# INDEPENDENT AGGREGATOR MODELS

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# EXECUTIVE SUMMARY

*Background and objectives*

Pöyry was commissioned to conduct a study for evaluating different independent demand-side response (DSR) aggregator models by the Energy Authority (Energiavirasto) and Fingrid Oyj.

The European Commission's proposal for a revised electricity Directive, published with Clean Energy Package[1], states that the role of independent aggregator should be introduced in European electricity markets. An independent aggregator is defined as a market participant that performs demand-side aggregation that is not affiliated to its customers' suppliers. The independent aggregator is not a balance responsible party (BRP) of its customer's electricity supply and is not obliged to contract or co-operate with the BRPs whose customers' flexible demand is aggregated.

The objective of the study was to define the most suitable independent aggregator model for different market places in Finland. The study focused on the distributional effects of different models on stakeholder groups: customers, suppliers and BRPs, aggregators, the transmission system operator (TSO) and other balancing service providers. In addition, the wider impacts on electricity markets and market prices were analysed as well as technological and regulative aspects.

The following models, with different approaches to imbalance correction and compensation, were analysed:

- Model A: Imbalance volume correction with no compensation
  - The BRP's imbalance volumes are corrected based on the demand-side response that was activated by the independent aggregator. There is no compensation paid to the BRP by any market participant.
- Model B: No imbalance volume correction or compensation
  - There is no correction of imbalance volumes and the BRP is effectively compensated through the imbalance settlement.
- Model C: Imbalance volume correction and compensation
  - The BRP's imbalance volumes are corrected similar to model A. In addition, BRP is compensated by the aggregator at a predefined reference price.

At the moment, models B and C are applied in some of the market places in Finland. In addition a fourth model, based on multiple suppliers, was analysed but was considered not to be feasible for implementation in the short term.

*Our analysis indicates that model C with imbalance volume correction and compensation is the most neutral of the models, provided that issues related to imbalance settlement are tackled*

The evaluation of the different models can be summarised as follows:

- In model A the customer's supplier faces the highest risk for increased procurement costs of the analysed models. This could then lead to a situation where the additional imbalance costs are charged to the customer through higher retail prices. If retail prices increase, customers would require a higher share of revenues from any DSR activity and thus lower the value to the aggregator.
  - In the longer-term this could lead to a shift in relative attractiveness of customer groups to suppliers. The 'traditional' suppliers would compete more strongly in less flexible segments of the market because they cannot bear the risk in the flexible part, so prices would start to go up for the flexible customers and/or aggregators would end up having to become more like traditional suppliers.

[1] European Commission, Clean Energy for All Europeans, November 30th 2016. Available at: https://tinyurl.com/j6fdcmg

- Model B has the most benefits for the customer participating in demand-side response through an independent aggregator, but leads to highest additional costs which are socialised to all market participants.
  - The marginal cost for the independent aggregator to provide demand response is lower than if it were offered by the supplier, although the physical resource is the same. This means that the aggregator is not competing on equal terms with other balance service providers. This could lead to a situation where cheapest resources are not activated.
  - There is also a risk that this could lead to situations where it is more profitable for the balance responsible parties to offer demand-side flexibility through the independent aggregator model. This is because they would receive the benefit both from selling balancing services and selling the surplus back to the TSO through the imbalance settlement, if there is no regulation in place restricting the possibility for arbitrage.
- Model C has the least distributional effect to the customer's supplier through increased imbalance costs; other BRPs through increased balance service fees; and other balance service providers through unequal competitive position.
  - Model C could have the biggest direct implications for the TSO as they would be responsible for the re-allocation of imbalance volumes and administering the process for the compensation payments.

*The characteristics of the Nordic wholesale and the Finnish retail markets support the choice of Model C in most markets, with the exception of disturbance reserves*

In models A and B, independent aggregation would result in a cost that would have to be transferred to the customer's BRP (model A) or all BRPs (model B). The basis for this cost is to bring more DSR to the market. The characteristics of the Finnish market support the choice of model C, namely:

- There is already active demand-side response from heavy industry in the Finnish market.
- Hourly, and in the future 15-min, metering enables dynamic tariffs for retail customers allowing them to respond to wholesale prices.
- The Nordic wholesale market and the Finnish retail market are generally considered competitive.
- There are no explicit barriers to entry for aggregated demand-side response in different market places and the Finnish TSO is active in piloting new technologies and updating market rules to accommodate these technologies.
- The extra cost for demand-side response is in conflict with the energy-only principle of the Nordic market and can have a negative longer-term impact on investment if scarcity is not reflected in the energy prices, i.e. the marginal cost of all actions required to meet demand for reliable energy.

The argument for pursuing other models (such as Model B) would need to be based on a decision that there is a considerable need for DSR and that consequences such as socialisation of costs and potential second order effects are seen as acceptable. Still, if there is political will to develop DSR (i.e. societal benefits outweigh costs), this can be done through other means that would have less of a market distortion than Model B. Such approaches could include e.g. direct investment and innovation support. This type of approach would also reduce the risk for investments in DSR capabilities. This is especially important for smaller scale customers where electricity procurement is only one of the cost items. Stakeholder interviews indicated that customers typically require short payback periods, e.g. 1 year, for investments in DSR.

The recommendations for different market places are summarised in the table below.

| Markets | Recommendation | Reasoning |
|---|---|---|
| Day-ahead market | Model C | ▪ The easiest way for retail customers to participate in the day-ahead market is to have a dynamic contract based on hourly wholesale prices.<br>▪ If customers react to prices, over timer suppliers should adjust their demand forecast models* and procure volumes at different price levels, resulting in the market clearing at lower volumes and prices. |
| aFRR, mFRR and intraday | Model C | ▪ The basic principle is the same in all these markets: benefit from demand-side flexibility is based on the spread between day-ahead and intraday/balancing prices.<br>▪ aFRR and mFRR are TSO markets, and the metering data provided to the TSO can be used to allocate the volumes and compensation to different BRPs. The verification and compensation process is currently being piloted by Fingrid and the lessons learned during the pilots should feed into the detailed design of the re-allocation and compensation process.<br>▪ The verification process used in the balancing markets could be extended to apply in the intraday market as well in the case of independent aggregation. |
| FCR | Model B (FCR-D)<br>Model C (FCR-N) | ▪ Most or all of the compensation is based on capacity payments so model impact is limited.<br>▪ Model B is already in use for FCR-D and it is activated so rarely that the impact on BRPs is very minor.<br>▪ In case of FCR-N, the energy compensation is already allocated to the BRPs and the aggregator gets to keep the capacity payment. The analysis also indicates that the impact on BRPs is likely to be minor in any case. |

* In the Finnish market all customers are hourly settled based on the metered consumption. This means that the procurement by suppliers is based on hourly demand forecasts instead of fixed profiles with forecasts for monthly or annual consumption.

# 1. INTRODUCTION

## 1.1 Background and objectives

Pöyry was commissioned to conduct a study on different independent demand-side response (DSR) aggregator models by the Energy Authority (Energiavirasto) and Fingrid Oyj. This was in light of the changing power system in the Nordics and the proposals in the Clean Energy Package of the European Commission. The study relates to the work of the Finnish Smart Grid working group[2] (established by the Ministry of Economic Affairs and Employment).

A demand-side aggregator contracts with individual demand sites (industrial, commercial or residential customers) and aggregates them together to operate as a single DSR resource.

The European Commission's proposal for a revised electricity Directive, published with Clean Energy Package[3], refers that the role of independent aggregator should be introduced in European electricity markets. An independent aggregator means a market participant that performs aggregation that is not affiliated to its customer's supplier. The independent aggregator is not a balance responsible party (BRP) of its customer's electricity supply or not obliged to contract or co-operate with the BRPs whose customers' flexible demand is aggregated.

Introduction of independent aggregator role has been seen as one way to improve the efficiency of the electricity system by facilitating demand-side response, energy efficiency and automation of electricity consumption in general, e.g. by:

- avoiding or shifting consumption to reduce peak demands;
- increasing the consumption during hours of low electricity price; and
- providing balancing services and increasing security of supply.

In addition to DSR aggregation, it is also possible to aggregate small-scale production and storages, but DSR aggregation is more complicated as the energy is usually bought beforehand and therefore this study focuses on DSR aggregation.

In addition, the independent aggregation model increases the offering of DSR services for the end users and increases the competition in the DSR service markets. The discussion related to independent aggregators is also about equal and fair treatment of different stakeholders in the electricity markets. The key issues are the relationships and share of responsibilities between customers, aggregators, suppliers and BRPs:

- How should the risk management between market participants be arranged?
- Should an independent aggregator be obliged to compensate other market participants for the consequences caused by the change in the customers' energy demand?
- What are the obligations and responsibilities of an independent aggregator?

The objective of the study is to define the most suitable independent aggregator model for different market places (day-ahead market, intraday market, balancing market and reserves)**.** The study focuses on the distributional effects on different stakeholders, which is done by analysing different independent aggregator models in terms of cash flows and financial impacts on customers, suppliers and BRPs, aggregators, and other balancing service providers (BSP). Dynamic effects, which are not part of the financial impact assessment, are then analysed qualitatively. These include issues such as:

- value of flexibility in the system and cost of providing demand-side flexibility;
- the increase in provision of demand-side flexibility in the different of models;

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[2] For further information, see: http://tem.fi/alyverkot

[3] European Commission, Clean Energy for All Europeans, November 30th 2016. Available at: https://tinyurl.com/j6fdcmg

- impact of DSR on market prices and reduced need for generation or network investments in the long term;
- impact on market participant behaviour, such as suppliers changing their approach to pricing and risk management or becoming aggregators themselves; and

In addition, the study looks at requirements for information exchange and metering to implement the different models.

## 1.2 Structure of this report

Chapter 2 contains a description of a future scenario of the operating environment in 2025 in the Finnish electricity markets. This is a combination of expected changes in market fundamentals and market design. The future scenario is defined in order to identify relevant changes in the business environment that might have an impact on longer-term suitability of different aggregator models.

Chapter 3 contains descriptions of the different independent aggregator models and analysed market places.

Chapter 4 describes the approach and assumptions used in the study.

Chapter 5 contains the evaluation of different independent aggregator models. The financial impact assessment for different stakeholders is conducted as a desktop analysis based on historical electricity market data. In addition, the impacts on electricity markets and DSR business potential are assessed. The chapter ends with a regulatory and technological review on proposed independent aggregator models. Eight stakeholders – suppliers, balance responsible and aggregators – were interviewed in order to better understand the perspectives of different market participants.

Chapter 6 contains the conclusions and recommendations from the study.

# 2. OPERATING ENVIRONMENT IN 2025

This chapter describes the expected development of the operating environment by 2025. The future scenario provides context for the evaluation of different models to account for adaptability in a changing environment.

## 2.1 Electricity market fundamentals

### *2.1.1 Demand in Finland*

The demand of electricity is estimated to increase roughly 6 TWh by 2025[4] (Figure 2-1). Even though the economic growth would mean growth on industry and service sectors, the increasing energy efficiency decreases the demand.

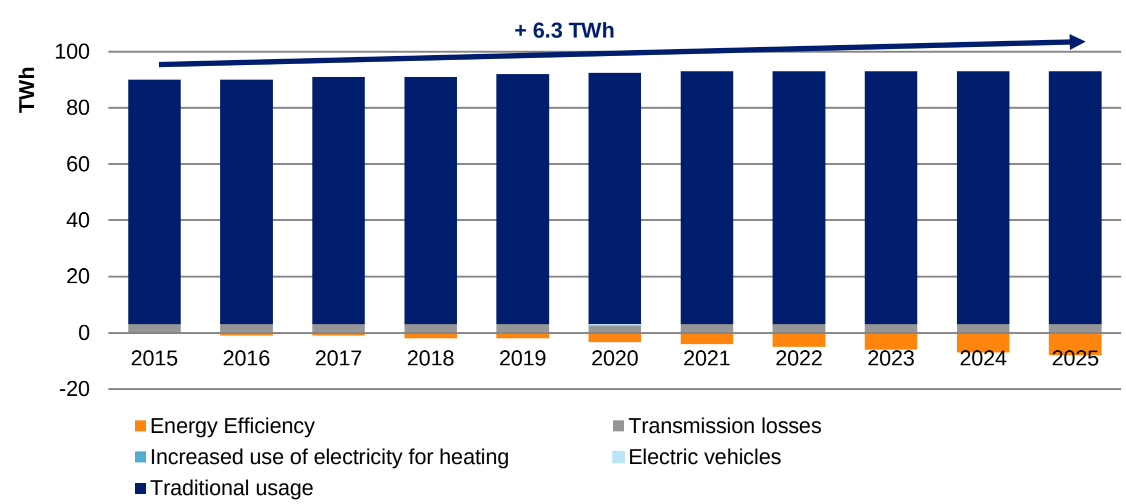
According to the study[3], demand is expected increase mainly due to:

- increased amount of electricity for heating;
- increase in usage of electric devices;
- growth on service and industry sectors; and
- growth on amount of electric vehicles.

Demand is expected to decrease mainly due to:

- increasing energy efficiency in housing, service and industry sectors; and
- transformation of industry and service sectors towards less energy intensive industries.

**Figure 2-1 – Forecasted demand of electricity in Finland (2015-2025)**




Source: Implementation alternatives of the European Union 2030 climate and energy policy and the realisation of Finland's own climate and energy targets. Pöyry Management Consulting Oy 2016.

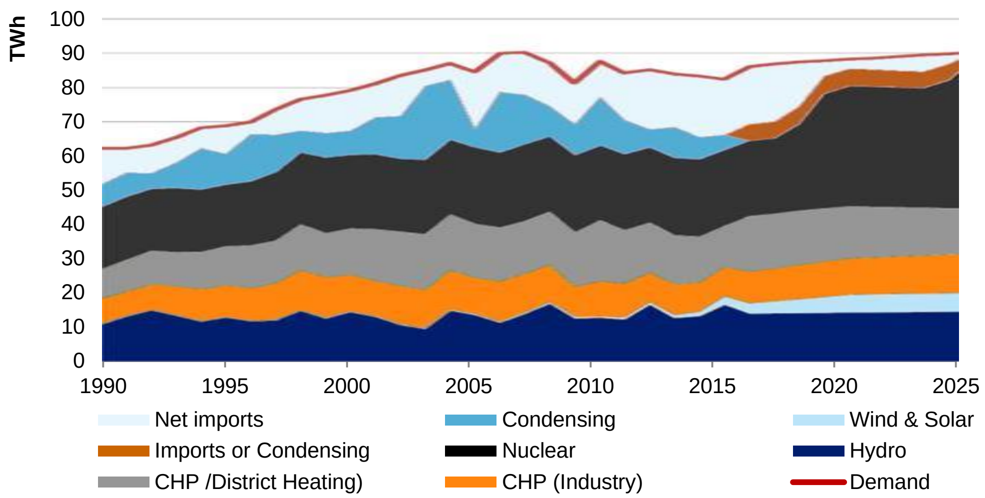
### *2.1.2 Generation and storage*

In electricity generation, the cost of emission free generation capacity remains decreasing and the cost for fossil generation is increasing. Increased amount of electricity is produced by intermittent

[4] Implementation alternatives of the European Union 2030 climate and energy policy and the realisation of Finland's own climate and energy targets. Pöyry Management Consulting Oy 2016. Available at: https://tinyurl.com/yampmko8

renewable generation and inflexible base load capacity[5] (Figure 2-2). The base load capacity will increase due to two new nuclear power plants (Olkiluoto 3 and Hanhikivi 1). The intermittent renewable generation is increased by wind power and solar photo voltaic panels (PV). It is estimated that Solar PV capacity could increase from current 27 MW[6] to roughly 700 MW level by 2030[7]. This would mean that the PV capacity in 2030 is more than 5% of total electricity generation capacity.

**Figure 2-2 – Forecasted electricity generation in Finland (2015-2025)**




Source: Background report of National Energy and Climate Strategy for 2030, 2017

Finland remains a net importer in the future as well, but domestic production capacity and imports are expected to be sufficient to cover peak demand even during cold years provided that cold and non-windy periods do not coincide with large outages[8]. Decreasing regulating power capacity and increasing wind power capacity have an impact on the demand and supply balance for different flexibility services. This means that there could be a need for new sources of flexibility, although Nordic hydro remains the main provider of flexibility in the Finnish system. Interconnectors between neighbouring countries and Central Europe bring Nordic prices closer to Central European prices. This can increase price volatility in Nordics, which increases the attractiveness to participate in demand-side response

In electricity storage technologies it is assumed that seasonal storages are still a challenge in Finland in 2025. Grid level energy storages are assumed to achieve break-even point by 2025, and these can provide ancillary services for power balance. The profitability of grid level storages is dependent on the taxation policies for storages, which are expected to change by 2025. In addition electricity storages might become common in households along with PV panels.

### *2.1.3 Distribution networks*

In distribution networks the investments for security of supply and underground cabling is shifting from urban and sub-urban areas to rural areas. Investments for security of supply will be implemented by 2028.

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5 Background report of National Energy and Climate Strategy for 2030. Available at: https://tinyurl.com/y7q3se9c

6 Energy Authority: https://tinyurl.com/y79ywzhv

7 The potential of distributed energy production in Finland. Pöyry Management Consulting Oy, 2017. Available at: https://tinyurl.com/ybcm96kj

8 Fingrid, Svenska kraftnät, Statnett and Energinet. Nordic perspectives on mid-term adequacy forecast 2017. Available at: https://docstore.entsoe.eu/Documents/SOC%20documents/Nordic/Nordic_perspectives_on_MAF_FINAL.pdf

The amount and variety of controllable loads, such as smart heating and electric vehicles, is expected to increase. In addition there will be an increase in the amount of small-scale production. As a result these will have an impact on customers' consumption and production profiles, which affects to the distribution networks as well. Distribution system operators (DSO) are assumed to adopt power based distribution tariffs in order to improve cost reflectiveness of network service pricing. In addition local bottlenecks are possible in distribution networks due to behavioural changes which might create a need for local flexibility services for DSOs.

The current (5th) regulatory period of electricity distribution operations ends in 2023. Some of the key questions in the following regulatory period will be how to avoid over-investment and passing the costs on to customers, how to incentivise smart solutions (such demand-side response) and what is the acceptable level of security of supply.

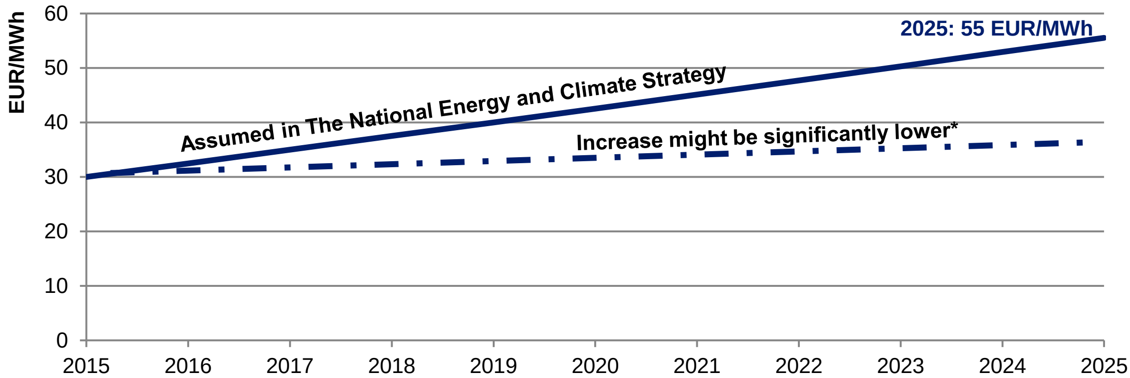
### *2.1.4 Wholesale price development*

The electricity prices are forecasted to increase, but the estimations include a lot of uncertainties. The National Energy and Climate Strategy[9] assumes that price of electricity almost doubles by 2025 compared to current prices. As the forecast includes a lot of uncertainties, the price increase might be significantly lower (see Figure 2-3)

Key factors impacting the development are:

- surplus capacity of electricity generation in Nordics;
- global price development of fossil fuels;
- development of Emission Trading System (ETS) and emission allowance prices; and
- interconnectors between neighbouring countries and Central Europe.

**Figure 2-3 – Forecasted electricity price development in Finland (2015-2025)**




*Low price scenario in Kivihiilen kieltämisen vaikutusten arviointi, a report for Finnish Ministry of Economic Affairs and Employment
Source: Background report of National Energy and Climate Strategy for 2030. Available at: https://tinyurl.com/y7q3se9c

## 2.2 Market design

### *2.2.1 Wholesale and TSO markets*

Wholesale and TSO markets are undergoing a fundamental transition by 2025. The main short-term market design changes and their impact are listed in Table 2-1.

[9] Background report of National Energy and Climate Strategy for 2030. Available at: https://tinyurl.com/y7q3se9c

**Table 2-1 – Key market design changes by 2025**

| Market design change | Schedule* | Impact |
|---|---|---|
| Single price model for production and consumption | 2021 | ▪ All sources of flexibility are treated equally |
| 15-minute imbalance settlement period | 2020** | ▪ Enables trade of 15-min products in the intraday and TSO balancing markets<br>▪ Provides a more accurate price signal for flexibility and imbalances<br>▪ Enables market participants to balance their portfolios more accurately, which could lead to reduced total volumes in the balancing markets<br>▪ |
| New Nordic balancing model based on ACE (Area Control Error) | 2021 | ▪ Costs of imbalance are fully allocated to market participants who cause them |
| Nordic aFRR (automatic frequency restoration reserve) capacity and energy market | 2019 (capacity)<br>2021 (energy) | ▪ aFRR procurement hours and volume will increase significantly |
| Nordic mFRR (manual frequency restoration reserve) capacity market | 2019 | ▪ Additional source of value for providers of flexibility |
| Introduction of pan-European market places | 2018 (intraday)<br>2020-2022 (balancing) | ▪ European Cross-Border Intraday Market (XBID) allows trading intraday market between market participant across Europe<br>▪ European market places for manual and automatic frequency restoration reserves (mFRR and aFRR) products*** provides TSOs access to balancing resources across Europe |
| Updated requirements for frequency containment reserves (FCR) | 2020 | ▪ Updated technical requirements have an impact on supply FCR reserves<br>▪ Procurement amounts in the Nordic synchronous system are expected to change<br>▪ A separate disturbance reserve for down-regulation will be introduced |

*Indicative schedules.
**Derogation possible until 2025, subject to a decision by the Energy Authority.
***The project for mFRR is called MARI (Manually Activated Reserves Initiative) and the project for aFRR is called PICASSO (Platform for the International Coordination of the Automatic frequency restoration process and Stable System Operation).

Sources: Fingrid, ENTSO-E

In the future there will be more distributed resources that can contribute to the system balance in some way. One of the main focus areas for market design is to facilitate the efficient use of these resources. One possible option for this is a market place for distributed flexibility enabled by automated digital solutions. For example, Fingrid’s vision for the real-time market talks about enabling the supply of diverse flexibility resources on a market platform that will aggregate bids of various decentralized and diverse resources according to the needs of the buyer.[10]

### *2.2.2 Retail markets*

In Finland almost all consumption points are metered and settled based on the metered values in the imbalance settlement process. Other Nordic countries are finalizing their AMR roll-outs by the end of this decade. Smart meters have a significant impact on utilisation of DSR and independent aggregator models as near real time consumption data is an enabler for DSR. In addition to smart meters Datahubs have a significant role in the upcoming development of Nordic electricity retail markets. Datahubs enable centralised information exchange in retail markets, which improves market efficiency and simplifies market processes. In addition, introduction of datahubs in all Nordic countries in the beginning of 2020s forms a solid basis for the development of common Nordic retail market.

In addition to datahubs, the introduction of supplier-centric retail market models has risen in to discussion in Nordic countries. In a supplier-centric market model the supplier is the primary contact point for the customer. The supplier-centric market model emphasises the role of electricity suppliers and service providers whereas DSOs act as market facilitators.

Both Norway and Sweden have plans for changing the retail market model to a customer-centric model and Denmark has adopted supplier-centric retail market model in 2016. The current Finnish retail market model is mostly supplier-centric with the exception of billing model, as the customer receives separate bills from supplier and DSO. It is possible that combined billing for both electricity supply and distribution by the supplier is adopted in Finland as well. This would also support the development of common Nordic retail market.

Suppliers and DSOs are likely to introduce new tariff schemes in retail markets. This includes flexibility tariffs where customer gets a reward for offering flexibility. Suppliers might also start introducing quarter-hourly prices in supply tariffs for large customers in addition to the current hourly prices due to implementation of 15 minutes imbalance settlement period on wholesale markets. DSOs are likely to introduce power based distribution tariffs as mentioned before in chapter 2.1.3.

## 2.3 Customers in the future energy markets

Customer empowerment is a driving force in the electricity markets. The transformation towards emission-free energy system and new energy technologies requires activation of end-users.[11] Activation of customers requires that customers feel that they can influence their electricity consumption and costs, and that there is a wide and diverse offering of energy related products and services which meet customer needs.

Digitalisation and data-analytics offer a wide range of possibilities for suppliers and service providers to understand the customer needs and behaviour, and to develop new customer adapted products and services that meet the individual needs. In addition, digitalisation offers ways to bundle products and services in new ways including e.g., demand-response services and smart home solutions. Bundling of products and services increases and diversifies the interactions between service provider network and end-users. Customers' interest in small-scale production is increasing as well. Increase of household small-scale production changes the role of a customer to a prosumer who can have a role of consumer or producer depending on the time.

As a result, electricity retailing is moving from bulk products, where price is the only differentiator, towards more value-based offering. How drastic this change will be depends much on the development of the new product and service offerings by the suppliers and other energy service providers operating in the market.

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[10] Fingrid Current 4.4.2018. Fingrid's Vision for the Real-time Market. Asta Sihvonen-Punkka.

[11] Finnish Smart Grid Vision. Available at: https://tinyurl.com/yc3ajkh2

# 3. DESCRIPTION OF ANALYSED AGGREGATOR MODELS AND MARKETS

This chapter describes the different independent aggregator models and market places analysed in the study.

## 3.1 Markets for selling demand-side response

### *3.1.1 Wholesale markets*

*Day-ahead market*

On the day-ahead (DA) market, physical delivery of electricity is traded on an hourly basis for the following day. These trades are made as auction based on power exchange. Operating requires an agreement with the power exchange and with an open electricity provider, covering balance responsibility[12]. Market participants are typically producers, suppliers, large end-users and other traders or brokers. Buyers and sellers submit bids, minimum of 0.1 MW, for the delivery of power for the following day until 12:00 CET the day before. Majority of annual electricity demand in Finland is bought from the DA market. In 2017, out of the annual electricity demand of 86 TWh[13], 60 TWh[14] was procured from the DA market accounting for a 70% share. System price is set hourly according to buy and sell bids to the point where buy and sell price meet, i.e. to a point where supply and demand is balanced. One area price for Finland is calculated from the system price, taking possible bottlenecks into account.[15]

*Intraday market*

On the intraday (ID) market, trade on physical delivery of electricity starts at 14:00 CET, i.e. two hours after the DA trades close and continues until 30 minutes[12] before delivery. These trades are made on power exchange to further balance the supply and demand. Minimum bid size is 0.1 MW. Prices are set on a pay-as-bid basis i.e. by a first-come, first-served principle. It means that best prices come first, highest buy price and lowest sell price. Basically bids and offers are submitted in EUR/MWh, and are valid until matched, cancelled or amended. Participants in ID market are basically the same as in DA market. Procured volume from ID market in Finland was around 1 TWh in 2017, which equals to a share of 1.2% of total consumption.[15]

Intraday auctions are a new market, complementing the continuous intraday market to create an intraday price signal.[16] The concept consists of two auctions, running at 22:00 and 10:00 CET, to enable trading across bidding zones using cross-border capacities. The 22:00 auction covers all the 24 hourly products for the upcoming day, while the morning auction covers the last 12 hours of the day. The auctions have been introduced in Germany and Nord Pool is also looking at possibly launching the concept in the Nordics.[17]

### *3.1.2 TSO markets*

Fingrid and other Nordic TSOs maintain markets that consist of manual frequency restoration reserves (mFRR), automatic frequency restorations (aFRR) and frequency containment reserves (FCR). In order to participate, market specific technical requirements (see Table 3-1) need to be fulfilled. Reserve provider needs to be the owner of resource or part of its supply chain, i.e. a supplier or a balance responsible party, with the exception of FCR markets. In the FCR markets, if the reserve provider is not the BRP of the resource, the BRP needs to be informed. When these

12 Fingrid. Demand-side management, market places. Available at: https://tinyurl.com/y9p295v2

13 Finnish Energy. Electricity statistics Available at: https://energia.fi/ajankohtaista_ja_materiaalipankki/tilastot/sahkotilastot

14 Nord Pool. Historical market data. Available at: https://www.nordpoolgroup.com/historical-market-data/

15 Nord Pool. The power market. Available at: https://www.nordpoolgroup.com/the-power-market/

16 Nord Pool. Intraday auctions. Available at: https://www.nordpoolgroup.com/trading/intraday-trading/intraday-auctions/

17 Nord Pool. Launch of intraday auctions. Available at: https://tinyurl.com/ybybhb3t

requirements are met, reserve provider has to make an agreement with the TSO to participate in the markets.[18]

**Table 3-1 – Technical requirements for reserve resources**

| Market place | Minimum size | Activation type | Activation time |
|---|---|---|---|
| FCR-N | 0.1 MW | Frequency deviation from 50 Hz, piecewise linear regulation between 49.9 – 50.1 Hz | 3 minutes |
| FCR-D | 1 MW | Piecewise linear regulation when frequency decreases below 49.9 Hz, full capacity at 49.5 Hz | 5 seconds to 50%<br>30 seconds to 100%<br>(with stepwise activation) |
| FCR-D (relay-connected resources) | 1 MW | Alternatively full disconnection | 5 seconds when f ≤ 49.7 Hz<br>3 seconds when f ≤ 49.6 Hz<br>1 second when f ≤ 49.5 Hz |
| aFRR | 5 MW | On TSO's request (activation signal) | Must begin within 30 seconds<br>2 minutes to 100 % |
| mFRR | 5 MW*<br>10 MW | According to the bids | 15 minutes to 100 % |

*With electronic activation

Source: Fingrid

### *Manual frequency restoration reserves*

Manual frequency restoration reserves (mFRR) consist of balancing energy market, also referred to as the regulating power market, balancing capacity market and reserve power plants.

In the balancing energy market, bids are submitted for either upward or downward regulation and given to Fingrid at least 45 minutes before the delivery hour (gate closure time). Capacity is traded according to bids and TSO's need for balancing. Price is formed for each hour for both up- and down-regulation. Up-regulation price is determined by the most expensive upper balancing energy bid used, and set to it or at least as the DA price of the hour. Price for down-regulation is set to the cheapest upper balancing energy bid used, however no more than the DA price of the hour. Bottlenecks between areas are taken into account like in DA market.[19]

There is also the balancing capacity market held by TSO to secure sufficient amount of mFRR to cover a dimensioning fault. Reserve providers place capacity bids on weekly auctions and the bids accepted need to be offered day before at 12:00 CET in the balancing energy market in exchange for a capacity payment. These bids are only activated after the bids on the balancing energy market and when used, are compensated with the same up-regulation price than in the balancing energy market. The provider receives at least the payment for capacity, but can also receive more if received up-regulation prices are more than the total capacity payment for a week. In Finland, total up- and down-regulation in the balancing energy market reached a volume of around 350 GWh[20] in 2017.

[18] Fingrid. Kuinka osallistua reservimarkkinoille (in Finnish). Available at: https://tinyurl.com/y7dhlcol

[19] Fingrid. Balancing Energy and Balancing Capacity Markets. Available at: https://tinyurl.com/ybg24woq

[20] Fingrid. Reservihankinnan ajankohtaiskatsaus 2018 (in Finnish). Available at: https://tinyurl.com/yamxpudf

### *Automatic frequency restoration reserves*

Automatic frequency restoration reserve (aFRR) is a reserve, which is automatically activated on TSO's request based on frequency deviation. To participate, the reserve provider has to carry out regulation tests to verify that capacity offered for reserves meet the requirements, and the capacity needs to be located in Finland or directly connected to the Finnish grid.

Procurement of up- and down-regulation is done only to weekday morning and evening hours, when frequency variations are most challenging. This procurement schedule is set in advance by the Nordic TSOs. The participant can then leave bids with capacity and price for the following day's hours at 16:00 CET the day before. The required bids for both up- and down-regulation are used in merit order and the bids are confirmed by 17:05 CET. The activation is compensated with capacity payment set in the bid and energy fee with the up- or down-regulation price, depending on which regulation takes place on the hour.[21] In 2017, 10 GWh of down-regulation and 13 GWh of up-regulation were procured from the aFRR market[22], but this is expected to increase. For 2018, the capacity procured on the Nordics from aFRR was doubled to 300 MW (compared to 2017), of which Fingrid's share is 70 MW.[23]

The Nordic TSOs plan to increase aFRR procurement hours and volume in the near future to prepare for the new Nordic balancing concept and implementation of area control error (ACE, see Table 2-1). The number of hours will be evaluated for each quarter of the year until introduction of the Nordic aFRR capacity market, expected in Q2/2019, and increased after that in even steps until Q2/2020. After this, volume level of 300 MW in the Nordics is expected to be increased to 600 MW by Q1/2021.[24]

### *Frequency containment reserves*

There are frequency containment reserves for normal operation (FCR-N) and for disturbances (FCR-D). The capacity needs to be able of continuous full activation of at least 30 minutes and be activated in steps according to frequency deviation. Also, FCR-N market requires symmetrical bids i.e. matching up- and down-regulating bids. Meeting of these requirements need to be verified by regulation tests. In FCR-N and FCR-D, the reserve provider does not necessarily have to be the reserve owner or part of its' transparent supply chain. In this case, reserve provider needs to have the reserve owners' permission for operating the reserve and inform the balance responsible party about it.[25]

In FCR-N and FCR-D markets it is possible to participate in annual or hourly markets. To enter the annual markets, it is needed to take part in the tendering process done once a year during fall. Bids with certain capacity and price set are tendered, and the largest accepted price in EUR/MW,h fixes the capacity payment for all participants for the next year. The capacity payment in FCR-D annual market was 4.7 EUR/MW,h in 2017 and 2.8 EUR/MWh in 2018. Respectively for FCR-N, the prices were 13 EUR/MW,h in 2017 and 14 EUR/MW,h in 2018[26]. In the annual market, a reserve plan is left with bids regarding capacity for the following day at 17:00 CET day before.

The hourly markets are used for additional procurement for the following day if necessary, day before at 17:30 CET. The pricing principle is the same: bids are used only when needed and in price order, where the cheapest bid is used first and the most expensive used bid sets the capacity payment for all. For each hour the capacity is offered, Fingrid reimburses the capacity payment set. In the FCR-N market, participants are also compensated for the activated energy with a certain

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[21] Fingrid. aFRR agreement (in Finnish). Available at: https://tinyurl.com/y8nyks3w
[22] Fingrid. Open data. aFRR. Available at: https://data.fingrid.fi/en/dataset?q=aFRR
[23] Fingrid. aFRR in 2018. Available at: https://tinyurl.com/y97y6qs6
[24] Fingrid. Announcement 21.3.2018. Plan to increase aFRR. Available at: https://tinyurl.com/yb48mx7v
[25] Fingrid. Application instruction for frequency containment reserves. Available at: https://tinyurl.com/y7rdx4ze
[26] Fingrid. FCR-N and FCR-D transactions in the hourly and yearly markets. Available at: https://tinyurl.com/ybmsvt6k

price.[27] In Finland, the activated total volume for FCR-N was around 300 GWh in 2017, of which half was domestic supply[20].

## 3.2 Description of different aggregator models

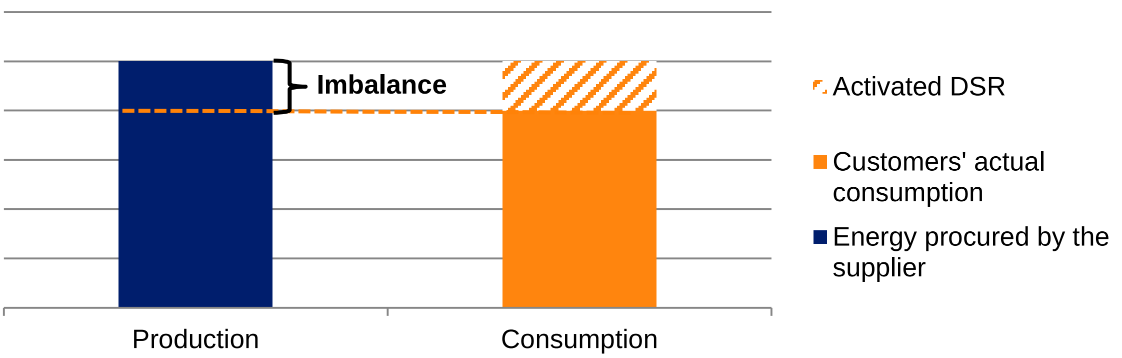
The study analyses four different independent aggregator models which are described in the following sub-chapters. The main difference between models is how the supplier or Balance Responsible Party is treated in terms of imbalance correction and compensation. As described in chapter 1.1 the key questions in this study relate to risk management between market participants and obligations and responsibilities of an independent aggregator.

Balance responsibility refers to the fact that each market participant must take continuous care of its balance, i.e. there should be a balance between production/procurement and consumption/sales within imbalance settlement period. In practice, market participants cannot do this by themselves and there must be an open supplier who balances the power balance. A party whose open supplier is Fingrid is referred to as a Balance Responsible Party.

The open delivery between Fingrid and a BRP is agreed upon through a balance service agreement, whose terms are public and equal to all. In addition, the BRP signs an imbalance settlement agreement with eSett Oy.

As the aggregator is operating the flexible loads of the customers, it causes imbalances in the BRP's balance portfolio (Figure 3-1). The following models for independent aggregation address these direct effects in different combinations of correction and compensation.

**Figure 3-1 – Imbalance caused by DSR activation**




The production and consumption would have been balanced in case there were no DSR activated. Activation of DSR reduces the consumption causing imbalance between production and consumption, which causes costs to the balance responsible party.

### *Model A: Imbalance volume correction with no compensation*

In model A there is a neutral party who corrects the BRP's imbalance volumes based on the demand-response that was activated. In case of TSO markets the natural party for the correction would be TSO but in day-ahead and intraday markets there might be also other actors who could obtain this responsibility. This is implemented by additional step in the beginning of the imbalance settlement process. There is no compensation paid to the BRP by any market participant.

### *Model B: No imbalance volume correction or compensation*

In model B there is no correction of imbalance volumes, which means that there are no additional steps relating to the imbalance settlement process compared to the current process. The BRP is compensated through the imbalance settlement, which means that BRP compensation is socialised in the imbalance settlement.

[27] Fingrid. Rules and fees for the hourly market of frequency controlled reserves. Available at: https://tinyurl.com/y7rdx4ze

### *Model C: Imbalance volume correction and compensation*

In model C TSO corrects the BRP's imbalance volumes based on the demand-response that was activated in a similar way as in model A. In addition, BRP is compensated by the aggregator at a predefined reference price. There are several possible models to determine reference price for the compensation: DA price, DA price + margin (e.g. defined by the regulator) or retail price, which consists of DA price and supplier's margin.

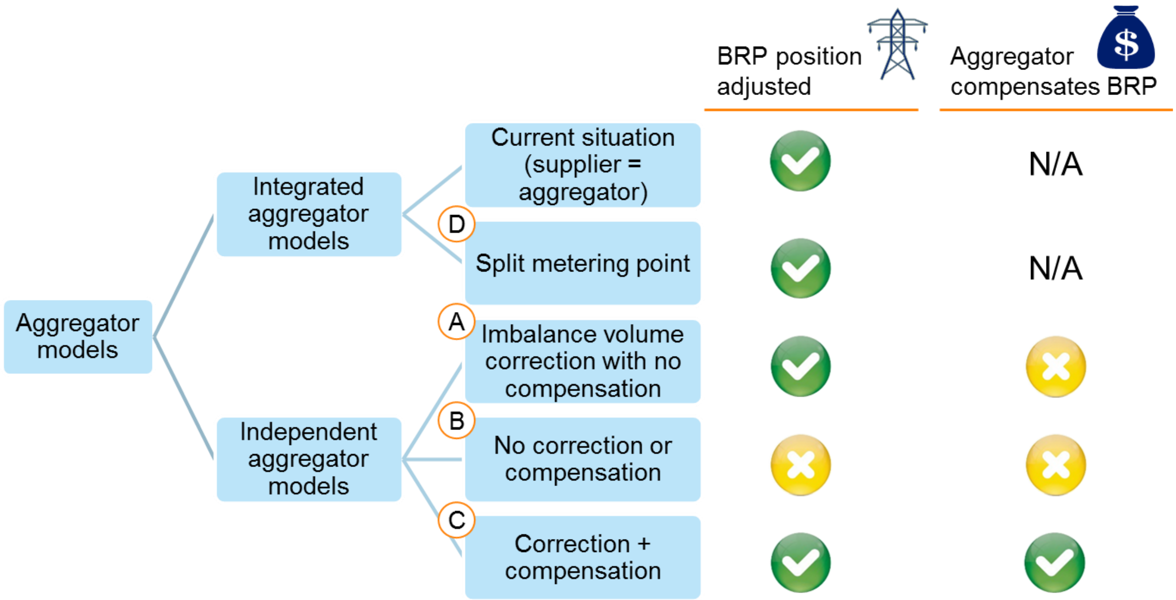
### *Model D: Split metering point*

In model D the aggregator could supply the flexible part of the demand, e.g., electric vehicle or electric heating and the traditional supplier would supply the rest of the electricity. Customer would have two balance responsible suppliers. This model requires separate metering for flexible and non-flexible consumption, which leads to high entry cost due to the need of establishing a sub-metering point. This model does not impose unintended costs on other players as the aggregator would have to arrange its balance responsibility. On the other hand, the requirement of being balance responsible means that model D is not an actual independent aggregator model but integrated aggregator model.

### *Classification of the analysed models*

The analysed independent aggregator models can be classified based on whether the BRP position is adjusted and whether the aggregator compensates the BRP (Figure 3-2). The models differ based on balance responsibility, imbalance correction for BRPs and aggregator compensation.

**Figure 3-2 – Classification of analysed models**




### *Current aggregator models used in Finland*

Two of the models described are currently in use or piloted in Finland[28]. A model with no correction or compensation (model B) has been implemented in the beginning of 2017 in the FCR-D market.

[28] Energinet, Fingrid, Statnett, Svenska kraftnät. Unlocking flexibility. Nordic TSO discussion paper on third-party aggregators. Available at: https://tinyurl.com/y8odywhk

A model with correction and compensation (model C) has been implemented in the FCR-N market[29] from the beginning of 2018, and is currently piloted in the mFRR market.

The reasoning behind choosing model B for FCR-D and FCR-N is that the activations are rare and short-term, which leads to low amounts of activated energy and little impact on BRP imbalances. In addition, FCR-D is currently only procured as upward regulation, so the activation causes a surplus to the BRP's balance. The TSO is buying the surplus energy from the BRP with the up-regulating price and this often leads to profiting BRP more as it is typically an up-regulating hour when disturbances happen.

Model C is currently piloted in the mFRR market[28]. In the pilot, the TSO verifies the activated energy based on real time measurements which the aggregator is delivering to the TSO according to general requirements in the Nordic mFRR market. TSO calculates the actual delivery and the imbalance caused by reserve activation per BRP based on the measurements and a case specific baseline model. The TSO then removes that imbalance from the BRP with a trade that is priced with the day-ahead market price for the activation hour. The aggregator receives the difference between the mFRR price and the day-ahead market price as compensation for the balancing service.

In both cases the aggregator can aggregate resources regardless of who is the customer's BRP, but the aggregator has to inform the BRPs about their customer participating in demand-side response. It has been considered important that the BRP is aware of the changes in the customer's behaviour and is not making counter measures to balance their portfolio. The starting point has been that the BRP should know the participating volume and maybe even customers if they constitute a significant share of their portfolio.

[29] Fingrid. Kuinka osallistua reservimarkkinoille (in Finnish). Available at: https://tinyurl.com/y7dhlcol

# 4. APPROACH AND ASSUMPTIONS

The financial impact assessment in sections 5.1 and 5.2 focuses on the distributional effects and especially their relative difference in the different models. This section describes the approach for the financial assessment:

- Section 4.1 explains how the cash flows are distributed between different market participants in each model during different consumption hour types.
- Section 4.1 describes the methodology used in the desktop analysis with the help of a worked example.
- Section 4.3 then describes how the worked example has been extended for a whole year in order to assess the overall financial impact for different stakeholders.

## 4.1 Description of cash flows in different models

This chapter describes the cash flows between market participants in each model during different consumption hour types. Supplier and BRP are considered as a combined market participant (supplier / BRP) in the analysis as the supplier can be a BRP or it can outsource the balance responsibility to a service provider. The outsourcing agreement between supplier and BRP means that the supplier and BRP would have an agreement on the sharing of the imbalance risk.

In the analysis it is assumed that the supplier would procure electricity only from the day-ahead market. This assumption is done because day-ahead price data is public information and determines electricity price for every hour of the year. In real case, the supplier can procure electricity also from other markets or with bilateral contracts.

### *4.1.1 Normal consumption hour*

In case of normal consumption hour the customers consume their electricity as planned and the supplier makes a profit which is the difference between revenue received from the customer and the procurement cost of the electricity. Figure 4-1 describes the cash flows in case the supplier has procured the electricity from DA market and sold it forward to the end user. This cash flow is not dependent on the aggregator model.

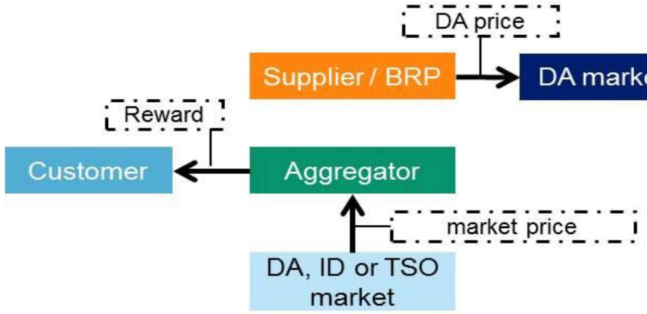
**Figure 4-1 – Cash flows during normal consumption hour**


### *4.1.2 Consumption hour with activated demand-side response (DSR hour)*

The cash flows during DSR hour differ between models but they are similar regardless of which market aggregator is offering the DSR. In this chapter cash flows are described in case the aggregator participates to a market where the amount of energy is significant.

Figure 4-2 illustrates the cash flows in model A (imbalance volume correction). In this model the supplier has procured electricity from the DA market but is unable to sell it to the customer who is participating in demand-side response and thus decreased the consumption during the hour. The supplier's / BRP's imbalance volume is corrected before the actual imbalance settlement, which means that the supplier would make a loss from the surplus electricity. The aggregator will make a profit by selling the DSR, and give a reward to the customer for offering the DSR based on their mutual contract.

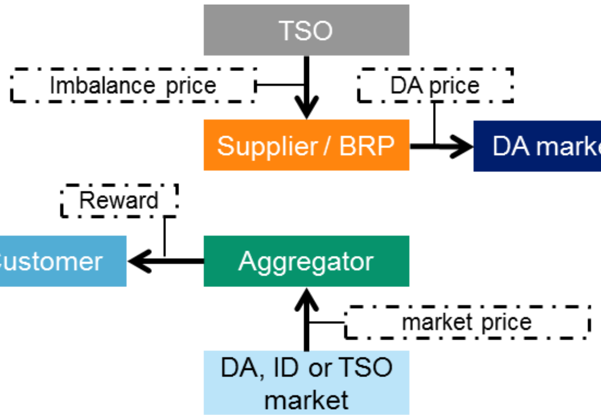
**Figure 4-2 – Cash flows in model A, imbalance volume correction with no compensation**




Note: TSO market refers to both balancing market and reserves

Figure 4-3 describes the cash flows in model B (no imbalance volume correction or compensation). In this model the supplier has procured electricity from the DA market and is unable to sell it to the customer. As there is no imbalance volume correction, the supplier / BRP is long during the DSR hour and receives the imbalance price from the TSO. TSO would socialise this cost to other suppliers / BRPs, e.g., by increasing the balancing service fees. It is noteworthy that the model result in double payment for the flexibility, as the aggregator receives payment from the market and supplier receives payment from the TSO through imbalance settlement.

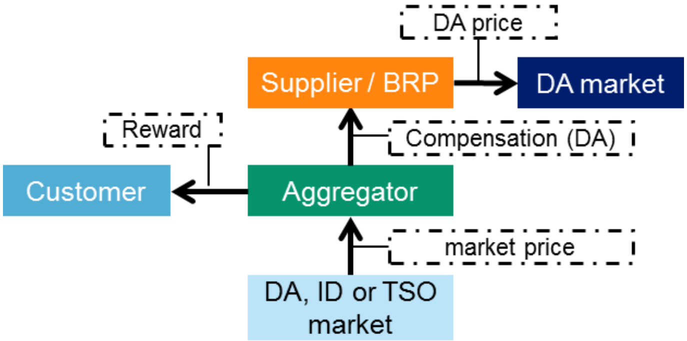
**Figure 4-3 – Cash flows in model B, no imbalance volume correction, no compensation**




Note: TSO market refers to both balancing market and reserves

Figure 4-4 illustrates the cash flows in model C (imbalance volume correction with compensation). The supplier has procured electricity from DA market and the imbalance volume is corrected before the actual imbalance settlement as in model A. In difference to model A, the supplier / BRP is compensated by the aggregator. The aggregator will make a profit by selling the flexibility, and give a reward for the customer for offering the flexibility based on their mutual contract. In addition, the aggregator pays the compensation for the supplier / BRP. There are different options to set the amount of compensation, e.g., DA price (as in the figure) or DA price + margin set by the regulator.

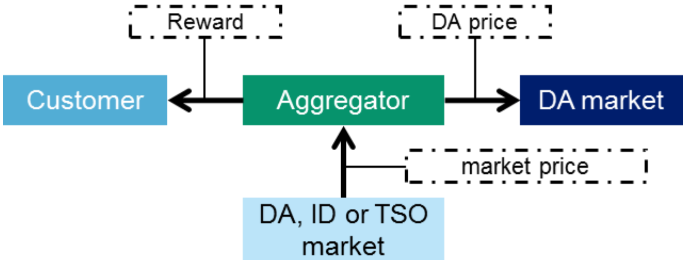
**Figure 4-4 – Cash flows in model C, imbalance volume correction and compensation**




Note: TSO market refers to both balancing market and reserves

In model D, (split metering point) the aggregator supplies electricity to the customer's flexible demand, such as heating and electric vehicle charging, and the traditional supplier would supply the rest. This means that there are no distributional effects and the cash flows would arrange same way as in the case of integrated aggregator (Figure 4-5). The aggregator would have the risk of incurred imbalances as it is also a BRP in this model.

**Figure 4-5 – Cash flows in model D, split metering point**



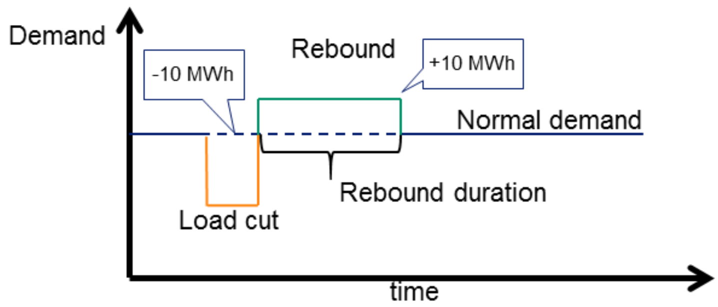

Note: The Aggregator would have to arrange its balance responsibility as it acts as a supplier. TSO market refers to both balancing market and reserves

### *4.1.3 Load shifting and rebound effect (rebound hour)*

Demand-side response can take many forms depending on the type of end user. End users have different physical possibilities to offer flexibility. The ability to offer flexibility depends on both the physical installations at the end user level, and on the end user's behavioural preferences. For example, an end user with electric heating has better ability to provide flexibility than an end user with district heating.

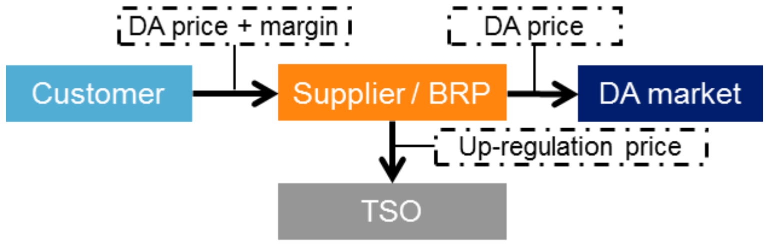
From the aggregator business perspective, the main forms of demand-side response are load shifting and peak clipping. Load shifting means short term shift of load over the day to reduce peak load, while consuming the same amount of energy over day. This is referred as rebound effect (Figure 4-6). Peak clipping means reduction of the peak load without consuming the same amount of energy in any other hours (no rebound effect). Typically this form of demand-side response is referred as energy efficiency as the total amount of energy used decreases. It is also possible that the aggregator activates customers' loads during hours when electricity is cheap (i.e. down regulation), which also alters the normal consumption profile. Down regulation is not in the focus of this analysis as it would not cause similar issues in imbalance settlement as up-regulation where the consumption is decreased..

**Figure 4-6 – Illustration of the rebound effect**




The rebound effect has a cost impact on the supplier / BRP which is referred as rebound cost. The supplier has procured an insufficient amount of electricity for the rebound hours. This means that the supplier / BRP has to procure the additional electricity as imbalance power and pay the imbalance price to the TSO. The cash flows during rebound hours are illustrated in Figure 4-7. It is noteworthy that in real life rebound effect is dependent on the type of the load as some loads can be deactivated for a longer period of time or partly deactivated.

**Figure 4-7 – Cash flows during rebound hours**




Note: The supplier procures electricity from DA market based on the forecasted demand of the customer. As the customer's demand is higher during the rebound hour than originally forecasted, the supplier needs to procure additional electricity from the TSO as balancing power due to rebound effect. In case the supplier is aware of the rebound effect and forecasts the increase in demand for the rebound hour correctly, the supplier can procure all electricity from DA (or ID) market and avoid buying electricity on up-regulation price.

## 4.2 Worked example on financial impact assessment methodology

The methodology used for financial impact assessment is illustrated with the help of a worked example. In this example it is assumed that the aggregator would bid in the balancing energy market i.e. regulating power market. The situation is as follows:

- In normal situation customer has steady consumption of 10 MWh/h. This can be offered to the balancing market as flexible capacity of 10 MW for one hour via aggregator.
- If DSR is activated (demand reduced by 10 MWh) the consumption will shift fully to the following hour as a rebound effect (demand increases to 20 MWh for the next hour)
- There are two consecutive up-regulation hours and the customers shift their flexible loads from the hour 1 (DSR hour) to hour 2 (rebound hour).
- Hourly price data is as shown in Table 4-1
- Supplier has a sales margin of 2.5 EUR/MWh, i.e., retail price is 42.5 EUR/MWh
- Trading and balance management costs are excluded from the calculations as they are not dependent on the models

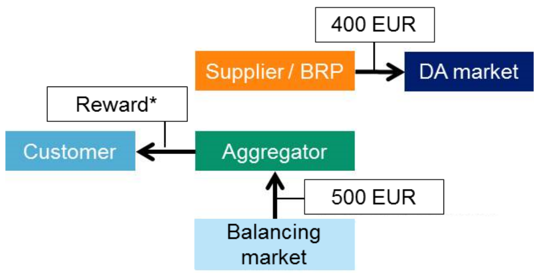
**Table 4-1 – Hourly price data in worked example**

| | DA price | Up-regulation price | Imbalance price |
|---|---|---|---|
| **Hour 1** | 40 | 50 | 50 |
| **Hour 2** | 40 | 50 | 50 |

Figure 4-8 describes the cash flows and net positions of different stakeholders during DSR hour in each model.

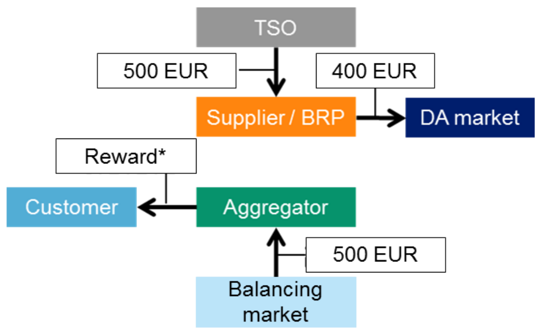
## Figure 4-8 – Cash flows and net positions for DSR hour in worked example

### Model A: Imbalance correction with no compensation



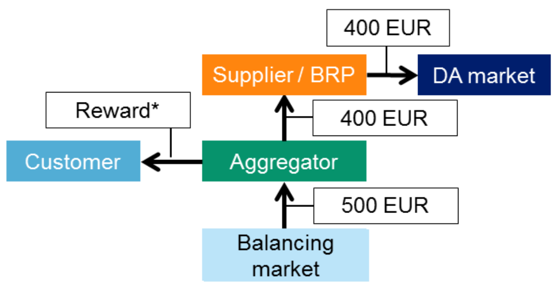

| Net positions | |
|---|---|
| Supplier / BRP | -400 EUR |
| Customer | +Reward |
| Aggregator | +500 EUR |
| DA market | +400 EUR |
| Balancing market | -500 EUR |
| SUM | 0 |

### Model B: No imbalance correction or compensation



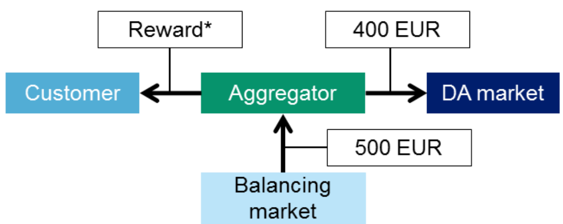

| Net positions | |
|---|---|
| Supplier / BRP | +100 EUR |
| Customer | +Reward |
| Aggregator | +500 EUR |
| TSO | -500 EUR |
| DA market | +400 EUR |
| Balancing market | -500 EUR |
| SUM | 0 |

### Model C: Imbalance correction with compensation




| Net positions | |
|---|---|
| Supplier / BRP | 0 EUR |
| Customer | +Reward |
| Aggregator | +100 EUR |
| DA market | +400 EUR |
| Balancing market | -500 EUR |
| SUM | 0 |

### Model D: Split metering point



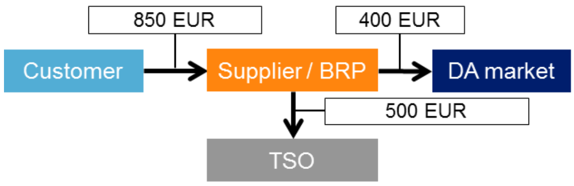

| Net positions | |
|---|---|
| Supplier / BRP | 0 EUR |
| Customer | +Reward |
| Aggregator | +100 EUR |
| DA market | +400 EUR |
| Balancing market | -500 EUR |
| SUM | 0 |

Note: In model D the aggregator is a balance responsible. Net position of the supplier / BRP refers to the fact that there are no distributional effects on other suppliers / BRPs.

*Customer's reward from the aggregator is based on a mutual agreement and reduced from the aggregators net position.

Figure 4-9 illustrates the cash flows and net positions for the rebound hour. The rebound cost causes additional cost for the supplier / BRP as it has to procure imbalance power. This cost is not dependent on the model used, except in model D where the aggregator itself is a BRP and pays the rebound cost. In this example the rebound cost would be 500 EUR as the supplier is 10 MWh short during rebound hour due to rebound effect. In addition, the customer pays for 20 MWh of electricity for the supplier as 10 MWh of demand has shifted from DSR hour to the rebound hour.

**Figure 4-9 – Cash flows and net positions for rebound hour in worked example**




| Net positions | |
|---|---|
| Supplier / BRP | -50 EUR |
| Customer | -850 EUR |
| TSO | +500 EUR |
| DA market | +400 EUR |
| SUM | 0 |

Note: During rebound hour customer consumes 20 MWh. Supplier procures 10 MWh from DA market and 10 MWh as imbalance power for being short during the hour. In model D the aggregator is also a supplier / BRP and therefore would pay the rebound cost and there would be no distributional effects on other suppliers / BRPs.

As a result, each market participant's net positions after the two hours will align as shown in Table 4-2. Note that model D where the aggregator has balance responsibility describes the situation for an integrated aggregator as well. It is noteworthy that TSO is not actually directly profiting in any of these systems as it is a party who carries the costs and distributes them to other market actors.

**Table 4-2 – Net positions after two consecutive up-regulation hours (EUR)**

| | Supplier | Aggregator | TSO | Customer* |
|---|---|---|---|---|
| **Model A** | -450 | +500 | +500 | -850+reward |
| **Model B** | +50 | +500 | 0 | -850+reward |
| **Model C** | -50 | +100 | +500 | -850+reward |
| **Model D** | 0 | +50 | +500 | -850+reward |

*Customer would have paid 850 EUR for the 20 MWh of electricity even though there would not have been DSR. Customer's position is improved compared to the normal consumption hours by the reward received from the aggregator during DSR hour.

## 4.3 Assumptions for the analysis

To assess the overall financial impacts on different stakeholders the worked example described in chapter 4.2 has been extended for a whole year and applied to actual market data including hourly demand, day-ahead, up-regulation and imbalance prices in 2017. The quantitative analysis is conducted for models A, B and C. Model D is not part of the quantitative analysis as there are no distributional effects and therefore model D is analysed only qualitatively. The assumptions behind the impact assessment are described below.

### *Amount of activated DSR on a DSR hour*

The volume of flexible demand offered to the market by the independent aggregator is set to be 0.1% of hourly consumption volume. With this assumption, the hourly maximum reaches a value of 14 MWh/h and minimum of 6 MWh/h, with an average of 10 MWh/h offered to the market. This assumption is set as an example as the aim of the impact analysis is to compare differences between the models. The amount of flexible demand does not have impact on the comparison results as long as the same assumption is used in all models.

*Aggregator's operating principle and cash flows*

The aggregator offers demand-side response to the balancing energy market i.e. the regulating power market, referred simply as the balancing market in the analysis.[30] The profitability of offering DSR on balancing market is evaluated for each hour of the year according to the actual market prices. To simplify the impact assessments, it is assumed that there is only one aggregator operating on the market. Further, it is assumed that the aggregator has a large enough pool of flexible resources in its portfolio, which enables the aggregator to activate DSR on a steady basis even in consecutive hours, i.e., DSR is offered for every hour and activated if profitable.

The aggregator is assumed to insert a bid at every hour. The aggregator's bidding logic has an impact on the amount of DSR hours during a year. If the aggregator has no expectation for any specific spread between up-regulation and DA prices, DSR is activated on 33% of the hours in a year. In other words, the aggregator acts if the up-regulation price is higher than the DA price. If the aggregator is assumed to bid only with a fixed spread of 3 EUR/MWh between the up-regulation and DA price, the share of DSR hours in a year decreases to 20%.

Aggregator's revenue is simply calculated by multiplying the volume of flexible demand with up-regulation price. In model C, the compensation for supplier/BRP is calculated by multiplying the volume of flexible demand with DA price. The final net position of the aggregator is addressed simply by subtracting possible compensation for supplier / BRP from DSR revenues.

*Rebound effect and rebound cost*

The quantitative analysis includes an estimation of the impact of load shifting and the resulted rebound costs (see 4.1.3). It is assumed that the rebound volume is 100% of the consumption reduced during DSR hour, which means that annual demand stays the same.[31] The load is assumed to be cut for one hour, after which the rebound effect starts to take place in the following hour. Rebound volume is assumed to shift evenly for 1, 2 or 4 hours after the DSR hour. The length of the rebound effect affects the rebound costs, as the price for rebound volume is set according to the imbalance price of the hour. The final rebound cost is dependent on the amount of DSR hours, duration of the rebound and the imbalance price during the rebound hours.

*Customers' compensation and costs*

Customers' compensation for offering flexibility is not taken into account as it is an agreement between the customer and the aggregator, which can take multiple forms. The agreement can be based on e.g. fixed compensation annually or on flexible hours, or on a share of the profit from flexibility

As mentioned, it is assumed that the end-users consume the same amount of electricity due to load shifting. It is also assumed that the customer procures the electricity with a contract based on list prices. This means that the annual electricity procurement costs for the customers stay the same.

*Supplier's and Balance responsible party's position*

The supplier is assumed to buy the same amount of electricity from the DA market as in the case of all hours being normal consumption hours. The rebound effect incurs costs for the supplier as the supplier has procured an insufficient amount of electricity for the rebound hours. This means that the supplier has to procure the additional electricity as imbalance power and pay the imbalance price to the TSO. This simulates the situation where the supplier is unaware of their customers participating in demand-side response.

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[30] Impacts from offering DSR on other markets are similar and described qualitatively in chapter 5.2.

[31] It is possible that aggregation leads to peak clipping instead of load shifting. In that case, the impact of rebound effect would be smaller than in case of 100% load shifting.

# 5. EVALUATION OF DIFFERENT AGGREGATOR MODELS

## 5.1 Financial impact assessment on different stakeholders

In this chapter, the distributional effects on different stakeholders have been analysed through quantitative analysis, where the redistribution of cash flows in the different models have been quantified in the case of the activated DSR by an independent aggregator.

### *5.1.1 Suppliers and balance responsible parties*

Impact of different models on suppliers and BRPs is addressed by estimating the relative change in electricity procurement costs for the flexible demand participating in DSR.

The balance responsible party buys electricity as if a normal consumption hour were to take place. When aggregator activates DSR, the customers' consumption decreases and BRP is not able to sell all the procured electricity to the customers. Therefore a surplus is created. The impact of this surplus electricity varies between models. In model A the supplier is not able to sell the surplus electricity and makes a loss. In model B TSO compensates the surplus through imbalance settlement. In model C aggregator pays the compensation.

Furthermore, the BRP whose customers are participating in DSR via aggregation, has to bear the rebound costs (see 4.1.3). With the assumptions made, annual rebound costs for different rebound durations vary between 0.7-1.2 MEUR (Table 5-1).

It is notable that the rebound volume is 100% of the DSR volume, i.e. the annual consumption is assumed to stay at the same level. This means that all DSR is assumed to be load shifting to future hours. Peak clipping is one form of DSR, where the electricity consumption is cut on the peak hour and not used at all. This would lead to reduced rebound costs for the BRP as well as to savings in total energy costs and reduction of emissions.

**Table 5-1 – Annual rebound costs for different shift durations, MEUR/a**

| | 1 hour | 2 hours | 4 hours |
|---|---|---|---|
| Models A-C | 0.8–1.2 | 0.7–1.1 | 0.7–1.0 |

Note. The rebound cost is dependent on the amount of flexible hours in the year. I.e. higher amount of flexible hours leads to higher rebound costs. In figures above the share of flexible hours ranges from 20% to 33%.

The rebound costs are not dependent on the model, and only change according to shift duration and amount of DSR hours during the year. According to the 2017 imbalance price data, longer rebound duration leads to lower rebound costs. This is mainly because the following hour after an up-regulation hour is probable to be an up-regulation hour as well. Longer rebound duration increases the probability that not all of the rebound hours are up-regulation hours.

There are also differences between the models due to possible compensations the BRP receives. Compensations and procurement costs for the flexible part of the demand in different models are shown in Table 5-2[32] and Figure 5-1. The procurement costs and compensations are sensitive to the amount of flexible hours in year.

It should be noted that the figures represent the upper bound of impact for suppliers because it assumes:

- full exposure to imbalance prices, i.e. no ability to procure intra-day to cover rebound effect; and
- no expectation or foresight of possible demand variation, and hence no forward options to cover this.

[32] Table 5-1 findings are incorporated into Table 5-2 under the rebound cost row

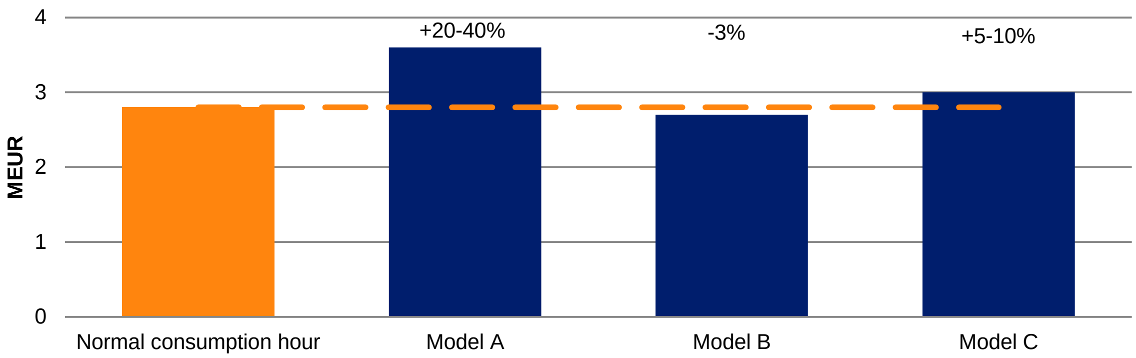
**Table 5-2 – Procurement costs* and compensations for the supplier / BRP, MEUR/a**

| | Model A | Model B | Model C |
|---|---|---|---|
| DA procurement | -2.8 | -2.8 | -2.8 |
| Rebound cost | -(0.7–1.2) | -(0.7–1.2) | -(0.7–1.2) |
| Imbalance revenue | N/A | +0.9–1.2 | N/A |
| Aggregator's compensation to the BRP | N/A | N/A | +0.5–0.9 |

*includes procurement costs for the flexible demand only

Note: In figures above the range of costs and compensations vary depending on the amount of flexible hours from 20% to 33%.

**Figure 5-1 – Comparison of net costs* for supplier / BRP**




*includes procurement costs for the flexible demand only

Note: The range of cost impact is dependent on the amount of flexible hours in the year. A higher amount of flexible hours leads to higher rebound costs, imbalance revenues and aggregator's compensations. In figures above the share of flexible hours ranges from 20% to 33%.

In model A, imbalances for the hour when the flexibility is activated are corrected, but no compensations are paid to the BRP. In this case BRP ends up paying for the rebound costs accumulated due to flexibility provision without any imbalance revenue, which leads to a significant increase in the electricity procurement costs for the flexible part of BRP's portfolio. The total net costs are 20-40% higher on the share of flexible demand in supplier's portfolio than in case of normal consumption hour. As a consequence sales margins in model A from flexible customers would decrease and the supplier could increase retail prices in order to account for the increased volume risk.

In model B, the BRP is compensated, and receives the imbalance price from the TSO for being long during the hour of activated flexibility. BRP's day-ahead procurement and rebound costs stay the same, but the imbalance revenue is a bit higher than the rebound costs. As a result, the electricity procurement costs for flexible demand would slightly decrease. However, this imbalance revenue is paid by the TSO and would probably lead to increases e.g. in TSO's balancing service prices which is further analysed in section 5.1.4.

In model C, the supplier receives DA price for DSR hours from the aggregator as compensation. This leads to a situation, where the BRP's net position is zero on flexible hours, as there aren't any other costs included. Aggregator's compensation to the BRP is between 0.5-0.9 MEUR, depending on the amount of flexible hours in the year. However, during the following hour, BRP is in a short position due to load shifting and ends up paying the rebound cost. The rebound costs are higher than aggregator's compensation, which results in slightly higher net cost regarding flexible part of the demand for BRP (varies between 5-10%). In this model, only the BRPs whose loads are aggregated would be affected by the aggregator, i.e. no socialization of costs takes place in this model.

To conclude the impacts on the BRP and supplier point of view, model B is the most attractive as they also gain the benefit from the activated DSR.

*Evaluating cost on a portfolio level*

The procurement costs presented so far have regarded only the share of flexible part of the BRP's demand portfolio. This impact is equivalent to a situation, where the BRP's whole portfolio is taking part in DSR. The impact to BRP's overall procurement costs depends on the share of flexible demand in the BRP's portfolio. Hence, the final impact is calculated as impact on flexible part of the demand (%) multiplied by share of flexible demand in the portfolio (%).

The significance of increased procurement costs for flexible demand can be assessed by following worked example:

Assuming for example that the flexible share of demand is 5% of the BRP's portfolio and that supplier's procurement costs for the flexible share of demand change by 30% in model A, -3% in model B and +7% in model C[33]. These would lead to following final impacts in different models:

- Model A: 5% x 30% = +1.5%
- Model B: 5% x (-3%) = -0.15%
- Model C: 5% x 7% = +0.35%

As is evident from the results, the significance of increased procurement costs for total demand remains relatively low in models B and C, while the increase in model A can be significant, if the share of flexible demand is high in the BRP's portfolio. This is due to the fact that suppliers' sales margins are typically only a few percentages, which means that in model A it is possible that the supplier would lose margins of several consumption hours due to DSR activated by the aggregator.

### 5.1.2 Aggregators

Aggregator's revenues are the same in each model with the assumptions made (see section 4.3). This is because comparing hourly up-regulation prices to DA prices is valid for all the models. The aggregator's final net position depends on the possible compensations paid for BRP (Table 5-3).

Models A and B lead to the highest net position as the aggregator is not required to compensate the supplier / BRP. In model C the aggregator compensates the supplier / BRP by the costs of surplus energy procured from the DA market. This leads to a result that from the aggregator's perspective models A and B are clearly the most attractive ones. Model C reflects better the value of flexibility as the aggregator compensates costs caused to the supplier/BRP, hence the aggregator's net position is determined by the spread between the DA and up-regulation price.

[33] Changes in procurement costs are chosen as an average from Figure 5-1

**Table 5-3 – Aggregator's net position in each model (MEUR)**

| | Model A | Model B | Model C |
|---|---|---|---|
| Revenues | 0.9–1.2 | 0.9–1.2 | 0.9–1.2 |
| Compensation for suppliers / BRPs | 0 | 0 | 0.6–0.9 |
| **Net position** | **0.9–1.2** | **0.9–1.2** | **0.3** |

*Compensation for customers is not taken into account. The actual net position is lower depending on the reward for the customer.

Note: In figures above the range of costs and revenues vary depending on the amount of flexible hours from 20% to 33%.

### *5.1.3 Customers*

The final financial impact indication for customer participating in DSR is calculated through assessing the total income from flexibility in EUR/MWh, which would be shared between the customer and the aggregator. In addition the increase in electricity bills due to BRP transferring the increased procurement costs to the consumers is taken into account.

The income from flexibility is assessed through aggregator's net position and the demand that has been activated during the year (section 5.1.2). This is the total income from flexibility per MWh for the aggregator, and it's assumed to be shared between the aggregator and customer.

The activated DSR leads to changes in BRP's procurement costs for flexible demand (Table 5-2 in section 5.1.1). These are the costs caused to the BRP due to DSR and rebound effect, and it is assumed that these costs would be fully transferred to the customer as increases in electricity bills. It should be noted that in models A and C, the increase in electricity costs is transferred only to the flexible demand. In model B the costs are socialised to all BRPs, which results to significantly lower increases in electricity bills since also the customers who are not participating in DSR are paying the costs (see section 5.1.4).

From these valuations we have an indication of the net result for the customer and the aggregator, i.e. the amount of money left to be shared between the aggregator and the customer, assuming that the aggregator will at least pay a reward to the customer to cover the increase in customer's electricity bill (see Table 5-4).

**Table 5-4 – Financial impact indication for customer (MEUR)**

| | Model A | Model B | Model C |
|---|---|---|---|
| Income from flexibility | 0.9–1.2 | 0.9–1.2 | 0.3 |
| Increases in electricity bills | 0.7–1.1 | ~0 | 0.2 |
| **Net result*** | **0.1–0.2** | **0.9–1.2** | **0.1** |

*The amount of money to share between aggregator and customer assuming that the aggregator will at least pay a reward to cover the increases in customer's electricity bill.

Note: In figures above the range varies depending on the amount of flexible hours from 20% to 33%. The rebound duration is assumed to be 2 hours.

The financial impact analysis describes a situation where supplier can transfer all the costs to the customers who are causing the costs. However, this might not be the case in most situations. In practice, residential and Small & Medium Enterprise (SME) customers have contracts based on list prices. These list prices cannot be increased for one customer only. This would lead to a situation where costs are shared between all the customers, i.e. there are additional costs for customers not participating in DSR.

Industrial customers with large consumption typically have bilateral contracts for buying electricity in addition to traditional DA and ID procurement. In this case, it is possible to re-negotiate the contract terms and price if the contract is not fixed term. If the industrial customer's contract is based on a certain consumption profile, the profile cost can in some cases be transferred directly to the customer.

Increasing retail prices would lead to a situation where the supplier with flexible demand on portfolio loses competitive position compared to its competitors, as the markets set the retail price of electricity. These cases lead to a result where the suppliers rarely have an option to fully transfer the costs to the customers who are causing them. It could be that the supplier has no other option than accept the costs caused by customers offering flexibility through aggregator service.

There could be an interesting dynamic around the reaction of suppliers through a longer-term shift in relative competitive pressure across customer groups. The 'traditional' suppliers would compete more strongly in less flexible segments of the market because they cannot bear the risk in the flexible part, so in the longer-term prices would start to go up to the flexible customers and/or aggregators would end up having to become more like traditional suppliers.

In summary, having customers who participate in DSR through an aggregator can have a negative impact on the profitability and competitive position of the supplier. This can be seen as acceptable if the aggregated volumes of flexible customers remain moderate.

### *5.1.4 Other suppliers and balance responsible parties*

Other suppliers and BRPs refer to suppliers and BRPs whose loads are not participating in DSR via aggregation. In models A and C the other BRPs are not affected by the aggregator. Both the costs caused and compensations paid are directed to the BRP whose loads are aggregated. In model B the TSO pays the imbalance price to the BRP for being long during the up-regulation hour. If the TSO includes this cost in the balancing service fees, the cost is socialized to all BRPs, not just the ones who have aggregating demand. Balancing service fees are based on consumption and production volumes in the portfolios of the BRP, so the BRPs with largest volumes are affected the most.

To further estimate the impact of socialized costs for all BRPs in model B, the increased imbalance costs for the TSO need to be assessed as costs per MWh according to annual consumption or generation. In our calculation, the TSO's costs would increase by 1 MEUR in model B due to the imbalance price paid to the BRPs whose loads participate in DSR. If this cost is covered by increasing the balancing service fees for consumption (86 TWh), the increase would be 0.012 EUR/MWh. If the cost is covered by generation (65 TWh) the increase would be 0.015 EUR/MWh.

### *5.1.5 Balancing service providers*

In models A and B, the independent aggregator is not required to compensate the offered flexibility for any BRP. This leads to an unequal competitive position compared to other BSPs. In model C, the compensation of DA price for the BRP results in more equal competitive position – there is no large difference to integrated model, where the aggregator is balance responsible.

## 5.2 Demand-side response participating in other markets

Analysis in chapter 5.2 was done based on balancing market data. This chapter describes the impacts where DSR is offered in other market places.

### *5.2.1 Day-ahead market*

The day-ahead market has not been analysed in this section. Section 5.4 looks at what impact DSR provided by independent aggregators could have on market prices in the day-ahead market.

### 5.2.2 Intraday market

Aggregators can offer the demand-side response to the intraday market as well. In this case the impacts on different stakeholders would be similar as in the case where the aggregator bids to the balancing market with following exceptions:

- In models A and B the aggregator can offer DSR with a price that is less than the DA price for the hour. This was not the case in balancing market as the balancing prices are always higher than DA prices if up regulation is activated.
  - Theoretically this means that it is possible that the aggregator would bid more frequently if participating in ID market than in balancing market. This could in theory lead into a situation where DSR is offered to the markets even more frequently than 33% of the hours in a year.
  - In practice the amount of DSR hours is dependent on the price expectation the aggregator has for bidding in the ID market.
- In model C the aggregator has to compare the ID prices with the DA price or any other price used for compensation.
  - This limits the aggregator's possibilities to insert a bid compared to the situation with model A and B.
- In all models supplier and BRP would have some time to react to the aggregator's bid, if the DSR is offered to the ID market.
  - In this case the challenge is that the supplier and BRP do not know if the aggregator has bid or not as the aggregator is not obliged to inform the supplier or BRP.
  - It is possible that in long term the supplier learns to anticipate aggregators bidding logic from historical events meaning that the supplier would learn that certain combinations of DA prices and ID prices mean that the aggregator is probable to insert a bid and DSR would be activated.
  - This way supplier could try to mitigate the risk relating to purchasing of surplus energy for the DSR hour as the supplier could try to sell the surplus in ID or balancing market in case they know that DSR will be activated. In addition, depending on the notification time and rebound characteristics, the risk of rebound costs could be mitigated by purchasing additional electricity from ID or balancing markets for the rebound hour.

### 5.2.3 Other TSO markets

In reserve markets, aggregators need to be able to regulate consumption according to the market rules (see 3.1.2). This can be a challenge in providing demand response, as there are minimum bid sizes and technical requirements for e.g. activation times.

*Balancing capacity market*

The balancing capacity market is based on similar market rules as the balancing energy market. There would be increase in capacity payments compared to energy payments due to less activations (see section 3.1.2), leading to lower impacts on other market participants in each model, but otherwise similar conclusions apply as in section 5.1.

*aFRR market*

The aFRR market is based on same kind of market rules as the balancing energy market and similar conclusions apply as in section 5.1.

*FCR-N market*

FCR-N was assessed based on the same assumptions that were used for the balancing market (see section 4.3). FCR-N is a symmetrical product and the activated energy amounts are roughly equal for up- and down-regulation. The rebound effect is not taken into consideration, as there are both up- and down-regulation evenly, which over the course of the year evens the effect, making it insignificant. Additionally, the activated volumes in MWh terms are only a share of the around 10 MW offered capacity per hour, proportional to the ordered capacity per hour compared to the

Fingrid's share of FCR-N obligation around 140 MW. For example, if there are 70 MW activated reserves, only half of the potential aggregated volume is activated.

If the hourly imbalances due to FCR-N activations are not corrected, the additional imbalance cost for BRPs is 0.05 MEUR, i.e. procurement costs would slightly increase. However, this imbalance cost equals only to 2% of the procurement costs for the flexible part of the demand. As stated before, this forms only a small part of the BRPs' total demand portfolio, hence affecting the total procurement costs only marginally.

In the current model in use in the Finnish FCR-N market the BRP is compensated for the activated energy based on the regulation prices (i.e. model C with regulation prices as instead of the DA price). In this scenario, the imbalances profit BRP for a total of 0.05 MEUR. This would lead to a slightly positive net position for the BRP.

In all the models evaluated, the aggregator's net position is positive, due to the capacity payment received. If the aggregator is able to offer capacity for each hour of the year, the capacity payments reach a total of 1.1 MEUR in 2017 prices (13 EUR/MW,h in the annual market). The energy payment equals to only around 5% of the total income, while the rest is capacity payment, hence the energy payment does not affect the final position of the aggregator that much.

In addition, the assumption of 0.1% of hourly demand corresponds to roughly 10 MW,h on average. This results in a 7% market share in the FCR-N market provided through independent aggregators. It is quite ambitious when compared to current 4 MW of DSR offering FCR-N in total. In FCR-N market, the technical requirements and symmetrical bids required might result in challenges for aggregators, as the consumption of multiple loads needs to be regulated both up and down smoothly according to the frequency.

To conclude the impact on electricity procurement costs for suppliers is small if the aggregator acts in the FCR-N market regardless of the model in use.

#### *FCR-D market*

There is no data available on FCR-D activations, but the activations were evaluated according to the frequency data. According to it, FCR-D activations are rare, as the frequency does not drop below 49.9 Hz that many times during 3 minute periods in the years 2016-2017. The full activation is only at 49.5 Hz which was not recorded once in those periods. Noteworthy is that there were no periods with frequency below 49.7 Hz during 2016-2017, which is when relay-connected loads providing FCR-D are disconnected.

To evaluate imbalance costs due to FCR-D activations, hours with the lowest frequencies from the last two years were assessed to see whether activations due to disturbances in the system coincide with high imbalance prices. The analysis showed that the imbalance prices stay on quite normal level considering the other imbalance prices around the period of low frequency. In addition, there is no significant difference between the imbalance price on the hour and the next hour, considering the potential rebound effect. This concludes that there is not significant imbalance or rebound costs based on the recent historical data.

Currently, model B is in use in the FCR-D market, i.e. there is no correction or compensation included. There is no energy handling at all in the FCR-D market, hence there is no need for the correction or compensation in case the independent aggregators provide DSR. The final conclusion is that activations of FCR-D happen rarely and they do not seem to coincide with high imbalance prices. This result supports the reasoning for choosing this current model in use.

## 5.3 Impact on retail market and DSR business potential

The additional costs caused by aggregator services would be included in retail contracts and prices to some extent, although the suppliers are not able to fully transfer the costs to the customers causing them as described in chapter 5.1.3.

The introduction of an independent aggregator model impacts also on the DSR business potential. The amount of aggregators offering DSR services to customers increases and would be highest in models A and B as these are the most attractive models from aggregator's perspective. As the offering of aggregator services increases the amount of customers interested in offering DSR via aggregators is likely to increase as well due to increased awareness of these services. The customers' interest in aggregator services would be highest in model B as this is the most attractive model for customers due to low increase in costs and highest possible revenues to share between the aggregator and the customer.

Especially models A and B could increase the amount of DSR offered to the markets as they are the most attractive from both aggregator and customer perspectives. As a result the value of flexibility and DSR business potential decreases due to cannibalization effect which is characteristic for DSR. The more the offering of DSR increases, the less value can be gained from offering DSR. In addition, the business potential for other DSR services decreases. This is because the aggregator services gain competitive advantage over other DSR services as the aggregator can offer DSR to the markets on a price that does not reflect the actual cost of flexibility, especially in models A and B.

In the long term, there may be benefits from increased competition overall and hence lower margins or costs (e.g. more efficient procurement by suppliers) but there may also be reactions from suppliers to the entry of aggregators and also an additional impact on the value for aggregators as the number of aggregators increases. In other words, there has to be some beneficial reduction in average imbalance prices relative to a situation when (supposedly cost effective) DSR is not offered to the market, which lowers total procurement costs for all suppliers.

## 5.4 Impact on electricity markets and market prices

### *Cost efficiency*

In models A and B the marginal cost for the aggregator to provide demand response is lower than in model C or when compared to integrated aggregation. This means that in models with no compensation the flexibility offered by the aggregator is not competing on equal terms with other balance service providers. Flexibility offered by an independent aggregator in models A and B does not have the same marginal cost if it were offered by the supplier - even though the physical resource is the same. This could lead to a situation where cheapest resources are not activated and an issue around efficiency of cost, assuming that the additional costs to suppliers are not signaled somewhere else in the pricing structures, e.g. through higher retail tariffs. If retail prices are increased, customers would require a higher share of revenues from any DSR activity and lower the value to the aggregator.

### *Market prices*

In an energy-only market, the price of energy should provide a reliable signal for short-term efficiency and long-term investment incentives. Energy prices should reflect marginal cost and scarcity, i.e. the marginal cost of all actions required to meet demand for reliable energy. In models A and B the full cost of providing flexibility is not included in the price as some of the costs are transferred to the customer's BRP (model A) or all BRPs (model B). This can be seen to be in conflict with the Nordic energy-only market philosophy.

In the 'no compensation' models there is an extra incentive for DSR and the cost has to be allocated somehow. This approach could be warranted if:

- There is concern of abuse of market power driving up prices.
- There are high barriers to entry for demand-side to participate in different market places.
- Retail customers do not have the opportunity to respond to wholesale prices.

In our opinion none of those are major issues in the Nordic and the Finnish market. Rather than paying for not consuming or transferring the extra costs to other market participants, a better outcome from a market perspective would be more customers exposing the price at which they are not willing to consume explicitly or implicitly (adjusting consumption based on wholesale prices).

If there is a clear need to make demand-side more active in price formation (rather than reacting to prices after the prices have been published), e.g. direct customer compensation could be an alternative approach. However, demand-side is already active in the Nordic wholesale and TSO markets, e.g. in the day-ahead market price formation. In addition, a recent study by Pöyry found that there is on average 300 MW of up-regulation bids in the regulating power market from Finnish demand-side flexibility. This is assumed to be mostly industrial consumption.

In the case of implicit demand-side response, i.e. responding to prices, all Finnish customers have access to dynamic retail tariffs due to smart metering and the Finnish retail market is considered to be competitive with over 50 nation-wide suppliers in 2016.[34] When customers respond to prices, suppliers should over time adjust their demand forecast models and procurement amounts at different price levels, which would lead to the market clearing at lower volumes and prices. In the Finnish market all customers are hourly settled based on the metered consumption. This means that the procurement by suppliers is based on hourly demand forecasts instead of fixed profiles with forecasts for monthly or annual consumption.

## 5.5 Technical and regulatory prerequisites

All of the models require some changes in current electricity market processes. The implementation of new aggregator model might require new regulation and applying of additional technology relating to, e.g., information exchange.

*Information exchange*

Information exchange has a significant role in models A and C as those require imbalance correction before the actual imbalance settlement. This means that the TSO has to define rules in order to identify and measure the aggregator's DSR actions so that the imbalance error caused by the aggregator can be separated from the normal imbalance error. This information must come from a system that is transparent and recognized by all market participants.

Especially in model A suppliers would benefit from information of customers who have contracts with aggregator. This is so that they can potentially take this information into account in their procurement and risk management, or at minimum explain any abnormal in the customer's consumption profiles. Sharing of this information is the current practice in the FCR-D and FCR-N markets.

In case there are no specific requirements set by regulation to share the information about DSR activations the supplier can only try to identify any potential demand-side flexibility from the changes in customers' demand profiles. In model A the information about activation of DSR could help suppliers to mitigate the risk relating to purchasing of surplus energy for the DSR hour as the suppliers could try to sell the surplus in ID or balancing market in case they know that DSR will be activated. In addition, depending on the notification time and rebound characteristics, the risk of rebound costs could be mitigated by purchasing additional electricity from ID or balancing markets for the rebound hour. It is notable that this kind of operating model requires information exchange and that there is enough time for the supplier to react.

*Imbalance settlement and compensations*

aFRR and mFRR are TSO markets, which have their own verification requirements to be used as basis for compensation for delivery of the balancing services. The same information can then be used to allocate the volumes to different balance responsible parties. The verification and compensation process is currently being piloted by Fingrid and the lessons learned during the pilots should feed into the detailed design of the re-allocation and compensation process.

Implementing model C in the intraday market is likely to be a bit more challenging as the metering data provided by the aggregator would have to be approved in the imbalance settlement. This could be solved by, e.g., extending the verification process used in the balancing markets to apply in the intraday market as well.

Model C requires definition of the compensation prices. There are many possible reference prices that could be used in theory as described in chapter 3.2 and these all have their advantages and disadvantages. Day-ahead price would be straightforward as it is public information and every market participant has access to it. On the other hand, DA price as compensation does not take into account the supplier's loss of sales from the DSR hour. Retail price, which consists of day-ahead price and supplier's margin, would include the loss of sales margins due to DSR but requires

[34] Source: Finnish Energy Authority. National Report 2017 to the Agency for the Cooperation of Energy Regulators and to the European Commission. Finland.

sharing of business sensitive information and customer acceptance. Other reference price defined by, e.g. Energy Authority would also be possible. In this case it should be made sure that the regulated compensation reflects the price of electricity during the DSR hour.

In model B the supplier is compensated by the TSO through imbalance settlement for being long during the DSR hour. In this case the TSO needs to define how the purchased or sold imbalance energy is collected and credited in the imbalance settlement. For this purpose TSO can, e.g., increase balancing service or network service fees.

*Prerequisites in model D*

Model D requires separate metering for the flexible and non-flexible consumption which causes potentially high set-up costs. A similar model has been discussed also in Denmark and it is recognized that this kind of model would require establishment of a sub metering point which leads to relatively high entry costs[35]. It is also worth noting, that there are some initiatives that are starting to look at ways of approximating split metering without additional assets. For example Elexon in Great-Britain has put forward an option for dealing with multiple suppliers at a single account through centralised validation agent to allocate flows between suppliers.[36] As this kind of solutions are still in early idea phase, it is not seen very realistic in short-term. On the other hand, these solutions might become more common by the time aggregation becomes common practice, and thus they might open new possibilities in long-term.

In addition model D requires re-definition of relevant market processes to include the possibility for multiple suppliers per customer. This is likely to have influence, e.g., in metering practicalities and definitions.

*Contractual issues and separation of electricity supply and aggregator businesses*

The duration of a fixed term electricity supply contract is currently limited to maximum of two years. This means that if a supplier decides to act as an integrated aggregator and bundles aggregator services to the electricity supply contract, the aggregator service contract is likely to be also limited to two years. An independent aggregator would gain competitive advantage as its contracts are not limited for a fixed term. This contractual issue might incentivise the suppliers not to bundle aggregator services with traditional supply contracts and even to separate aggregator business from the traditional electricity supplier business. In addition, it might become attractive for suppliers to separate their aggregator business from supplier business and start to aggregate flexible loads actively from other BRPs' customers to avoid the cost impacts caused by DSR.

Especially model B encourages the supplier to separate supplier and aggregator businesses. This is because imbalance revenues are higher than rebound costs as shown in chapter 5.1.1 and therefore it is more profitable even for the BRP to offer DSR through the independent aggregator model, as they would receive the benefit both from selling balancing services and selling their surplus back to the TSO through the imbalance settlement, if there is no regulation in place restricting the possibility for arbitrage

[35] Danish Energy Association, Energinet.dk, Confederation of Danish Industry, Danish Intelligent Energy Alliance: Market Models for Aggregators – Activation of flexibility. Available at: https://tinyurl.com/y8h7p3up

[36] Elexon White Paper: Enabling customers to buy power from multiple suppliers. Available at: https://tinyurl.com/y7q5o4fz

# 6. SUMMARY AND RECOMMENDATIONS

The financial impact assessment in sections 5.1 and 5.2 focused on the distributional effects and especially their relative difference in the different models. Dynamic effects were not quantified in the financial impact assessment. These include issues such as:

- value of flexibility in the system and cost of providing demand-side flexibility;
- the increase in provision of demand-side flexibility in the different of models;
- impact of DSR on market prices and reduced need for generation or network investments in the long term;
- impact of DSR on improving energy efficiency and lowering total demand; and
- impact on market participant behaviour, such as suppliers changing their approach to pricing and risk management or becoming aggregators themselves.

These issues were discussed separately in sections 5.3-5.5.

This section presents the summary of our analysis and the recommendations based on the approach above.

## 6.1 Evaluation of the models

Table 6-1 summarises the distributional analysis from the perspective of different stakeholder groups. The evaluation of the different models against a set of market design criteria, shown in Table 6-2, in Table 6-3 summarises the analysis in section 5 as a whole.

The evaluation of the different models can be summarised as follows:

- In model A the customer's supplier faces the highest risk for increased procurement costs of the analysed models. This could then lead to a situation where the additional imbalance costs are charged to the customer through higher retail prices. If retail prices increase, customers would require a higher share of revenues from any DSR activity and thus lower the value to the aggregator.
  - In the longer-term this could lead to a shift in relative attractiveness of customer groups to suppliers. The 'traditional' suppliers would compete more strongly in less flexible segments of the market because they cannot bear the risk in the flexible part, so prices would start to go up for the flexible customers and/or aggregators would end up having to become more like traditional suppliers.
- Model B has the most benefits for the customer participating in demand-side response through an independent aggregator, but leads to highest additional costs which are socialised to all market participants.
  - The marginal cost for the independent aggregator to provide demand response is lower than if it were offered by the supplier, although the physical resource is the same. This means that the aggregator is not competing on equal terms with other balance service providers. This could lead to a situation where cheapest resources are not activated.
  - There is also a risk that this could lead to situations where it is more profitable for the balance responsible parties to offer demand-side flexibility through the independent aggregator model. This is because they would receive the benefit both from selling balancing services and selling the surplus back to the TSO through the imbalance settlement, if there is no regulation in place restricting the possibility for arbitrage.
- Model C has the least distributional effect to the customer's supplier through increased imbalance costs; other BRPs through increased balance service fees; and other balance service providers through unequal competitive position.
  - Model C could have the biggest direct implications for the TSO as they would be responsible for the re-allocation of imbalance volumes and administering the process for the compensation payments.

Model D, the 'split metering point' or 'multiple suppliers' model, was not analysed in detail as strictly speaking it is not a model for independent aggregation. As this kind of solution is still in an early concept phase, it was not seen to be feasible for implementation in the short term. It is an interesting concept in the long-term opening up new possibilities in the retail market in general, not only related to demand-side response.

**Table 6-1 – Summary of impact on customers and market participants**

| Stakeholder group | A. Imbalance volume correction | B. No correction or compensation | C. Correction + compensation |
|---|---|---|---|
| Customer | ▪ More benefits to participate in DSR compared to model C<br>▪ Risk of increased retail prices due to increased imbalance costs for the supplier | ▪ Most benefits to participate in DSR as supplier is better off as well compared to other models | ▪ Less benefits from DSR due to the compensation to the supplier<br>▪ Small risk of increased retail prices |
| BRP / supplier of the customer | ▪ The costs to procure electricity for flexible customers increase clearly | ▪ The imbalance revenue roughly compensates for the rebound effect | ▪ Procurement costs for flexible customers increase somewhat |
| Aggregator | ▪ Higher net position compared to model C, which could be lower if needs to compensate the customer due to higher retail tariffs<br>▪ Has to provide data for the volume correction | ▪ Highest net position as all benefits can be shared with the customer | ▪ Lower net position as needs to share income with the customer and compensate the supplier |
| TSO | ▪ Cash neutral<br>▪ Responsible for volume correction | ▪ Double pays for flexibility, which needs to be collected from other BRPs | ▪ Cash neutral<br>▪ Responsible for volume correction and allocating compensation |
| Other balance service providers | ▪ Unequal competitive position | ▪ Unequal competitive position | ▪ No large difference to integrated model |
| Other BRPs | ▪ No impact | ▪ Increased balancing service fees, which are volume-based | ▪ No impact |

**Table 6-2 – Market design criteria and key questions**

| Criteria | Key questions |
| --- | --- |
| **Increase customer participation and business potential for DSR** | ▪ Does the model facilitate DSR market growth without facing discrimination or entry barriers? |
| **Distributional effects on stakeholders** | ▪ Is there a risk of negative impact on retail prices (from an increase in administrative costs for market participants or an increase in imbalance costs for BRPs)?<br>▪ How does the model manage the balance between different market participants (suppliers, BRPs, BSPs)? |
| **Efficiency** | ▪ Does the model promote efficient investments?<br>▪ Does the model result in inefficient short-term operation? |
| **Bankability and risk** | ▪ Is the model credible for investment?<br>▪ What is the degree of perceived regulatory risk? |
| **Simplicity** | ▪ How easy is the model to understand and for players to operate within?<br>▪ How complicated is the model to set up and administer? |
| **Competition** | ▪ Does the model increase or decrease competition in the energy market? |

**Table 6-3 – Evaluation of the models against market design criteria***

| Criteria | A | B | C | Comments |
|---|---|---|---|---|
| **Increase customer participation and business potential for DSR** | + | ++ | +/- | ▪ Model B contains the most benefits to be the shared with the customer. |
| **Distributional effects on stakeholders** | -- | -- | ++ | ▪ Model C has clearly the least distribution effects.<br>▪ Models A and B have direct effects on imbalance costs and indirect effects through unfair competitive position for other balance service providers. |
| **Efficiency** | - | -- | + | ▪ Models A and B might lead to overinvestment<br>▪ As the total cost of providing flexibility might not be included in the price of flexibility in models A and B, cheapest resources might not always be activated. |
| **Bankability and risk** | + | ++ | +/- | ▪ Model B provides the most benefits to the customer, aggregator and supplier as a whole, leading to shortest payback periods for investment. However, there could be a longer-term risk for regulatory intervention if model B is implemented as a transitional scheme.<br>▪ In model A, increased risk for the supplier may lead to unexpected retail price increases for the customer. |
| **Simplicity** | - | +/- | -- | ▪ Model B is technically the simplest one as there is no need to account for imbalance volume adjustments or allocating compensation between market participants.<br>▪ However, there could be a need for regulatory oversight in model B to make sure that the incentive structure does not lead to arbitrage where a balance responsible party offers flexibility through an independent aggregator model and receives payments from the balancing market and the imbalance settlement. |
| **Competition** | + | ++ | +/- | ▪ Models A and B should bring forward more new players and new service offerings as the potential benefits are higher than in model C. |

*Scoring of the models is based on a qualitative assessment and illustrates the relative difference between the models.

## 6.2 Recommendations

The analysis indicates that model C is the most balanced of the models, provided that issues related to imbalance settlement can be tackled.

In models A and B, independent aggregation would result in a cost that would have to be transferred to the customer's BRP (model A) or all BRPs (model B). The basis for this cost is to bring more DSR to the market. The characteristics of the Finnish market support the choice of model C, namely:

- There is already active demand-side response from heavy industry in the Finnish market.
- Hourly, and in the future 15-min, metering enables dynamic tariffs for retail customers allowing them to respond to wholesale prices.
- The Nordic wholesale market and the Finnish retail market are generally considered competitive.
- There are no explicit barriers to entry for aggregated demand-side response in different market places and the Finnish TSO is active in piloting new technologies and updating market rules to accommodate these technologies.

- The extra cost for demand-side response is in conflict with the energy-only principle of the Nordic market and can have a negative longer-term impact on investment if scarcity is not reflected in the energy prices, i.e. the marginal cost of all actions required to meet demand for reliable energy.

The argument for pursuing other models (such as Model B) would need to be based on a decision that there is a considerable need for DSR and that consequences such as socialisation of costs and potential second order effects are seen as acceptable. Still, if there is political will to develop DSR (i.e. societal benefits outweigh costs), this can be done through other means that would have less of a market distortion than Model B. Such approaches could include e.g. direct investment and innovation support. This type of approach would also reduce the risk for investments in DSR capabilities. This is especially important for smaller scale customers where electricity procurement is only one of the cost items. Stakeholder interviews indicated that customers typically require short payback periods, e.g. 1 year, for investments in DSR.

Table 6-4 summarises the recommendations for different market places.

**Table 6-4 – Recommendations for different market places**

| Markets | Recommendation | Reasoning |
|---|---|---|
| Day-ahead market | Model C | ▪ The easiest way for retail customers to participate in the day-ahead market is to have a dynamic contract based on hourly wholesale prices.<br>▪ If customers react to prices, over timer suppliers should adjust their demand forecast models* and procure volumes at different price levels, resulting in the market clearing at lower volumes and prices. |
| aFRR, mFRR and intraday | Model C | ▪ The basic principle is the same in all these markets: benefit from demand-side flexibility is based on the spread between day-ahead and intraday/balancing prices.<br>▪ aFRR and mFRR are TSO markets, and the metering data provided to the TSO can be used to allocate the volumes and compensation to different BRPs. The verification and compensation process is currently being piloted by Fingrid and the lessons learned during the pilots should feed into the detailed design of the re-allocation and compensation process.<br>▪ The verification process used in the balancing markets could be extended to apply in the intraday market as well in the case of independent aggregation. |
| FCR | Model B (FCR-D)<br>Model C (FCR-N) | ▪ Most or all of the compensation is based on capacity payments so model impact is limited.<br>▪ Model B is already in use for FCR-D and it is activated so rarely that the impact on BRPs is very minor.<br>▪ In case of FCR-N, the energy compensation is already allocated to the BRPs and the aggregator gets to keep the capacity payment. The analysis also indicates that the impact on BRPs is likely to be minor in any case. |

* In the Finnish market all customers are hourly settled based on the metered consumption. This means that the procurement by suppliers is based on hourly demand forecasts instead of fixed profiles with forecasts for monthly or annual consumption.

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