only balance responsible for moments when flexibility activation occurs, and only for the flexible part (deviations from the baseline). For the rest of the time, the balance responsibility is held by the supplier's BRP, and during the activation, for sourcing the baseline.

76. In Germany, the correction takes place through schedule exchanges between BRP_{sup} and BRP_{agr}

	Balancing services	Wholesale & Adequacy
Belgium	Independent aggregators are BSPs and need to be/assign a BRP, except for FCR.	Independent aggregator needs to be/ assign a BRP
Finland	Independent aggregators are BSPs and they have no need to be or assign BRP for participating in FCR-D, FCR-N or FFR. For the mFRR pilot the ind. aggregator had to assign BRP.	N/A
France	Independent aggregators in balancing markets are considered "floating BSPs" and are exposed to imbalance prices, but they are not a BRP.	Independent aggregator needs to be/ assign a BRP
Germany	Independent aggregators are BSPs and do not need to assign a BRP. However, they need a BRP certificate, issued by the customer's BRP.	N/A
Great Britain	VLP are equivalent to BSPs, they do not have the BRP role. They are exposed to penalties (at least the imbalance price) for underdelivery but they are not exposed to imbalance prices for overdelivery.	No need for BRP to participate in the capacity market
Netherlands	Independent aggregators or independent BSPs do not need to be/ assign BRPs. They get penalised as part of the product specifications.	N/A
Switzerland	Independent aggregators are BSPs. They bare financial responsibility for imbalances as part of the service delivery, but they do not need to be or assign a BRP.	N/A

Table 5. Balance responsibility for independent aggregators per country

2.2.1.3 Compensation

In **Great Britain**, if the customer consents to sharing their data, the supplier could charge the consumer for the flexibility through a different specification, and the aggregator would compensate the consumer. If the customer does not consent to sharing the data, there is currently no compensation between aggregator and supplier. This corresponds to a transfer of energy price set to 0, i.e. the aggregator does not pay for the sourced energy to the supplier. This is likely to change in the future, especially due to the discussion of opening the wholesale market to VLPs. The initial proposals suggests that the compensation between aggregator and supplier should be considered.

In **Switzerland** the compensation between aggregator and supplier is organised through the transfer of energy payment. Swissgrid settles the transfer of energy centrally for the volume of flexibility delivered at the day-ahead spot price for the time of activation. In **Finland** the same principle has been applied for the mFRR pilot, whereas for the FCR-N, the transfer of energy price is set at the balancing price.

In **Germany**, the aggregator compensates the supplier through the customer at the retail price level for the sourced energy. Next to the retail price, the aggregator may compensate the supplier's BRP to cover the administration costs for schedule exchanges, it is up to the BRP (in negotiations with the aggregator) to set the price.

The **Belgian** models, like the Swiss and Finnish, only requires compensation for the transfer of energy. When the corrected model is applicable, the transfer of energy price is set at the retail energy price. However, when the central settlement model applies, the settlement is arranged centrally by Elia, and the transfer of energy price is set by a formula. This formula was created by the regulator and is based on the following principles:[77]

- The purpose of financial compensation is to prevent the supplier or the aggregator from being harmed by the flexibility activation; the transfer price should ideally match the price at which the customer buys its electricity from the supplier.
- Since retail prices may differ from customer to customer and is not publicly available information, the transfer of energy price formula is designed as an approximation of the average sale price of electricity (energy component of the bill) for a standard portfolio of customers in the electricity market.
- The ToE price is based on market indices. In particular the regulator chose future markets (Cal Y+2, Cal Y+1, M+1) and the day-ahead spot market, under the assumption that the energy would be sourced at different points in time. The intraday market is not considered because it is not sufficiently liquid yet to represent a stable source for the customer supply. Regarding ratios between markets, the Belgian regulator suggests fixed ratios. The ratio between short term and future market should be based on the average ratio of flexible consumption to baseload consumption of industry.
- The ToE should encourage the contractual model. The Belgian regulator deems the contractual model the most efficient from the point of view of the market, therefore they introduce a factor of uncertainty on the regulated price during the time of the negotiation, which in this case is the day-ahead element.
- The ToE should approximate the electricity selling price, by accounting for the supplier margin and the diversity of selling prices.

These principles resulted in the following formula:

ToE price={[73 %× 1/3 (Cal Y+2 + Cal Y+1 + M+1) + 27 % EPEX spot BE DAM] × 1,05} +/- 5 %

With:

- CAL Y + 2 = the average of the daily quotations published by ICE ENDEX during the year two years before the year of activation for the product baseload,
- CAL Y + 1 = the average of the daily quotations published by ICE ENDEX during the year preceding the year of activation for the baseload product,
- M + 1 = the average of the daily quotations published by ICE ENDEX during the month preceding the month of activation for the baseload product,

77. B1677FR.pdf (creg.be)

- EPEX spot BE DAM = the quotation published by EPEX spot Belgium on the day ahead market for the time during which the activation takes place.
- +/- 5 % = asymmetric element to distinguish demand turn-up from turn-down.

The **French** model shares the same compensation principles with Belgium, except for the ToE price formula. The formula attempts to reflect the average sourcing cost for electricity and differentiates between two types of sites: profiled and half-hourly settled sites. The latter category is the relevant one for industry and commercial. Unlike the Belgian approach, RTE publishes the prices for the coming year in the preceding month of December and the prices are fixed with a time of use component (peak/off-peak) and season (winter/summer). The price formula only considers future market prices (for Cal Y+1 and Cal Y+2) and ARENH price (Regulated access to historic nuclear energy). Moreover, to consider the arbitrage between future markets and ARENH, there are two different formulas. The comparison between ARENH and average future market prices, determines the formula to be used each year. The complete formula can be found in NEBEF rules 3.3.[78] According to CRE, market parties have expressed their concern that the formula does not include capacity mechanism prices. CRE has indicated that they are updating the formula to include those prices from 2023.

In the table below we summarise the compensation between aggregator and supplier for each country.

78. 2021.01 Rapport d'accompagnement Règles NEBEF 3.3.pdf (services-rte.com)

	Compensation
Belgium	Price level for the transfer of energy is (an approximation of) the retail price. - Corrected model: ToE is price is equal to the energy part of the retail contract and imbalance prices. Network fees and taxes are charged for the actual consumption. - Central settlement model: ToE price is calculated with a formula set by the regulator.
Finland	Price level for the transfer of energy is either imbalance price or DA spot market price - For FCR-N, ToE is set at imbalance price. - For mFRR pilot it was set at DA price.
France	Price level for the transfer of energy is either retail price or (an approximation of) the sourcing costs. - Corrected model: ToE is price is equal to the energy price of the retail contract. Network fees and taxes are charged for the actual consumption. - Central settlement model ('regulated model'): ToE is different depending on the type of customer, and the time of the year. The formula is set by the regulator and the parameters are updated yearly.
Germany	Price level for the transfer of energy is the retail price; additional administrative costs may be compensated - ToE is compensated at the price of the energy price retail contract. There is also the possibility for the BRP to charge administrative costs for the exchange of schedules.
Great Britain	Price level for the transfer of energy is both set and not set: - If customer shares their data, the supplier could charge the customer through a separate specification. The price is not regulated. - If customer does not share their data, the compensation is currently 0. Setting the ToE at a different price is under discussion.
Netherlands	No price level set (no ToE implemented) - Central settlement not fully implemented. This corresponds to a price of 0 as part of the central mechanism, yet the compensation is agreed between the Supplier's BRP and the aggregator (and therefore not an independent model). The transfer of energy price for central settlement will be prescribed by lower legislation in the future.
Switzerland	Price level for the transfer of energy is DA spot price - For participation in balancing products, the ToE price is set at DA price.

Table 6. Compensation level per country

2.2.1.4 Other aspects

Next to the aggregator model and the compensation mechanism, several other aspects need to be considered when implementing an independent aggregator framework.

The **baseline methodology** is key to quantifying the flexibility delivery not only for services but also for the transfer of energy. The baseline methodology for service delivery should be set by the system operator and is strongly dependent on the service requirements, such as response time, sustain time, etc.

For day-ahead and intraday markets, however, the baseline methodology for the transfer of energy should be regulated. Therefore, in this section, we focus on wholesale markets.

Only France and Belgium have implemented ToE for day-ahead and intraday trading, so the experience is rather limited. In Belgium**,** a historical baseline methodology is applied, whereas in France there is a choice between meter before meter after (MBMA), historical and nomination baseline methodologies. For the latter, the requirements to be eligible for nomination baseline are quite strict in terms of timing (e.g. the baseline needs to be submitted two weeks in advance) and accuracy, which makes it difficult for aggregators to comply.

The **rebound effect** and how to deal with it is one of the complexities of DSR, especially in combination with independent aggregation. Without further regulation, the rebound ends up in the supplier's portfolio, potentially leading to imbalances. The aggregator is currently not responsible for the rebound effect in any of the studied countries: neither with respect to balance responsibility, nor to sourcing position. Countries like Germany have included a clause to further study this aspect with the return of experience from market parties. In France, rebound rules have been approved to consider the impact of rebound on the imbalance created for the supplier's BRP. Nevertheless, the rules have not been applied yet because they are not considered a priority by market actors. Also in France, rebound effect will be taken into consideration when measuring the accuracy of the baseline, i.e. the rebound periods will be excluded from the calculations.

Another element is the **IT systems** used to facilitate independent aggregation, for example tasks related to perimeter correction, meter data collection, and flexibility settlement. Note that this does not intend to cover flexibility market platforms. Several TSOs have implemented their own platforms for perimeter correction and settlement, such as France and Netherlands. Next to that, there are data hubs but in general they do not support data collection for assets behind-the-meter. In Belgium, the Atrias data hub in planned to include functionality to facilitate the market access to distributed assets.[79] Switzerland, the Netherlands and part of Germany are piloting Equigy Crowd Balancing platform.[80] This is still not part of BaU for Swissgrid, but TenneT is already using it, as one of the alternatives that BSPs have to transfer data. TenneT still relies on other systems for bidding and BRP perimeter correction.[81] In Switzerland, since there is no data hub, the information exchange and perimeter correction still lacks automation. Therefore, Swissgrid requires the aggregator to send schedules (15-minute granularity) with the delivered energy each day after delivery. As A. Chacko et al. mention in their paper,[82] in Switzerland "managing the data of technical units changing their suppliers and balance groups is not yet ideally resolved as there is no central data hub at present which could support automation of such activities". Another possible improvement to manage the high data volumes could be to make use of the metering systems to correct the activated energy of the balance groups instead of exchanging schedules."

79. https://eu-sysflex.com/wp-content/uploads/2021/03/EUSYSFLEX-5.1.3-Report-Data-Platforms-FINAL-1.pdf
80. https://equigy.com/the-platform/
81. https://www.tennet.eu/fileadmin/user_upload/SO_NL/aFRR_manual_for_BSPs_en.pdf
82. https://www.qualygrids.eu/app/uploads/sites/5/2020/01/D180128-Central-Settlement-Model-Final-V2R0.pdf

2.2.2 Residential

The experience with residential flexibility by independent aggregators is limited to France, Finland and Switzerland. In Belgium, LV assets are not allowed to participate in balancing services; in GB and Germany, connections have to be half-hourly / quarter-hourly settled to participate in services and markets, which is not the case for most residential customers. In the Netherlands there is only residential participation within the supplier's portfolio.

In France, Finland and Switzerland, the models applicable for residential flexibility are the uncorrected and central settlement model, although contractual is also a possibility. France implemented the central settlement model for smaller connections because the corrected model could have not been applied due to legal issues, e.g. metering that is used for customer settlement cannot be modified. A second obstacle for the corrected model is the fact that energy and grid tariffs are combined on the same bill, whereas grid tariffs need to be based on the physical use of the customer.

The Swiss and Finnish model for the residential sector is identical to the model for the industrial sector. However, the French model for the residential sectors shows several modifications, in particular the transfer of energy price, the baseline methodology and the perimeter allocation.

In France, the transfer of energy price for profiled customers, typically residential, is different from telemetered customers. The calculation of the ToE depends on the type of customer tariff and, similar to telemetered sites, is fixed on an annual basis for peak and off-peak hours. The ToE price is based on the 'cost of sourcing energy' in the annual CRE report 'reglementary tariffs for selling energy'.

Since wholesale settlement of residential customers is based on synthetic load profiles in France, the perimeter allocation among the affected BRPs is performed by repartitioning between all households based on their subscribed power. The volume of the allocation is based on the difference between the calculated baseline and the metered power for participating (activated) customers. For the residential sector, there is a special baseline that is called 'site to site rectangle' which is a modified MBMA. Unlike for other baseline types, there is no prequalification required for the residential sector to use the site-to-site rectangle baseline.

2.3 Deployment experience

2.3.1 Participation in markets and services

In the table below we capture the information available on DSR participating in the different markets and (where possible) the extent to which the aggregator framework is used. The DSR numbers shown are not limited to independent aggregation.

Table 7. DSR participation per country

Country	FCR	aFRR	mFRR (& RR)	Wholesale	Capacity market
Belgium	Main capacity comes from distributed assets (i.e. not large generators)	N/A	10 BSPs (i.e. aggregators) and 24 suppliers offer balancing services. Around 47% of the delivery points use either the corrected or the central settlement aggregator model. Most of the volume comes from distributed assets.	Transfer of Energy in day-ahead and intraday markets just went live, no results yet.	In the first Y-4 auction, 7% of total capacity was awarded to DSR (~300 MW)
Finland	FFR: 80 MW FCR-D: 410 MW FCR-N: 10 MW	N/A	mFRR up: 90-530 MW mFRR down: 0-100 MW	Implicit within BRP portfolio. DA: 200-600MW ID: 0-200MW	N/A
France	In 2020, demand response capacity represented 18% of FCR volume.	N/A	In 2020, demand response capacity made up 45% of mFRR	Demand response volumes selected through the NEBEF mechanism reached 11 GWh in 2020, half the level recorded in 2019	In 2019, around 2,3 GW of demand response was contracted under the capacity mechanism
Germany	In 2018, industrial DSR participation of +/- 80MW	In 2018, industrial DSR participation of + 540 MW / - 660 MW	In 2018, industrial DSR participation of + 880 MW / - 840 MW	N/A	N/A
Great Britain	350 MW contracted capacity in 2020 in dynamic containment product. 800-1200 MW contracted for FFR in 2020, mostly from storage	N/A	In 2020, around 5 to 20 GWh were dispatched per month in the balancing mechanism.	N/A	Around 1,2 GW DSR contracted in the T-4 action in 2019.

Nether-lands	30 MW of storage is active in the FCR market in 2019	N/A	90 MW of demand response active in ancillary services (excluding demand-side generation).	It's estimated that around 700 MW of demand response was active in the day-ahead market during the years of 2018, 2019 and 2020, within the BRP's portfolios.	N/A
Switzer-land	3 MW of DSR participated in FCR in 2017	18.5 MW DSR participated in aFRR market in 2017, of which 8.5 MW industrial.	49 MW of DSR in mFRR market in 2017.	N/A	N/A

Notes:

Belgium[83] [84]
Finland[85]
France[86]
Germany[87]
Great Britain[88]
Netherlands[89] [90]
Switzerland[91]

2.3.2 Today's earnings models

Most of the earnings models today are based on industrial and commercial flexibility, and most aggregators are not applying an independent aggregator model. Only a few independent aggregators are active in the residential sector.

In general, aggregators in the **industrial sector** rely mostly on capacity payments, and they mostly participate in balancing products and adequacy services such as strategic reserves or capacity markets. Energy payments represent only a small part of their revenues, since flexibility activations are not very frequent since industry has a relatively high marginal cost.

Aggregators agree that the industrial customer's main driver is monetary remuneration for their flexibility and to a lesser degree they value the participation

83. https://www.elia.be/-/media/project/elia/elia-site/ug/wg-balancing/balancing-meetings/20210317_wg-balancing_slides.pdf
84. https://www.elia.be/-/media/project/elia/shared/documents/press-releases/2021/20211031_crm-results-of-first-auction-now-available_en_v2.pdf
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90. https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/20200117_TenneT_Flexibility_Monitor.pdf
91. https://riunet.upv.es/bitstream/handle/10251/176164/Ribo-PerezLarrosa-LopezPecondon-Tricas%20-%20A%20Critical%20Review%20of%20Demand%20Response%20Products%20as%20Resourc....pdf?sequence=1

in the energy transition. Other elements are usually information portals or energy use insights; however these elements are a 'nice to have', not a deal breaker.

Due to the highly competitive environment, in some of the markets, the aggregator's value proposition continuously changes, as does the terms in their contract with customers. But in general, the value proposition to industrial customers is the revenue from participating in different services. The aggregator usually applies revenue sharing (some of them 50%, some others in a different way) with the customer.

Moreover, today's earning model are more and more relying on a multimarket approach. In the past, a portfolio of assets would offer one service, but today, to the extent possible, the same flexible pool or asset can participate in multiple products or markets (simultaneously or not, depending on the requirements) and bid in the markets that offer the most revenue in a particular moment.

In the **residential sector**, the earning models and value proposition are quite different from the industrial sector. Residential flexibility is more CAPEX intensive and has typically low marginal costs, because they manage assets like heat pumps, electric heaters, EVs and residential batteries. From interviews with aggregators, we identified various customer propositions for independent aggregators:

- The aggregator offers the customer a portal to monitor their energy consumption, or home energy management system (HEMS) and the possibility to set 'energy savings mode' for free. The customer does not get any additional remuneration.
- The aggregator partners with flexible asset providers (e.g. battery provider), and when a customer buys the asset, he/she can get a discount by allowing the aggregator to sell the flexibility.

Aggregators find that the main driver for residential customers today, are not the earnings or savings. The customers are in general first movers that are driven by innovation and participating in the energy transition.

Independent residential aggregators can only monetise their flexibility in a few markets, namely, France, Finland and Switzerland. In France they can access the most revenue streams (balancing, adequacy and wholesale). Yet, according to one of the interviewed aggregators, the business of independent aggregators who are only active in the residential sector is difficult to sustain with the current market design because DSR is required to bear the cost of compensation to suppliers. Most aggregators active in this sector have separate sources of revenue, in either the industrial sector, or as an IT provider. For example, in France flexibility participation has reduced in the past year, because the revenues for aggregators were not enough to cover their costs once compensation is considered. Due to the need for additional flexibility in the system to achieve climate policy goals set in the law, including adequacy issues in the short and medium term, the ministry had to increase the additional capacity payment, (under a state aid regime usually referred to as 'appel d'offres effacement')[92] that aggregators could get on top of the usual markets. The European Commission published their official analysis of the French market reform plan, and raised their concern that activated volumes are fairly small (not only in residential DR, but overall in DSR participation in all "energy" markets, as opposed to

92. The increase of the subsidised additional capacity payment was approved by the European Commission following a request from the French ministry, as per the state aid European legislation.

capacity). The Commission states they "invite France to carefully monitor the volumes of energy effectively activated as persistently low energy volumes may be the sign of market barriers."

2.3.3 Aggregator's feedback

We have conducted interviews with nine aggregators active in the countries in this study to get their feedback on the current aggregator models, what improvements they suggest and what elements are required for them to be active in a market. Most of the interviewed aggregators are active in the industrial and commercial sector, only two of the interviewed aggregators have extensive experience in the residential sector. Three of the interviewed aggregators are affiliated to a supplier but all nine of them perform independent aggregation to a certain extent.

For most aggregators the following elements make a market attractive:

- Have an aggregation framework in place that does not require interaction with the supplier.
- Have a simple and scalable process for the aggregator.
- Appealing balancing and energy prices.
- There is a need for flexibility in the market, e.g. adequacy issues.
- Subsidies, e.g. the appel d'offres tender in France provides an extra capacity payment for flexibility to be available in the market.

Next to the regulatory framework, the markets and services must be designed to allow DSR participation in a level-playing field. For example, technology-inclusive baseline design and accuracy requirements, allowing for aggregation of flexibility in multiple geographical areas, suitable pre-qualification requirements for portfolios with large amount of assets, reasonable metering requirements for portfolios with large amounts of assets (e.g. not requesting high granularity data per asset in the portfolio),[93] the possibility of stacking different products and to perform dynamic pooling.

Regarding aggregator models, the conclusions from the interviews are as follow:

- Aggregators prefer that perimeter corrections and settlement are performed centrally.
- In general all aggregators seem satisfied with the central settlement model.
- Most aggregators agree that the French model is very advanced and complete.[94]

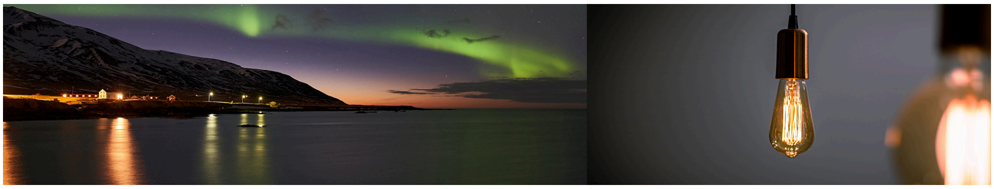
Aggregators were concerned not only with the available models but also the barriers to applying them. Aggregators active in Belgium complain about the need of having to explore the contractual model first because it never results in an agreement and they always end up using the fall-back option anyway (i.e. central settlement). The reality is that this requirement only adds administrative burden and barriers for aggregators. Therefore, they would prefer having the possibility to apply central settlement directly, just like they can in the case of the corrected model.

93. This particularly applies for the cases where there is no data hub or straight-forward communication channel
94. Although the decreasing participation of Demand Response as well as the European Commission analysis of the reform plan show that the market design is not optimal for the participation of DR resources.

In terms of compensation to the supplier the conclusions are:

- Aggregators agree with the need for the supplier to be compensated when a corrected or a central settlement model is used. Most industrial aggregators do not find the compensation to suppliers a burden, since, so far, they operate mainly on markets that have a small number of energy activations such as primary reserve and capacity remuneration mechanisms. However, some industrial aggregators and residential aggregators find that the transfer of energy or compensation to the supplier is detrimental to their business case. These aggregators insist on the fact that such a financial compensation shall not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility as stated in the EU Directive 2019/944 on the internal electricity market. These aggregators believe that a net-benefit model should be applied.
- In the German case, the aggregator found it unfair that the BRP can charge them for the administrative costs of the schedule exchanges. This charge is not regulated, and it must be based on bilateral negotiations between the aggregator and the supplier's BRP.

Regarding balance responsibility, most independent aggregators agree that having balance responsibility (only during flexibility activation) or only being financially responsible for imbalance have more or less the same impact. Bearing balance responsibility only adds an administrative burden, but it does not kill the business case. However, a few aggregators considered that having balance responsibility is a risk, especially for a starting business with low liquidity or bank guarantee. Moreover, in the case they assign a third party to perform the BRP role, they would need to share revenues.



Bakkagerdi, Iceland

3. LESSONS LEARNT FOR THE NORDIC INDEPENDENT AGGREGATION FRAMEWORK

This chapter contains the lessons learnt for the Nordics on the implementation of the independent aggregator regulatory framework. The analysis is done based on the international experience described in section 2 and the Nordic context. Due to the differences in deployment and experience in the industrial & commercial, and residential sectors, the chapter will be split into each of the respective sectors.

3.1 Industrial and commercial

This section contains the lessons learnt on the implementation of the independent aggregation in the industrial & commercial sector and it addresses the following questions:

1. What triggered the implementation of a regulatory framework for aggregation?
2. Which model was chosen to facilitate independent aggregation?
3. What should be the level of compensation / price formula?
4. Is the uncorrected model applied? For which products?
5. Do independent aggregators already have access to wholesale markets?
6. What are important factors for aggregators to enter (national) markets?
7. How is rebound handled?
8. What kind of IT systems are used to facilitate (independent) aggregation?

#1

Question: What triggered the implementation of a regulatory framework for aggregation?

Observations from other countries

Whereas some countries are solely responding to the electricity market directive, other countries have started implementing a regulatory framework (well) prior to the publication of this directive.

In France several aggregators were already active, through a 2007 experiment that relied on contractual models. This meant that aggregators needed to establish contracts with suppliers, which (at the same time) could also act as an aggregator. In 2012, the competition authority, CRE, decided to turn the experiment into permanent rules, realising that the regulatory framework was needed to establish a level playing field. Hence, the compensation between aggregators and suppliers could not rely on agreements but had to grant independence to aggregators. The decision resulted in the current framework, NEBEF, that started in 2014. The corrected model was adopted for connections above 36kV and/or a certain type of contract, where some industrial customers operate, and the central settlement model for connections that do not fulfil the previous conditions.

In Switzerland, there was a need for more balancing power, as the incumbent service providers (relying on Hydro resources) were offering lower balancing energy every year. SwissGrid opened their balancing products for both demand-side resources, but also for new market entrants (aggregators). To ensure a level playing field, a regulatory framework was needed based on a central settlement model.

In Belgium and Great Britain, aggregators were already active in the market, triggered by the Belgian strategic reserves product, and by an mFRR product in GB, both targeting demand-side participation. For these products, an uncorrected model was used, which is a simple model suitable for capacity products with relatively small energy-components. Both countries decided to allow these market players and demand-side technologies access to other markets and products as well. Since these markets involve higher energy transactions, Belgium has moved (and GB is moving) towards more advanced frameworks, both applying a central settlement model.

The Netherlands have not met the deadline for implementing Article 17 of the electricity market directive. For balancing services, a central settlement model is currently being designed and is expected to be implemented, based on the most recent draft of the new energy law (the so-called "UHT-version")[95]. For intraday and day-ahead trading, the decision has not been made yet. According to this draft energy law, independent aggregators are not allowed to trade in wholesale markets, unless they have a contractual agreement with the BRP of the customer. The BRP is obliged to provide any aggregator (which has agreed with the customer on demand response services) with a reasonable contract proposal, to agree on financial compensation, electricity nomination, imbalance costs compensation and data exchange. The financial compensation needs to be based on a method that will be included in future lower legislation. Also other aspects of this contract can be dictated by future legislation (volume calculation and other content), as well as maximum timelines for providing such a proposal. Based on a (non-legal) assessment by DNV, it is questionable if such a model would be fully compliant with the electricity directive, as it still relies on a contract with another market party - although the content of the contract is heavily regulated.

Whereas the Netherlands are undecided, members of the Germany's NRA clearly dislike the concept of independent aggregation due to a fear of creating arbitrage options for the aggregator that could lead to market distortions, at the expense of suppliers. Whereas they see the value of aggregation and demand side participation, they believe the supplier is the only market party that should be allowed to aggregate and valorise this flexibility among its consumers. Still, Germany has implemented a corrected model as of 1 Jan 2021, which meets Article 17 of the electricity market directive and allows aggregators to conduct two separate aggregations in parallel for the same consumer. The NRA expects that this model will be used infrequently as there still needs to be a so-called 'BRP agreement' between the aggregator and the customer's BRP. In this agreement they negotiate the terms of schedule exchanges (as described in section 2.2.1.1) and possible prices for those. Although the aim of the German model seems to be compliance with the EU directive, the discussion started a lot earlier when it was triggered by the Electricity balancing Guideline while also being driven by a number of companies that performed aggregation. The first German decision on the corrected model was already made in 2017 and it was only related to secondary balancing energy[96]. The background seems to be the NRA's concern about the weakening of balancing obligations. The NRA published a restrictive industry guideline on aggregation back in 2016.[97]

In other countries, especially the Netherlands and the UK to lesser extent, the discussion on independent aggregation was preceded and triggered by the implementation of the Electricity balancing Guideline. Implementing a BSP independent from the BRP mirrors, to some extent, the separation of the supplier and aggregator role. Since the independent aggregator can also perform the role of BSP, consistency between both implementations is important. Both in the Netherlands and GB, independent aggregators performing the BSP role are allowed to participate in balancing services, i.e. BSPs independent to the BRP of the

95. https://www.rijksoverheid.nl/documenten/publicaties/2021/11/26/wetsvoorstel-energiewet-uht
96. https://www.bne-online.de/fileadmin/bne/Dokumente/Englisch/Policy_Papers/BNetzA_BK6_17_046_Beschluss_vom_14_09_2017.pdf
97. https://www.bitkom.org/sites/default/files/file/import/Branchenleitfaden-Drittpartei-Aggregator-2.pdf

connection. TenneT and Elexon have implemented a mechanism to correct the perimeter of the BRPs that are affected by BSPs activations, which in turn is a start to the implementation of a central settlement model.

Nordic context

So far, little activity has been observed valorising demand-side flexibility, and hardly any aggregator has entered the Nordic markets. In general, experience has been through pilot projects and innovation initiatives. The exception is Finland, where we observe the highest demand response participation compared to the other Nordic countries. Finland had less flexibility capacity available due to less hydro power and less interconnector capacity, which encouraged the TSO, Fingrid, to be more open to new technologies participating in balancing markets, as well as aggregators and independent aggregators (only on short-term balancing markets – FCR and FFR). Some aggregators consider that, Sweden, with more interconnection capacity and hydro, has moved slowly in DSR enablement and innovation. Nordic countries need to implement both the electricity balancing guideline and the electricity market directive (incl. Art. 17), with only Norway facing different time horizons.

Lessons learned

Main reason for Nordic countries today seems to be the implementation of the EU directive, in this sense the lessons learned from all countries are relevant. Also countries that have implemented a framework prior to the publication of the CEP.

Since independent aggregation needs to be implemented, countries that have considered the level playing field argument are relevant to consider.

#2

Question: Which model was chosen to facilitate independent aggregation?

Observations from other countries

All countries have implemented (or intend to implement) the central settlement model, except for Germany.

Germany has implemented the corrected model, a model that is also implemented in France (for > 36 kV connected customers) and in Belgium (for customers that perform the BRP role themselves).

Advantage of the corrected model, when applied to load curtailment (or demand-side generation management) is that:

- It sets the compensation price at the retail price, which is, according to the French regulator, the right level. In their evaluation, the German regulator also concluded that this is a reasonable price level, since it is based on competitive negotiations that market parties, supplier and consumer, agreed.[98]
- Low transaction costs as no price formula is required.[99]

There are two main methods to implement this model, either type A by manipulating meter readings (applied in France), or type B to separately register the activated volume without manipulating meter readings (applied in Germany).

Disadvantage of type A is that it may lead to legal issues, as customers pay for electricity that has not been delivered, or vice versa. When the corrected model is used for C&I customers (or large Industrial customers only), a second model is needed, at least for the residential sector, as we can see in France.

Type A method is also considered not feasible when energy costs and grid fees are combined on one customer bill. Grid fees should be based on actual (physical) consumption, even when these are listed separately on the bill, applying different meter readings, it will become apparent to the Supplier (issuing the bill) that an aggregator is active, thus distorting the level playing field.

98. https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/VortraegeVeranstaltungen/Aggregator_Modell_606.pdf?__blob=publicationFile&v=1
99. https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/VortraegeVeranstaltungen/Aggregator_Modell_606.pdf?__blob=publicationFile&v=1

Disadvantage of type B method is that confidentiality is not kept; the supplier is informed on the activated volumes per customer, as is the case in Germany. In this country, the need for disclosing the aggregator to the supplier is amplified by the requirement for the aggregator to exchange schedules with the customer's BRP.

Germany and Belgium are applying type B. For Belgium this option is only possible for customers that submit their own energy programs to their supplier, or they act as their own BRP. This is known as a pass-through contract and is the preferred model (by some aggregators) in terms of administrative burden.

Several countries (esp. Belgium and the Netherlands) prefer a contractual model to a regulated model in order to impose as less regulation as possible. The Belgian experience, where contractual models are the default option, and the central settlement model serves as a fall-back option, shows that the fall-back option is preferred by aggregators and suppliers. Most Belgian aggregators complain about the fact that they need to explore the contractual option first, since it is seen as an administrative burden to prove that they need to use central settlement as fall-back option. In France, however, the contractual model is the least preferred option, and it is not even allowed when the corrected model is applicable, due to the risk of unfair competition between incumbent suppliers and aggregator businesses and independent aggregators.

Based on aggregator's input, the main issue with supplier consent is not the supplier's intention to discourage aggregators entering the market, nor the issue of reaching an agreement on a transfer price. It is simply the hassle to negotiate with many suppliers, whereas suppliers are not accommodated for these specific arrangements, and discussions may take long as it is not seen as an important issue (small volumes).

Nordic Context

Energy costs and grid fees are combined on the same bill (although specified separately), except for very large industrial users
An initial legal assessment seems to suggest that in the Nordics, modifying meter values, e.g. by subtracting/adding activated flexibility volumes, and thus billing a different volume than the metered one, is generally not legal.

The large industrial players sometimes act as their own BRP or send their energy nominations to their supplier/BRP.

There are large industrial players that typically have their own balance responsibility, and are active offering DSR for some years, e.g. in Norway, Sweden, Finland.

The Nordic retail market is a fairly competitive market.

#3

Question: What should be the level of compensation / price formula?

Observations from other countries?

Looking at the experience of other countries we have seen that in general the compensation between aggregator and the supplier or BRP, if any, only covers the sourcing costs (or savings) of the supplier, any administrative costs are not covered. The exception to this is Germany, which also allows BRPs to decide whether they need to charge the aggregators for the so-called 'schedule exchange' as administration cost.

<u>Regarding transfer of energy price:</u>
In France, Germany and Belgium, when applying the corrected model, the transfer of energy price is set at the retail tariff.

For central settlement model, however, the price level needs to be set by regulation. While in Switzerland (for balancing products), and in the mFRR Finnish pilot, DA prices are used, in France and Belgium the regulator sets a formula.

In France, the formula principle for central settlement model is to approximate the retail price, and the NRA applies different approximations for profiled or telemetered sites, the latter being the one relevant for industry. For telemetered sites, the price is set at the forward market price for the trimester combined with the time (peak/off-peak) where the activation takes place, it also considers the possible arbitrage with forward prices and the ARENH (Regulated Access to the Historic Nuclear Power) price. Suppliers have complained that this formula, however, does not take into account the capacity mechanism prices. The CRE is adjusting the formula to include the capacity mechanism prices from 2023.

In Belgium, in addition to the French perspective, the regulator considers that the ToE price should not be fully known by either aggregator or supplier during bilateral negotiations but it should be fully known at the moment of activation. Also, CREG considers that not all energy is sourced in future markets, so a percentage of the price should correspond to day-ahead prices. Unlike the French regulator, the Belgian formula also tries to approximate the selling price of the supplier (not only the sourcing), which incorporates an asymmetric element depending on the type of activation, load en-hancement or generation curtailment.

In Great Britain, the ToE is currently 0 but the idea is to regulate it in the near future.

At the moment market players 'are not bothered' by it because there are very few activations.

Although a lower ToE price level may seem attractive to simulate the uptake of demand-side participation, none of the studied countries[100] considers lowering (or removing) the supplier compensation due to the negative consequences of setting the transfer price at 0 or too low:

- DSR may be activated that is not "in the money". If an aggregator can gain revenues on activating an asset that is not in the money, it will happen at the expense of another market player, typically the supplier of the customer.
- It will create a barrier for activation in the other direction (load enhancement / generation curtailment). In this case the supplier compensates the aggregator, if the price level is too low, flexibility that is "in the money" may not be activated.
- The level playing field on cross-border markets will be violated if the same technology faces different ToE price formulas based on different principles (i.e. different arbitrage options).

Nordic context

Although the Nordic market is fairly competitive, there are indications of suppliers having quite a profitable business leaving room for more efficient competition. Innovation is generally low, while price margins are relatively high.

Nordic industry energy tariff choice is fairly diverse. The larger industrial and commercial users are active in both day-ahead and the forward timeframes, either directly via their own trading desk, or indirectly via a portfolio manager (that offers access to the wholesale market to multiple customers). While most of these are exposed to day-ahead prices, the total exposure varies significantly. Smaller end-users are likely to act more similar to households in the respective countries, but we are not aware of any comprehensive overview of contracting behaviour.

Lessons learned

Countries that have only implemented ToE for balancing markets, have set the prices at the DA price, such as Switzerland and the Finnish pilot.

Countries that have implemented ToE for both balancing and wholesale, have chosen the same ToE price formula for both markets. In this case, the DA price is not a suitable option.

Countries that have implemented the ToE for balancing and wholesale (France and Belgium) have considered the prices of forward energy markets, complemented (in the case of Belgium) by day-ahead prices.

France and Belgium try to set ToE price level to be representative of the supplier's sourcing cost of electricity which are a proxy for retail tariffs, particularly for the C&I

100. GB may be considered the only exception, yet this is considered as a temporary solution until a permanent solution, esp. suitable for wholesale markets, has been put in place.

sector. In Belgium, the supplier 'estimated' margin is also accounted for, unlike France.

This does not lead to large differences, as supplier margins are relatively low.

All of the ToE price formulas have a temporal element, e.g. seasonal, time of the day, peak/off-peak.

Setting the ToE to DA price is a 'practical and logical' solution for balancing services according to some aggregators. However, this is hardly the case for ToE in ID markets and not an option for DA markets. CREG argues that giving too much weight on the DA price element does not realistically reflect the sourcing strategy of the supplier. In the Nordic countries, the balance between future and DA markets should be assessed per country since the retail tariffs are significantly different among countries, and thus the sourcing strategy would vary.

Given the difference in retail tariffs, if the Nordics were to harmonise a ToE formula, the price level per country could be different. The price formula, however, can still be harmonised.

Most industrial aggregators are not concerned with the ToE price, they normally man-age assets with very high activation costs, which makes the ToE price negligible, and that are activated infrequently. This would also be the case in Finland for reserve and capacity products like strategic reserves in Finland.

In France, where activations are more frequent in the wholesale markets, suppliers are actively discussing the ToE topic. Whereas in the rest of the countries it does not seem to be a point of interest.

Other costs, other than sourcing costs, might be relevant to include; such as capacity and balancing costs, that are normally included in the retail tariff.

Few aggregators, especially within the residential sector, have argued that this compensation should not be paid by the aggregator because it would be detrimental to their business case, while the overall effect of demand response would be positive for society. However, this argument did not convince regulators, in particular the German NRA, due to the market distortion argument.

#4

Question: Is the uncorrected model applied? For which products?

Observations from other countries

The uncorrected model has been implemented by all analysed countries. This model is usually the first one to be adopted to allow independent aggregation participation since it does not require any fundamental changes.

This model is typically used in products that only have capacity payments, involve low energy activation volumes and/or are symmetrical, which would result in a (close to) net 0 energy consumption.

In the Netherlands, Belgium, Switzerland and Germany, this model is used for the FCR product. In France, next to the FCR product, aFRR also uses an uncorrected model, since this product is symmetrical at the moment, and there is little to no participation from aggregators.

In Great Britain, the uncorrected model is still in use for some balancing products and the capacity mechanism.

Finally, in Finland, the uncorrected model is applicable for FCR-D. Although FCR-D is not symmetrical, it is rarely activated (approximately 3% of the time).

Nordic context

The Nordic countries have two different FCR products: FCR-N and FCR-D.

The uncorrected model for the FCR-D product is already applied in Finland. Whereas for FCR-N, Fingrid applies a central settlement model.

Lessons learned

The learnings from other countries are applicable in the Nordics for their FCR products. For FCR-D, the learnings are limited to the experience of Finland, which have proven that the energy activations of these products are rare and therefore introducing a more complex model may not justifiable due to proportionality.

#5

Question: Do independent aggregators already have access to wholesale markets?

Observations from other countries

Only France and Belgium (recently) allow independent aggregators access to wholesale markets. Since an independent aggregator needs to source its energy through the ToE, a ToE mechanism is a prerequisite to enter this market. Both Belgium (starting 2025) and France have a capacity market (capacity remuneration mechanism) in place, where activation is organised through the wholesale market. As a consequence, access to wholesale markets is a prerequisite for independent aggregators to be active in these capacity markets.

Several regulators seem to struggle with wholesale market access. Independent aggregators, typically active in explicit products such as balancing (and in the future – potentially – congestion management), have access to flexible resources that also may prove valuable on wholesale markets, especially when volatility and price spikes increase. Some further observations:

- The business models of most aggregators today, focus on products with capacity payments. In terms of priority, allowing access to balancing products seems more relevant than access to wholesale markets (although in Germany some aggregators are active in wholesale markets, albeit (until today) through a contractual model).
- Allowing customers access to wholesale market can easily be achieved, by applying dynamic tariffs that reflect wholesale prices. In this model, aggregators can still provide services to the customer by optimising their load/generation profiles, yet they will not be an active market participant in such a model. In other words, especially in the absence of capacity mechanisms, imperfection of retail tariffs is the only justification to implement independent aggregation in wholesale markets.
- At the same time, it is important to notice that many customers are reluctant to be exposed to variable wholesale prices, and prefer fixed prices that are agreed months or years in advance (although this differs strongly from country to country). With the increasing volatility in wholesale prices, they could still increase system efficiency by offering their flexibility, e.g. through an independent aggregator.
- The obligation to allow customers to select multiple suppliers, and the efforts in several countries to remove financial and administrative barriers for doing so,

would allow customers to only expose their flexible assets to wholesale prices, therefore this development can further reduce (but not remove) the need for independent aggregation in wholesale markets.

- When allowing independent aggregators access to wholesale markets, the right choice for the ToE price formula becomes even more delicate. This is further explained in the section on the residential segment, where this is the most relevant.

Nordic Context

There are no capacity mechanisms within the market (Finnish and Swedish strategic reserves are outside the market).

It is DNV's understanding that C&I are better hedged than households – higher shares of fixed price contracts, and larger DA exposure in Norway and Sweden than Finland and Denmark.

There is a strong focus in the Nordics to remove barriers for so-called split-responsibility models.

Lessons learned

Allowing access to wholesale markets is more complicated than access to balancing products. For customers with (an appetite for) dynamic contracts, an aggregator can provide its services directly to the customer, without supplier consent (but not as an active market player). Facilitating this access may still be needed for customers with fixed energy tariffs (which may be more relevant to e.g. Norway than Denmark), and (possibly) in the future when capacity mechanisms are introduced. The framework for wholesale markets can be similar to balancing products, although setting the right ToE price formula may be even more delicate, and baseline design and monitoring are also far more complicated compared to balancing products.

#6

Question: What are important factors for aggregators to enter (national) markets?

Observations from other countries

Main factors, as indicated by aggregators:

- A regulatory framework in place that does not require interaction with the supplier
- Products that target demand side flexibility, or at least are sufficiently attractive, both in terms of product design (i.e. no undue barriers) and profitability – as seen in some products in France, Belgium, GB, Germany
- Products with capacity payments and low activation frequency (capacity markets, mFRR) – as seen in Belgium, Germany, GB and Finland
- Subsidy schemes for demand-side participation, as seen in France. Sufficiently high revenues, either from high balancing prices or high volatility in wholesale prices.
- Sufficiently large markets.

Nordic context

- Nordic countries have in general lower flexibility needs compared to other European countries, due to hydro energy and interconnectors.
- Product design still seems to be focused on the generators.
- Aggregator regulatory framework is not there yet, except for some products in Finland.
- There are no subsidy schemes to encourage demand-side participation.
- Although there are products that provide capacity payments, they are limited to balancing services, except for Finland and Sweden where there is a strategic reserve product.

Lessons learned

The main applicable lessons for the Nordics are:

- To implement a regulatory framework to enable independent aggregation
- To reconsider their product design: pre-qualification, baseline, payment, bid size, validation, data exchange requirements, etc.
- Subsidy schemes could be considered if there is real need for demand-side

participation to be active in the market, and the business case of the aggregator is not positive with the current prices, especially at the start (CAPEX intensive period).

#7

Question: How is rebound handled?

Observations from other countries

There is little experience from the studied countries. In France, the rebound effect was studied but it was determined that the rebound effect will not impact the payment by the aggregator to the supplier because the supplier still provided the energy, so they should be remunerated for it by the customer. Potential imbalances that the rebound may have in the BRP's portfolio are however not being accounted for at the moment. For now, none of the countries have provisions on compensation of the rebound to the supplier.

Nordic context

Rebound effect is strongly depending on the type of technology (e.g. emergency gen sets have 0% rebound, EV charging 100%). The Nordic context can be described by the technologies that future independent aggregators will operate in the Nordic markets, which is unknown.

Lessons learned

There are no best practices how to handle the rebound effect, other than simply ignoring the possible impact on the supplier.

Three main reasons why the rebound effect, until today, has not been included in the compensation mechanisms:

- Any solution will be highly depending on the technology (asset type) involved, and is therefore likely to be very complex and difficult to justify;
- Current DSR (activated) volumes are relatively low and, consequently, so are the rebound volumes.
- Current technologies used are mainly located in the industrial sector, where the rebound effect in several cases might be negligible due to:
    - Continuous operation: industry might be operating continuously and therefore, after a flexibility activation they will continue production as usual, without increasing the demand (compared to usual operation)
    - Fuel-switch or generation turn-up: the flexibility might be coming from a back-up generator, or CHP, and therefore no rebound will occur.

#8

Question: What kind of IT systems are used to facilitate (independent) aggregation?

Observations from other countries

Several countries are moving towards IT systems to lower barriers for distributed flexibility participation in markets and to lower TSO effort, realising that scalability is hardly possible without automation.

Switzerland, the Netherlands and part of Germany are piloting Equigy Crowd Balancing platform. This is still not part of BaU for Swissgrid, but TenneT is already using it, as one of the alternatives that BSPs have to transfer data. TenneT still relies on other systems for BRP perimeter correction.

In Belgium, the existing data hub for DSOs, Atrias, is now developing into a central market system platform that will facilitate the access of distributed flexibility into the market.

In France, and Great Britain, RTE and ELEXON have developed their proprietary systems for communication exchange and settlement.

Germany does not have a platform/data hub for flexibility transactions.

Nordic context

The Nordics are developing joint initiatives like eSett, for imbalance settlement. Data-hubs however are not harmonised and the NordREG recently concluded that making data hubs interoperable would not be cost effective compared to the benefits.[101]

Lessons learned

As country experience proved during operation and piloting, a system to register flexibility transaction and/or data exchange would:

- Lower the barriers for new entrants
- Facilitate the work for the TSO or the ISR when correcting perimeters, validating flex delivery and performing settlement
- Make the model scalable

Each country has developed their platforms / data hubs for facilitating independent

101. Implement Consulting Group - Nordic Data Hub Interoperability (nordicenergyregulators.org)

aggregation in isolation, providing no experience relevant to Nordic platform harmonization.

3.2 Residential

Before addressing specific elements for the residential sector, first some observations are made about best practices and about the main differences between the residential and C&I sector.

Experiences with (explicit) flexibility in general, and independent aggregation specifically, are very limited.

In general, we conclude that experiences are too limited, to draw any solid conclusions that could inform policy makers in the Nordics. What we have observed:

- Only France, Switzerland and Finland have a regulatory framework in place allowing access to residential flexibility through independent aggregators applying the uncorrected and central settlement model
- In Switzerland and Finland access is limited to balancing products
- In France access is limited to demand turn-down (generation enhancement), whereas residential flexibility is also well-suited to absorb renewable energy such as EV charging or electric heating when prices are low.
- Only very few aggregators are active in these countries in this sector. They are still facing difficult market conditions and challenging business cases and are potentially still loss-making.

Characteristics of residential flexibility and industrial flexibility are fundamentally different, which may lead to different choices when implementing a regulatory framework.

Industrial Flexibility

- Demand-side participation is well established, although in most markets still a niche activity.
- Regulatory framework in place for Ger, Fra, Bel, Swi and in development for NL, GB and Fin
- Characterized by large volumes (power) per customer, typically high activation costs and low activation frequencies
- Compensation and ToE price level is therefore less of an issue
- Mainly load shedding and generation management
- Some barriers exist, e.g. grid tariffs

Residential flexibikity

- Only significant demand-side participation from independent aggregators in France and, to some extent, Switzerland and Finland
- Regulatory framework in place only for France, Switzerland and Finland; in development for Belgium.
- Characterized by small volumes (power) per customer, typically low activation costs and high activation frequencies
- Compensation and ToE price level is therefore crucial
- Mainly load shifting
- Several barriers exist, e.g. lack of smart meters, lack of smart meter allocation, use of standard load profiles

Figure 15. Main differences between residential and industrial flexibility

The main differences are shown in the figure above. This is a simplification, as some types of "cheap" flexibility can also be found within Industry; this is expected to develop further when industrial heat demand is electrified. However, it largely represents the current status quo, where industrial DSR is mainly active in adequacy mechanisms and capacity products such as STOR in Great Britain, mFFR-da ("noodvermogen") in the Netherlands and interruptible loads AblaV in Germany. These differences, in general, complicate matters when developing a regulatory framework for independent aggregation in the residential sector; for example with respect to baseline design, compensation, transfer of energy price or rebound.

Baseline design, especially for the Transfer of Energy in wholesale trading
Baselines need to represent the counterfactual, i.e. the load pattern that would have occurred under normal circumstances, without DSR activation. Typical baselines for wholesale markets are based on historical load profiles, under normal conditions. This becomes complicated when this flexibility is activated or optimised on a daily basis, and the exceptional DSR activation becomes the norm.

Compensation, ToE price and rebound
Compensation from the supplier's perspective is a neutralization of the sourcing

costs which includes potential imbalance costs. However, from the independent aggregator's perspective, it is the basis for arbitrage as the sourcing cost for an aggregator consists of the marginal costs for activation by the customer (e.g. value of loss load, fuel costs) and is increased by the costs for the compensation or Transfer of Energy. Residential flexibility, contrary to Industrial flexibility, typically consists of time-shifters and storage facilities, characterised by low-to-zero marginal costs. For instance, marginal costs of pre-heating and batteries are limited to energy losses; marginal costs of (shifting) EV charging may be 0 – although revenues may be shared with the customer.

For efficient market functioning, it's not only important that load is reduced during peak hours, but also that the load is shifted to off-peak hours. For example, if the evening peak occurs between 17:00h and 19:00h, an aggregator can generate revenue by reducing the total load of an EV-charging portfolio from 17:00 to 18:00. If that load is fully shifted to the next hour, the peak in that hour is only aggravated.

From a market perspective, a shift is only valuable if the rebound occurs in a period with lower prices. Since in the studied models, rebound is not taken into account, the aggregator only needs to compare the ToE price with the wholesale price, and does not need to consider the rebound. Although the Aggregator can often (technically) control it – and even could generate revenue when wholesale off-peak prices are lower than the ToE price. The only relevant model (France) has not solved this conundrum yet, possible solutions likely require NEBEF to support load enhancement next to load curtailment.

The main lesson learned is that the ToE mechanism should be symmetrical. If this does not provide sufficient incentives for an aggregator to control the rebound, additional regulations are needed with respect to compensation and rebound.

Tromsø, Norway

4. CONCLUSIONS

The Electricity Market Directive (2019/944) is not yet fully transposed into national legislation, but this is essentially a matter of time. The Directive lays out requirements and suggestions ("may") on how market participants engaged in aggregation and independent aggregators should be integrated into the electricity market, especially in Article 17.

Our study has focused on the requirements to enable demand side participation and, in particular, on the participation of aggregated loads. It becomes apparent that implementing these requirements is far from trivial, therefore studying implementations in different member states that have advanced this topic is highly relevant, whilst acknowledging certain differences between the member states. In this study we have analysed implementations and current developments in Belgium, Finland, France, Germany, Great Britain, the Netherlands and Switzerland.

4.1 Differences observed in analysed countries

Although the timing and triggers for implementing a regulatory framework for independent aggregation differs from country to country, many similarities on the principles can be observed, that are also applicable to the Nordics:

- All frameworks need to comply with the Electricity market directive (also frameworks designed before the publication of the CEP are not conflicting with the directive[102], although possibly not covering all services – e.g. Switzerland does not support access to wholesale markets)
- All frameworks need to be consistent with the Electricity Balancing Guideline
- All frameworks intend to take market considerations and efficiency into account; on the one hand, attempting to create a level playing field for aggregators and on the other hand avoiding market distortions. In our analysis, Germany has prioritized the latter over the former and has not achieved a full level playing field.

Given these strong similarities in principles, we conclude that experiences and best practices from other countries are relevant to consider. At the same time, experiences in the residential sector specifically, and to a lesser extent, wholesale trading, are very limited.

Although principles are similar, there are also differences between the countries

102. Based on DNV analysis rather than a legal assessment

when it comes to design choices, which are sometimes significant. Despite these differences, we still observe strong similarities in those design choices. These are highlighted in the table below.

Strong similarities	Limited differences	Substantial differences
Aggregation model	Level of compensation	IT systems to facilitate independent aggregation
Use of uncorrected model	Access to wholesale markets	
Rebound	Balance responsibility	

Table 8. Differences in design choices per topic

Differences in design choices can often be traced back to country-specific conditions. The table below shows a summary of findings from our study on these differences, and connects these to conditions in the Nordic countries.

Topic	Main differences observed	Conditions in studied countries	Conditions in Nordics
Level of compensation	• Switzerland uses DA prices • Finland uses balancing price for FCR-N • France and Belgium: differences in price formula	• Switzerland: no access to wholesale, the compensation only applies to aFRR and mFRR • Finland: the compensation applies to FCR-N • France/Belgium: different sourcing costs for Supplier	• Allowing access to wholesale markets is a point for discussion in all Nordic countries. • Sourcing costs are not fundamentally different given the tight market integration, although cost levels could be different (even within a country).
Access to wholesale markets*	Only implemented in France and Belgium**	France and Belgium have capacity mechanism (through market)	No capacity mechanism (through market). Strategic reserves in Finland and Sweden.
Balance responsibility	Belgium and Finland (trial) require IA-BSP to conduct / assign BRP role, other countries don't	Differences is caused by differences in implementing the BSP role (EBGL)	Implementation of BSP role has not been finalized.
IT systems to facilitate independent aggregation	Large differences in IT systems used, mostly proprietary systems.	Strong interdependency with systems used for wholesale settlement, which is different in all countries.	All Nordic countries except Iceland use common wholesale settlement platform (eSett)

*This difference can also be considered as a difference in timing, rather than in design
**German implementation also allows access to wholesale markets; not shown here as this still requires an agreement between Aggregator and Supplier

Table 9. Main causes for observed differences

The table shows that most of the causes that have led to different design choices are not applicable to the Nordics. However, a key take-away is that to harmonise the Nordic approach, it is important is to agree on certain common design principles:

- Consistency with respect to the implementation of the BSP role – a common view on whether an aggregator's balancing responsibility is limited to just a financial responsibility, or should be extended to performing or outsourcing the BRP role.
- Agreement on the compensation formula.
- Agreement on the timing and principles for allowing independent aggregation access to wholesale markets.

4.2 Main lessons learned

Section 4 includes a summary of the lessons learned from the implementation in other European countries.

The table below summarizes the main findings common to most, if not all countries.

Topic	Commonalities
Aggregation model	All countries studied, except Germany, have a form of central settlement model in place (France and Belgium have also implemented a corrected model)
Use of uncorrected model	All countries use an uncorrected model for certain products, typically capacity-only products or capacity products with a small energy component such as FCR.
Rebound	None of the countries have taken rebound into account in relation to the open balancing and/or sourcing position (i.e. compensation) yet.
Level of compensation	All countries have implemented/plan to implement a compensation payment between the independent aggregator and supplier. Most countries set the compensation at (an approximation of) the retail tariff level (excluding taxes and network tariffs) or at the level of the sourcing costs, both leading to similar price levels.
Access to wholesale markets	Most countries seem to struggle with implementing this aspect. Belgium has implemented it, yet there is no practical experience gained yet. France has implemented it, yet only for demand turn-down, and with quite some restrictions (e.g. strict requirements on baselines).
Balance responsibility	All independent aggregators need to be or be assigned a BRP to be active in the wholesale market. For balancing services, all independent aggregators bear financial balance responsibility, at least for under-delivery. Different regulations can be observed with respect to over-delivery.

Table 10. Main commonalities found on independent aggregator regulatory framework implementation on the different countries.

Appendix A: Definitions

Adequacy	General meaning: the state or quality of being adequate; sufficiency for a particular purpose. Specific in energy markets: whether the generation capacity is sufficient to meet the demand. http://www.dictionary.com/browse/adequacy?s=t
Adequacy product	Product that is intended to increase the adequacy of the system. It is one of the possible flexibility products.
Allocation	Allocation of measured energy consumption in a certain control area to the different BRPs.
Ancillary and balancing services	Ancillary and balancing services refer to a range of functions which TSOs contract so that they can guarantee system security. These include black start capability (the ability to restart a grid following a blackout); frequency response (to maintain system frequency with automatic and very fast responses); fast reserve (which can provide additional energy when needed); the provision of reactive power and various other services. https://www.entsoe.eu/about-entso-e/market/balancing-and-ancillary-services-markets/Pages/default.aspx
Arbitrage	In economics and finance, *arbitrage* is the practice of taking advantage of a price difference between two or more markets: striking a combination of matching deals that capitalize upon the imbalance, the profit being the difference between the market prices. https://en.wikipedia.org/wiki/Arbitrage
Balancing	The act of reducing/increasing load/generation by a BRP in an attempt to restore its portfolio imbalance. Similarly, the act of reducing/increasing load/generation by a TSO in an attempt to restore the system imbalance. In the latter case, the TSO uses balancing services for this purpose. Balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply, in and near real time. https://www.entsoe.eu/about-entso-e/market/balancing-and-ancillary-services-markets/Pages/default.aspx
Baseline	It is the best approximation of the energy consumption or production that would have occurred, if no DR event would have been triggered. Used to quantify the delivered flexibility.
Contracted bidding	The acts of placing bids on a market which was committed beforehand via a (contractual) obligation. This is a way for the contracting party to ensure certain market volume. Opposite of free bidding.
DER	Distributed Energy Resource
Dispatch	Turn on or off a power generation unit or adjust their power output according to an order. Dispatching of a generation unit is generally at the request of power grid operators or of the plant owner to meet the demand in the power system, and based on the merit-order. Opposite of intermittent energy sources. https://en.wikipedia.org/wiki/Dispatchable_generation

Ex-ante	The term ***ex-ante*** is a phrase meaning "before the event".[1] *Ex-ante* is used most commonly in the commercial world, where results of a particular action, or series of actions, are forecast in advance (or intended). The opposite of ex-ante is *ex-post* (actual). https://en.wikipedia.org/wiki/Ex-ante
Explicit distributed flexibility	Form of flexibility where customers makes an explicit change in demand/generation in response to a signal, and is specifically rewarded (remunerated) for that change.
Ex-post	"Afterward", "after the event". Based on knowledge of the past. Measure of past performance. https://en.wikipedia.org/wiki/Ex-post
Ex-post nomination	The possibility for BRPs to include transactions after the Operation phase (i.e. after the associated ISP) by a change in their approved E-programs. This changed is processed by the TSO before the allocation. Via this mechanism BRPs can mutually settle imbalances and avoiding the imbalance penalties raised by the TSO.
Flexibility service quantification	Determination of the amount of load/generation reduction/increase in terms of instantaneous power [W] or energy during a certain time interval [Wh]. To determine whether the service was actually delivered with the right quantity. A *baseline* is needed for this purpose.
Free bidding	The act of placing bids on a market without a (contractual) obligation to do so. Opposite of contracted bidding.
Gaming	Using the rules and procedures meant to protect a system in order, instead, to manipulate the system for a desired outcome. Gaming is a form of abuse. See also *arbitrage*.
Grid	Network for the transport and distribution of energy.
Implicit distributed flexibility	Situation where customers are exposed to varying energy prices and/or grid tariffs and respond by adapting their energy demand profile. In general, consumers exposed to such tariffs might have an automated system or a 3rd-party (ESCO) service that helps them to consume their energy at optimal prices.
Merit-order	The merit order is a way of ranking available sources of energy, especially electrical generation, based on ascending order of price (which may reflect the order of their short-run marginal costs of production) together with amount of energy that will be generated. In a centralized management, the ranking is so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought on-line. Dispatching generation in this way minimizes the cost of production of electricity. Sometimes generating units must be started out of merit order, due to transmission congestion, system reliability or other reasons. https://en.wikipedia.org/wiki/Merit_order
Nomination	The act of informing the counterparty about the forecasted energy profile for the near future. For example, a day-ahead nomination for the full next day, an intra-day nomination for the remainder of the day or short-term nomination for one or more ISPs.
Notification	Activation request by the system operator towards the flexibility service provider. In case of wholesale trading: closure of wholesale trade.
Passive balancing	A BRP helps reduce the imbalance for the whole control area by deviating from its own electricity program. If this contributes to reducing the total imbalance, the BRP may receive remuneration for its passive contribution, depending on market design.

Perimeter correction	Adjustment of the imbalance volume of the corresponding BRP. Normally performed by the ISR role to avoid that flexibility activation would result in an imbalance due to the changed energy volume.
Rebound effect	The phenomenon that the load reduction (or increase) triggered by a demand response event, is compensated partly or fully outside the activation period or by other resources.
Redispatch	The act to compensate a demand/generation increase/reduction of an asset by an opposite change at another asset within the same portfolio or region such that the remaining profile at portfolio level or region level remains constant. This mechanism is sometimes used to solve grid congestion issues.
Resolution	The resolution of a flexibility product refers to the time intervals of the measure load/generation profile which should also align with the resolution of the baseline.
Service window	Time of the year/week/day that a certain service is active (e.g. strategic reserves are typically limited to the winter period).
Settlement	Determining the energy production and consumption and used flexibility as preparation for the billing process.
Sourcing (of energy)	Purchasing of energy.
Spot Market	A spot market or is a public financial market in which financial instruments or commodities are traded for immediate delivery. Day-ahead markets and intra-day markets are both spot markets. https://en.wikipedia.org/wiki/Spot_market
Transfer of Energy	Energy volumes transferred between the BRP of the Aggregator and the BRP of the Supplier. In this text the Transfer of Energy is used to compensate the BRP of the Supplier for the effects of flexibility activation by an Aggregator, and to source the energy associated with this activation.

About this publication

The regulation of independent aggregators with a focus on compensation mechanisms

A team from DNV: Aurora Sáez Armenteros, Hans de Heer, Jørgen Bjørndalen

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